DIVIDER

STATE OF NORTH DAKOTA
INFORMATION TECHNOLOGY DEPARTMENT
SFN 2053 (4-2002)

PU-399-02-183
Montana-Dakota Utilities Co., a Division of MDU Re
Natural Gas Rate Increase
Application 02
Filed 4/12/2002 Closed 8/4/2003

DESCRIPTION

PU-399-02-183
Public Input

Scott, Sandi L.
From: Jeffcoat-Sacco, Illona
Sent: Monday, July 07, 2003 11:15 AM
To: Legal
Subject: FW:

Illona A. Jeffcoat-Sacco
ND PSC
701-328-2407 (fax 2410)
ijs@oracle.psc.state.nd.us

-----Original Message-----
From: Wefald, Susan E.
Sent: Monday, July 07, 2003 11:03 AM
To: Comm; PUD
Subject:

John Kaisershot , Dickinson called. His phone number is 1-701-227-0109. He reminded me that he was one of the people who attended the MDU Natural Gas Hearing in Dickinson last year. Today he was calling about the proposed increase in MDU electric prices. He said that MDU stock has gone from a –18% return on Oct. 1, 2002 to +32% return as of July 3, 2003. I told him that I would put this information in the public input file

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Leo M. Reinbold
Susan E. Wefald

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

April 21, 2003

Myrtle Beaudoin
1706 6th St NW
Minot ND 58703-1304

Dear Mrs. Beaudoin:

Thank you for writing us concerning your MDU gas rate increase. In 2002, Montana Dakota Utilities filed an application with the Public Service Commission to increase its gas utility rates for North Dakota customers. MDU was authorized to implement an increase in rates effective December 12, 2002.

Almost the entire increase approved by the Commission for natural gas service is noticed in the "Basic Service Charge" which is now expressed as 29 cents per day. Before January 18, the basic service charge was $6.50 per month.

Another increase you might notice is in the PGA. This increase is primarily an increase in the price of the natural gas purchased by MDU from gas producers. A gas utility typically buys gas wholesale and sells it to customers at cost. In the current situation, higher gas prices are the result of price increases at the wellhead for what is called commodity gas. Natural gas is a commodity, and the price of natural gas shifts depending on supply and demand. The price of commodity gas was deregulated by Congress starting in 1978, with state and federal regulators having no jurisdiction over the commodity price. Rather, the market sets the price largely on the basis of actual and expected supply and demand conditions. Changes in the price of commodity gas get passed through to consumers on a monthly basis through a "gas adjustment" mechanism. That price fluctuates from month to month and has been going up the last couple months.

Sincerely,

Sharon Helbling
Public Utilities Division

sdh

RECEIVED
APR 21 2003
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

4-16-03

Public Service Commissioners

I would like to thank you for the 1½ increase on the Natural gas prices. To me it doesn't Make much sense to increase your give to Them so they Can go out buy up more Business the rich get richer and poorer get more poor. Turn your Thermostat down to 60 at Nite and 65 in the day time and your Gas prices are still high. Ya people Wonder about the Economy going up. Have Can it go up, When Jobs go up 200.00, Gas gets way up and the increase in your Natural Gas prices don't help it one bit. We are tired. I think you people we elect should thinking about the people that are making ends meet house payments and raising a family. or is it just the me game.

We are tired of and living on a
fixed income. Maybe ok should
pitch a tent and live in it.
You like people to stay in state of No Dak.
the low wages & high taxes don't
help and but plus the high utilities Bills
Thank you
Sincerely Myrtle Beaudoin
1906 - 6th St No West
Minot, No Dak 58703.

We live in Bismarck Dak
read in the Bismarck paper
that Montana - Utah are buying
3 different Businesses Take away
from the people to put their own
pockets.

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

November 4, 2002

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
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TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

Mrs. Myrtle Beaudoin
1706 6th St NW
Minot, ND 58703-1304

Dear Mrs. Beaudoin,

Thank you for your concern about North Dakota. I agree with you that it is hard for young people to make a good living in North Dakota. That is often the case in rural states and rural areas with limited resources and business enterprises. The Public Service Commission is not directly involved in state economic development activities. However, we work hard to keep electric and gas rates as low as possible and hopefully that will aide in the development of business activity.

Your letter speaks of high gas prices in 2000 as well as projected increases of 45% for this winter. The prices seen in early 2000 were extremely unusual and record gas prices were set all over the country. The prices you pay for natural gas are based on the cost of the gas itself, transmission costs to get it to town and then distribution costs to deliver the gas around town. Of these three components, the commission has regulatory control over the distribution costs. These costs change during rate cases and are normally quite small and infrequent.

The cost of gas itself is market driven and goes up and down depending on available supply and demand for gas. The U.S. gas supply comes from domestic wells, foreign imports and gas in storage. Once that available supply begins to erode, prices go up to reflect the change in the availability of gas. The opposite is true when extra gas reserves are available. The cost of the gas itself is primarily responsible for the big changes in natural gas bills. This is true for 2000 and the projected increases this winter. The cost of gas is not controlled by the commission or any other governmental agency but reflects current market conditions normally found in the buying and selling of any commodity.

Based on current gas storage levels, it is unlikely that we will see 45% increases in natural gas prices. However, there are many factors that can

affect the supply and demand of natural gas making it impossible to predict its price with any degree of certainty.

I hope this letter is useful. Thanks again for your interest in our state and the price of natural gas.

Sincerely,

Mike Diller

Mike Diller
Director of Accounting

c: Commissioners

RECEIVED
OCT 30 2002
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

VOLUNTEERS
Serving Home, Church and Community

10-29-02,

To the Public Service Commission

I recently heard there is a 45% increase in our heating bills. I myself think it outrageous. We went to a Meeting here at the College in Jefferson Hall. I can't quite understand as a Caring person. How you people that we vote in, give these big companies these increases. As you people know many young people work for less than $8.00 pay hr hours on their Homes and try to raise a family and pay all their utilities besides. Just because some people are born with a gold spoon in their mouths. Is a sign Everyone has the same chance. We vote for these

MDU Gas Case

LUTHERAN BROTHERHOOD

VOLUNTEERS

Serving Home, Church and Community

With big promise but that all,
We need a big change
Pretty soon. But We want
have our young people here
The year of 2000 look how
they sip the people off.
some people didn't know if
they will pay the heating bill
or put food on the table.
You people better wake up.
After the year of the 2000
The gas companys were braggging
how many Millions of Dollars they
Made. I think its a sin to
Steal. Thank you thats all I
have to say.

Sincerly Myrtle Beardsley

LUTHERAN BROTHERHOOD

4408

Regarding: Gas | Subject: MDU Gas Rate Increase | Added: 10/8/2002 13:39:24

Company: MDU

Location: | BusinessType: IOU | 200000009986

Caller Info: Name - First: Evelyn | Last: Bjorness

Represents:

Address:

City: Dickinson | St: ND7 | Zip:

Phone: | E-mail:

Public Utilities

Detailed - On Agenda

Helbling

Resolved: 10/08/02 01:39 PM | **Jurisdictional:** Ye● No○ | CM Year: **02** Seq: **183**

Explanation of Issue: | Refered To:

Is against increase.

Resolution:

Additional Notes:

MDU contact: tamie.aberle@mdu.com; karen.collins@mdu.com;

RECEIVED
JUL 19 2002
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

7-17-02

Attention Tony
and Rest of Industrial Comm. members

I'm ~~co~~writing in Regard to the Increase in the price of M.D.U. gas that they want to take effect I think this is a very excessive increase. I'm a council member in a small town in western N.D. and we are trying to keep our Resident's in there homes as long as we can so the propety taxes are paid and not returned to the city. We have a lot of elder people in our community and they are on a fixed income and they have trouble with these extra bills. I personally dont see why M.D.U. needs such an increase to double there base charge. I hope you people consider this increase very careful for everybodies good not just M.D.U.'s.

CC: Comm
Tiegen
Pud

Larry W Kalmas
Box 507
Belfield, N. Dak. 58622

Public Service Commission
State of North Dakota

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web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

July 10, 2002

Eulalie Heidt
227 4th St E
Dickinson ND 58601

RE: Case No. PU-399-02-183

Dear Ms. Heidt:

Thank you for your recent letter concerning MDU recent natural gas rate increase application. Your letter has been filed in the Public Input file for this case, and copies have been provided to the Commissioners.

We appreciate your interest. The formal hearing on this matter has been scheduled for October 7, 2002 in the Commission Hearing Room on the 12th Floor of the Capitol Building. You are welcome to attend. Public Input sessions have also been scheduled, one in Dickinson. A copy of the Notice of Hearing is enclosed.

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

Enclosure

Dickinson, N.D.
July 1, 2002

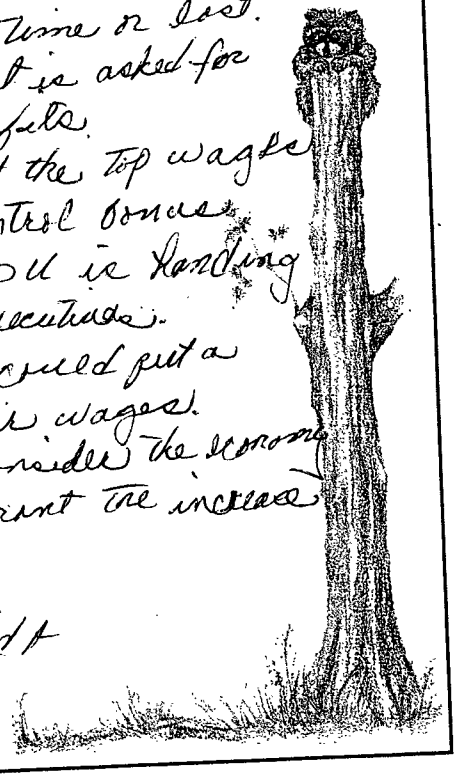
A note from:
Eulalie Hiedt

RECEIVED
JUL 10 2002
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

N.D.P.S.C.
Bismarck, ND

This is not a good time to raise utility rates for Montana-Dakota. The economy is at a stand still. Full time jobs are replaced by part-time or lost. Early retirement is asked for with lost benefits.
Take a look at the top wages and out of control bonus packages MDU is handing out to their executives.
Perhaps they could put a freeze on their wages.
I hope you consider the economy before you grant the increase.

Sincerely,
Eulalie Hiedt



RECEIVED
APR 12 2002
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

MONTANA-DAKOTA UTILITIES CO.

CASE NO. PU-399-02-___
STATEMENTS A - O

In the Matter of the Application of
Montana-Dakota Utilities Co. for
Authority to Establish Increased Rates
for Natural Gas Service in the
State of North Dakota

EXHIBIT
2-2

2 PU-399-02-183 Pages: 161
Statements A - O
by Montana-Dakota Utilities Co , a Division of MDU Re
Exhibit # 2-2
04/12/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

MONTANA-DAKOTA UTILITIES CO.

CASE NO. PU-399-02-____

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MONTANA-DAKOTA UTILITIES CO.
BALANCE SHEET
DECEMBER 31, 2000 AND
DECEMBER 31, 2001

	2000	2001
Assets and Other Debits		
Utility Plant	$811,860,363	$822,190,372
Construction Work in Progress	4,386,767	10,660,010
Less Acc. Provision for Depreciation and Amortization	447,997,314	472,283,724
Net Utility Plant	368,249,816	360,566,658
Gas Stored Underground - Noncurrent	1,195,374	2,795,330
Other Property and Investments		
Nonutility Property	133,220	140,013
(Less) Accum. Prov. for Depr. And Amort.	25,123	36,353
Investment in Subsidiary Companies	730,436,178	956,558,029
Other investments	24,559,856	25,822,974
Net Other Property and Investments	755,104,131	982,484,663
Current and Accrued Assets		
Cash	7,072,666	3,131,759
Special Deposits	1,200	1,200
Working Fund	16,029	16,015
Temporary Cash Investments		1,906,817
Customer Accounts Receivable	47,495,868	22,175,582
Other Accounts Receivable	4,258,848	2,525,644
(Less) Accum.Prov. For Uncollectible Acct. - Credit	554,752	333,634
Accounts Receivable from Assoc.Companies	11,279,658	12,316,880
Fuel Stock	1,746,988	2,008,080
Plant Materials and Operating Supplies	6,288,886	5,758,377
Merchandise	960,692	911,650
Gas Stored Underground - Current	5,895,908	25,481,101
Prepayments	7,533,214	9,371,438
Interest and Dividends Receivable	10,811	
Accured Utility Revenues	40,145,126	19,354,571
Miscellaneous Current and Accrued Assets	224,057	512,238
Total Current and Accrued Assets	132,375,199	105,137,718
Deferred Debits		
Unamortized Debt Expenses	1,392,023	1,257,574
Other Regulatory Assets	3,838,483	3,470,463
Prelim. Survey and Investigation Charges (Electric)	32,712	338,503
Clearing Accounts	(167,067)	(22,715)
Miscellaneous Deferred Debits	5,017,758	14,177,327
Unamortized Loss on Reaquired Debt	8,124,801	6,829,294
Accumulated Deferred Income Taxes	19,658,579	19,215,849
Unrecovered Purchased Gas Costs	(8,771,627)	(27,705,734)
Total Deferred Debits	29,125,662	17,560,561
Total Assets and Other Debits	$1,286,050,182	$1,468,544,930

MONTANA-DAKOTA UTILITIES CO.
BALANCE SHEET
DECEMBER 31, 2000 AND
DECEMBER 31, 2001

	2000	2001
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$65,267,567	$70,016,851
Preferred Stock Issued	16,500,000	16,400,000
Premium on Capital Stock	521,464,938	649,500,861
(Less) Capital Stock Expense	2,694,284	2,980,351
Retained Earnings	43,340,068	41,349,699
Unappropriated Undistributed Sub Earnings	257,307,989	353,291,342
Total Proprietary Capital	901,186,278	1,127,578,402
Long-Term Debt		
Bonds	130,850,000	130,850,000
Other Long-Term Debt	43,043,971	27,500,000
(Less) Unamortized Discount on Long-Term Debt-Debit	50,006	45,561
Total Long-Term Debt	173,843,965	158,304,439
Other Noncurrent Liabilities		
Accumulated Provision for Injuiries and Damages	1,195,672	1,302,912
Accumulated Provision for Pensions and Benefits	16,950,167	18,445,259
Total Other Noncurrent Liabilities	18,145,839	19,748,171
Current and Accrued Liabilities		
Notes Payable	8,000,000	
Accounts Payable	34,769,716	15,329,149
Accounts Payable to Associated Companies	6,047,863	4,927,109
Customer Deposits	1,200,063	1,463,945
Taxed Accrued	16,297,690	16,841,333
Interest Accrued	2,319,289	2,256,546
Dividends Declared	14,422,621	16,108,133
Tax Collections Payable	2,062,760	1,170,254
Miscellaneous Current and Accrued Liabilities	8,101,718	9,892,517
Total Current and Accrued Assets	93,221,720	67,988,986
Deferred Debits		
Customer Advances for Construction	2,635,070	1,702,961
Accumulated Deferred Investment Tax Credit	4,373,350	3,642,062
Other Deferred Credits	1,442,584	9,261,453
Other Regulatory Liabilities	15,423,176	16,324,041
Accumulated Deferred Income Taxes	75,778,200	63,994,415
Total Deferred Credits	99,652,380	94,924,932
Total Liabilities and Equity	$1,286,050,182	$1,468,544,930

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) __ A Resubmission	12/31/2001	Dec 31, 2001

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 1
Summary of Significant Accounting Policies
Basis of presentation
The consolidated financial statements of MDU Resources Group, Inc. and its subsidiaries (company) include the accounts of the following segments: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, and construction materials and mining. The electric and natural gas distribution segments and a portion of the pipeline and energy services segment are regulated. The company's nonregulated operations include the utility services, natural gas and oil production, and construction materials and mining segments, and a portion of the pipeline and energy services segment. For further descriptions of the company's business segments see Note 10. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generation stations.

The company's regulated businesses are subject to various state and federal agency regulation. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the company's nonregulated businesses.

The company's regulated businesses account for certain income and expense items under the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Regulation" (SFAS No. 71). SFAS No. 71 requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items is generally based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 2 for more information regarding the nature and amounts of these regulatory deferrals.

Prior to the sale of the company's coal operations as discussed in Note 10, intercompany coal sales, which were made at prices approximately the same as those charged to others, and the related utility fuel purchases are not eliminated in accordance with the provisions of SFAS No. 71. All other significant intercompany balances and transactions have been eliminated in consolidation.

Allowance for doubtful accounts
The company's allowance for doubtful accounts as of December 31, 2001 and 2000, was $5.8 million and $4.1 million, respectively.

Property, plant and equipment
Additions to property, plant and equipment are recorded at cost when first placed in service. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost and cost of removal, less salvage, is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described below, the resulting gains or losses are recognized as a component of income. The company is permitted to capitalize an allowance for funds used during construction (AFUDC) on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $6.6 million, $5.2 million and $1.7 million in 2001, 2000 and 1999, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for natural gas and oil production properties as described below.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2001	Dec 31, 2001

NOTES TO FINANCIAL STATEMENTS (Continued)

Goodwill and other intangible assets
The excess of the cost over the fair value of net assets of purchased businesses is recorded as goodwill and was being amortized on a straight-line basis over estimated useful lives for recorded goodwill in place at June 30, 2001. However, Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which the company adopted as of January 1, 2002, as discussed later in Note 1, requires the discontinuance of goodwill amortization for the company's recorded goodwill at June 30, 2001, on January 1, 2002. Goodwill acquired after June 30, 2001, was subject immediately to the nonamortization provisions of SFAS No. 142.

Goodwill, net of accumulated amortization, was $174.2 million and $91.4 million as of December 31, 2001 and 2000, respectively. Goodwill is included in deferred charges and other assets. Goodwill amortization expense was $4.8 million, $7.0 million and $2.0 million for 2001, 2000 and 1999, respectively.

Impairment of long-lived assets and intangibles
The company reviews the carrying values of its long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and annually for goodwill as required by SFAS No. 142. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In 2000, the company experienced significant changes in market conditions at one of its energy marketing operations, which negatively affected the fair value of the assets at that operation. Due to the significance of the decline, the company recorded an impairment charge against goodwill of $3.9 million after-tax in 2000. The amount related to this impairment is included in depreciation, depletion and amortization. Excluding this impairment, no other long-lived assets or intangibles have been impaired and accordingly, no other impairment losses have been recorded in 2001, 2000 and 1999. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Impairment testing of natural gas and oil properties
The company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units of production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves based on single point in time spot market prices, as mandated under the rules of the Securities and Exchange Commission, and the lower of cost or fair value of unproved properties. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

Due to abnormally low spot natural gas prices that existed on the last trading day of the third quarter of 2001, the company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at September 30, 2001. The lower natural gas prices were largely attributable to a sharp decline in nationwide spot market prices, especially natural gas prices in the Rocky Mountain region, over a relatively short period of time following the terrorist attacks on New York and Washington, D.C. on September 11, 2001, and prior to October 1, 2001. Oil prices likewise experienced a sharp drop during this same period. The company believes the decline in natural gas prices did not reflect

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MDU Resources Group, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2001	Dec 31, 2001

NOTES TO FINANCIAL STATEMENTS (Continued)

the economics of its production assets in that natural gas prices actually being received by the company at the end of the third quarter of 2001 were significantly higher than the spot market prices at that time. In addition, historic natural gas prices have also generally been much higher and only a small portion of the company's natural gas is sold using spot market pricing. As of September 30, 2001, the capitalized costs exceeded the full-cost ceiling and would have resulted in a write-down of the company's natural gas and oil properties in the amount of approximately $32 million after-tax. However, subsequent to September 30, 2001, natural gas prices both nationwide and in the Rocky Mountain region increased significantly, thereby eliminating the need for a write-down of the company's natural gas and oil producing properties.

At December 31, 2001, the company's full-cost ceiling exceeded the company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2001, could result in a future write-down of the company's natural gas and oil properties.

Natural gas in underground storage
Natural gas in underground storage for the company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year is included in inventories and amounted to $28.6 million and $11.0 million at December 31, 2001 and 2000, respectively. The remainder of natural gas in underground storage is included in property, plant and equipment and was $43.1 million and $43.6 million at December 31, 2001 and 2000, respectively.

Inventories
Inventories, other than natural gas in underground storage for the company's regulated operations, consist primarily of materials and supplies of $22.5 million and $20.4 million, aggregates held for resale of $31.1 million and $22.7 million and other inventories of $13.1 million and $9.9 million as of December 31, 2001 and 2000, respectively. These inventories are stated at the lower of average cost or market.

Revenue recognition
Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is probable. The company recognizes utility revenue each month based on the services provided to all utility customers during the month. The company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed below. The company recognizes revenue from natural gas and oil production activities only on that portion of production sold and allocable to the company's ownership interest in the related well. The company generally recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method
The company recognizes construction contract revenue from fixed price and modified fixed price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. Costs in excess of billings on uncompleted contracts of $29.7 million and $13.9 million for the years ending December 31, 2001 and 2000, respectively, represents revenues recognized in excess of amounts billed and is included in accounts receivable. Billings in excess of costs on uncompleted contracts of $17.3 million and $8.0 million for the years ending December 31, 2001 and 2000, respectively, represents billings in excess of revenues recognized and are included in accounts payable. Also included in accounts receivable are amounts representing balances billed but not paid by customers under retainage provisions in contracts which amounted to $20.5 million and $13.7 million as of December 31, 2001 and 2000, respectively.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) __ A Resubmission	12/31/2001	Dec 31, 2001

NOTES TO FINANCIAL STATEMENTS (Continued)

Advertising
The company expenses advertising costs as incurred and the amount of advertising expense for the years 2001, 2000 and 1999, was $2.9 million, $2.0 million and $1.3 million, respectively.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the company is deferring natural gas commodity, transportation and storage costs which are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 24 months to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments amounted to $27.7 million and $8.8 million for the years ended December 31, 2001 and 2000, respectively, and are included in other accrued liabilities.

Income taxes
The company provides deferred federal and state income taxes on all temporary differences. Excess deferred income tax balances associated with the company's rate-regulated activities resulting from the company's adoption of SFAS No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in other accrued liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged customers in accordance with applicable regulatory procedures.

The company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods which conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Earnings per common share
Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options and restricted stock grants. For the years ending December 31, 2001 and 1999, 150,630 shares and 76,500 shares, respectively, with an average exercise price of $36.86 and $23.44, respectively, attributable to the exercise of outstanding options were excluded from the calculation of diluted earnings per share because their effect was antidilutive. For the year ending December 31, 2000, there were no shares excluded from the calculation of diluted earnings per share. For the years ending December 31, 2001, 2000 and 1999, no adjustments were made to reported earnings in the computation of earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Use of estimates
The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as property depreciable lives, tax provisions, uncollectible accounts, environmental and other loss contingencies, accumulated provision for revenues subject to refund, costs on construction contracts, unbilled revenues and actuarially determined benefit costs. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

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Cash flow information
Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2001	2000	1999
		(In thousands)	
Interest, net of amount capitalized	$42,267	$41,912	$30,772
Income taxes	$75,284	$30,930	$32,723

The company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Reclassifications
Certain reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or stockholders' equity as previously reported.

New accounting pronouncements
In June 2001, the Financial Accounting Standards Board (FASB) approved Statement of Financial Accounting Standards No. 141, "Business Combinations" (SFAS No. 141). SFAS No. 141 requires that all business combinations be accounted for using the purchase method of accounting. The use of the pooling-of-interest method of accounting for business combinations is prohibited. The provisions of SFAS No. 141 apply to all business combinations initiated after June 30, 2001. The company is accounting for business combinations after June 30, 2001, in accordance with SFAS No. 141.

In June 2001, the FASB approved SFAS No. 142. SFAS No. 142 changes the accounting for goodwill and intangible assets and requires that goodwill no longer be amortized but be tested for impairment at least annually at the reporting unit level in accordance with SFAS No. 142. Recognized intangible assets with determinable useful lives should be amortized over their useful life and reviewed for impairment in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). The provisions of SFAS No. 142 are effective for fiscal years beginning after December 15, 2001, except for provisions related to the nonamortization and amortization of goodwill and intangible assets acquired after June 30, 2001, which were subject immediately to the provisions of SFAS No. 142. The company adopted SFAS No. 142 on January 1, 2002. The company ceased amortization of its recorded goodwill at June 30, 2001, on January 1, 2002. Goodwill at each reporting unit will be tested for impairment as of January 1, 2002. The company will perform this transitional goodwill impairment test within six months of the date of adoption of SFAS No. 142. However, the amounts used in the transitional goodwill impairment test shall be measured as of January 1, 2002. The company believes the adoption of the goodwill impairment provisions of SFAS No. 142 will not have a material effect on its financial position or results of operations.

In June 2001, the FASB approved Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for the recorded amount or incurs a gain or loss upon settlement. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The company will adopt SFAS No. 143 on January 1, 2003, but has not yet quantified the effects of adopting SFAS No. 143 on its financial position or results of operations.

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In August 2001, the FASB approved SFAS No. 144. SFAS No. 144 supersedes Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS No. 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a segment of a business. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001. The company adopted SFAS No. 144 on January 1, 2002. The adoption of SFAS No. 144 did not have an effect on the company's financial position or results of operations.

The company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), amended by Statement of Financial Accounting Standards No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133" and Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" (all such statements hereinafter referred to as SFAS No. 133) on January 1, 2001. SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

SFAS No. 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivative instruments be reported in net income or other comprehensive income (loss), as appropriate, as the cumulative effect of a change in accounting principle in accordance with APB 20, "Accounting Changes." On January 1, 2001, the company reported a net-of-tax cumulative-effect adjustment of $6.1 million in accumulated other comprehensive loss to recognize at fair value all derivative instruments that are designated as cash-flow hedging instruments, which the company reflected in earnings over the 12 months ended December 31, 2001. The transition to SFAS No. 133 did not have an effect on the company's net income at adoption.

Comprehensive income
Upon the adoption of SFAS No. 133 on January 1, 2001, the company recorded a cumulative-effect adjustment in accumulated other comprehensive income to recognize all derivative instruments designated as hedges at fair value. As of December 31, 2001, the company has recorded unrealized gains and losses on swap agreements in accordance with SFAS No. 133. These amounts are reflected in the Consolidated Statements of Common Stockholders' Equity. For additional information on the adoption of SFAS No. 133, see new accounting pronouncements in Note 1, and Note 3. For the years ended December 31, 2000 and 1999, comprehensive income equaled net income as reported.

NOTE 2
Regulatory Assets and Liabilities
The following table summarizes the individual components of unamortized regulatory assets and liabilities included in the accompanying Consolidated Balance Sheets as of December 31:

	2001	2000
	(In thousands)	
Regulatory assets:		
Deferred income taxes	$ 13,417	$ 263
Long-term debt refinancing costs	6,829	8,125
Plant costs	2,499	2,668

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Postretirement benefit costs	722	833
Other	5,929	7,052
Total regulatory assets	29,396	18,941
Regulatory liabilities:		
Natural gas costs refundable through rate adjustments	27,706	8,772
Taxes refundable to customers	12,318	11,656
Plant decommissioning costs	8,243	7,601
Reserves for regulatory matters	7,132	6,087
Deferred income taxes	5,661	3,554
Other	5,053	1,193
Total regulatory liabilities	66,113	38,863
Net regulatory position	$ (36,717)	$ (19,922)

As of December 31, 2001, substantially all of the company's regulatory assets, other than certain deferred income taxes, are being reflected in rates charged to customers and are being recovered over the next one to 15 years.

If, for any reason, the company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 3
Derivative Instruments
As of December 31, 2001, the company held derivative instruments designated as cash flow hedging instruments. All derivative instruments are recognized on the Consolidated Balance Sheets at fair value.

Hedging activities
The cash flow hedging instruments in place at December 31, 2001, are comprised of natural gas and oil price swap agreements. The objective for holding the natural gas and oil price swap agreements is to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on the company's forecasted sales of natural gas and oil production. The company also entered into an interest rate swap agreement which expired in the fourth quarter of 2001. The objective for holding the interest rate swap agreement was to manage a portion of the company's interest rate risk on the forecasted issuance of fixed-rate debt under Centennial Energy Holdings, Inc.'s (Centennial), a direct wholly owned subsidiary of the company, commercial paper program. The company designated each of the natural gas and oil price swap agreements as a hedge of the forecasted sale of natural gas and oil production and designated the interest rate swap agreement as a hedge of the risk of changes in interest rates on the company's forecasted issuances of fixed-rate debt under Centennial's commercial paper program.

The company's policy allows the use of derivative instruments as part of an overall energy price and interest rate risk management program to efficiently manage and minimize commodity price and interest rate risk. The company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions and the company has procedures in place to monitor compliance with its policies. The company is exposed to credit-related losses in relation to hedged derivative instruments in the event of nonperformance by counterparties. The company has policies and procedures, which management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings, credit exposure limitations, settlement of natural gas and oil price swap agreements monthly and settlement of interest rate swap agreements within 90 days. Accordingly, the company does not anticipate any material effect to its financial position or results of operations as a

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result of nonperformance by counterparties.

Upon the adoption of SFAS No. 133, the company recorded the fair market value of the natural gas and oil price swap agreements on the company's Consolidated Balance Sheets. On an ongoing basis, the company adjusts its balance sheet to reflect the current fair market value of its swap agreements. The related gains or losses on these agreements are recorded in common stockholders' equity as a component of other comprehensive income (loss). At the date the underlying transaction occurs, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the year ended December 31, 2001, the company recognized the ineffectiveness of all cash flow hedges, which is included in operating revenues and interest expense for the natural gas and oil price swap agreements and the interest rate swap agreement, respectively. For the year ended December 31, 2001, the amount of ineffectiveness recognized was immaterial. For the year ended December 31, 2001, the company did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness and there were no reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2001, the maximum length of time over which the company is hedging its exposure to the variability in future cash flows for forecasted transactions is 12 months and the company estimates that net gains of approximately $2.2 million will be reclassified from accumulated other comprehensive income into earnings, subject to changes in natural gas and oil market prices, within the 12 months between January 1, 2002 and December 31, 2002, as the hedged transactions affect earnings.

In the event a derivative instrument does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; or if the derivative instrument expires or is sold, terminated, or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting will be discontinued, and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income (loss) would be recognized immediately in earnings. The company's policy requires approval to terminate a hedge agreement prior to its original maturity.

Energy marketing
The company had entered into other derivative instruments that were not designated as hedges in its energy marketing operations. In the third quarter of 2001, the company sold the vast majority of its energy marketing operations. The derivative instruments entered into by these operations prior to the sale in the third quarter of 2001 were natural gas forward purchase and sale commitments. These commitments involved the purchase and sale of natural gas and related delivery of such commodity. These operations sought to match natural gas purchases and sales so that a margin was obtained on the transportation of such commodity as distinguished from earning a margin on changes in market prices. The net change in fair value representing unrealized gains and losses resulting from changes

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in market prices on these derivative instruments was reflected as operating revenues or purchased natural gas sold. Net unrealized gains and losses on these derivative instruments were not material for the years ended December 31, 2001, 2000 and 1999.

NOTE 4
Fair Value of Other Financial Instruments
The estimated fair value of the company's long-term debt and preferred stock subject to mandatory redemption is based on quoted market prices of the same or similar issues. The estimated fair value of the company's long-term debt and preferred stock subject to mandatory redemption at December 31 is as follows:

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$ 794,794	$ 894,652	$ 747,761	$772,127
Preferred stock subject to mandatory redemption	$ 1,400	$ 940	$ 1,500	$ 927

The fair value of other financial instruments for which estimated fair value has not been presented is not materially different than the related carrying amount.

NOTE 5
Short-term Borrowings
The company has unsecured short-term lines of credit from a number of banks totaling $110 million at December 31, 2001. These line of credit agreements provide for bank borrowings against the lines and/or support for commercial paper issues. The agreements provide for commitment fees at varying rates. There were no amounts outstanding on the short-term lines of credit at December 31, 2001. The amount outstanding on the short-term lines of credit was $8 million at December 31, 2000. The weighted average interest rate for borrowings outstanding at December 31, 2000, was 6.6 percent.

NOTE 6
Long-term Debt and Indenture Provisions
Long-term debt outstanding at December 31 is as follows:

	2001	2000
	(In thousands)	
First mortgage bonds and notes:		
Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022	$ 20,850	$ 20,850
Secured Medium-Term Notes, Series A at a weighted average rate of 7.59%, due on dates ranging from October 1, 2004 to April 1, 2012	110,000	110,000
Total first mortgage bonds and notes	130,850	130,850
Senior notes at a weighted average rate of 7.34%, due on dates ranging from July 31, 2002 to October 30, 2018	405,200	294,300
Commercial paper at a weighted average rate of 2.43%, supported by a revolving credit agreement	219,700	261,350
Revolving line of credit, 4.75%, due December 31, 2003	25,000	46,302

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Term credit agreements at a weighted average rate of 7.38%, due on dates ranging from February 1, 2002 through December 1, 2013	11,769	12,731
Pollution control note obligation, 6.20%, due March 1, 2004	2,500	2,800
Discount	(225)	(572)
Total long-term debt	794,794	747,761
Less current maturities	11,085	19,595
Net long-term debt	$ 783,709	$ 728,166

Centennial has a revolving credit agreement with various banks that supports Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreement at December 31, 2001. Under the commercial paper program, $219.7 million and $261.4 million were outstanding at December 31, 2001 and 2000, respectively. The commercial paper borrowings are classified as long term as Centennial intends to refinance these borrowings on a long-term basis through continued commercial paper borrowings and as further supported by the revolving credit agreement, which allows for subsequent borrowings up to a term of one year. Centennial intends to renew this existing credit agreement, which expires September 27, 2002, on an annual basis.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $300 million. Under the master shelf agreement, $210 million was outstanding at December 31, 2001, and $150 million was outstanding at December 31, 2000. The amount outstanding is included in senior notes in the preceding long-term debt table.

Under a revolving line of credit, the company has $40 million available as of December 31, 2001. The amount outstanding under the revolving line of credit was $25.0 million at December 31, 2001. At December 31, 2000, the company had $46.3 million outstanding under revolving lines of credit.

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2001, aggregate $11.1 million in 2002; $266.8 million in 2003; $21.9 million in 2004; $70.2 million in 2005; $85.2 million in 2006 and $339.6 million thereafter.

Substantially all of the company's electric and natural gas distribution properties, with certain exceptions, are subject to the lien of its Indenture of Mortgage. Under the terms and conditions of the Indenture, the company could have issued approximately $305 million of additional first mortgage bonds at December 31, 2001. Certain other debt instruments of the company contain restrictive covenants, all of which the company is in compliance with at December 31, 2001.

NOTE 7
Preferred Stocks
Preferred stocks at December 31 are as follows:

	2001	2000
	(Dollars in thousands)	
Authorized:		
Preferred -- 500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A -- 1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference -- 500,000 shares, cumulative, without par		

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value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption --		
Preferred --		
5.10% Series -- 14,000 shares in 2001 and 15,000 shares in 2000	$ 1,400	$ 1,500
Other preferred stock --		
4.50% Series -- 100,000 shares	10,000	10,000
4.70% Series -- 50,000 shares	5,000	5,000
	15,000	15,000
Total preferred stocks	16,400	16,500
Less sinking fund requirements	100	100
Net preferred stocks	$ 16,300	$ 16,400

The preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the company with certain limitations on 30 days notice on any quarterly dividend date on certain series of preferred stock.

The company is obligated to make annual sinking fund contributions to retire the 5.10% Series preferred stock. The redemption prices and sinking fund requirements, where applicable, are summarized below:

Series	Redemption Price (a)	Sinking Fund Shares	Sinking Fund Price (a)
Preferred stocks:			
4.50%	$105 (b)	---	---
4.70%	$102 (b)	---	---
5.10%	$102	1,000 (c)	$100

(a) Plus accrued dividends.
(b) These series are redeemable at the sole discretion of the company.
(c) Annually on December 1, if tendered.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The aggregate annual sinking fund amount applicable to preferred stock subject to mandatory redemption is $100,000 for each of the five years following December 31, 2001, and $900,000 thereafter.

NOTE 8
Common Stock
At the Annual Meeting of Stockholders held in April 1999, the company's common stockholders approved an amendment to the Certificate of Incorporation increasing the authorized number of common shares from 75 million shares to 150 million shares and reducing the par value of the common stock from $3.33 per share to $1.00 per share.

The company's Automatic Dividend Reinvestment and Stock Purchase Plan (Stock Purchase Plan) provides participants the opportunity to invest all or a portion of their cash dividends in shares of the company's common stock and to make optional cash payments for the same purpose. Holders of all classes of the company's capital stock, legal residents in any of the 50 states, and beneficial owners, whose shares are held by brokers or other nominees through participation by their brokers or nominees, are eligible to participate in the Stock Purchase Plan. The company's 401(k) Retirement Plan (K-Plan), is funded with the company's common stock. Since January 1, 1999, the Stock Purchase Plan and K-Plan have been funded primarily by the purchase of shares of common stock on the open market, except from January 1, 1999 through March 31, 1999, when shares of authorized but unissued common stock were used to fund the Stock Purchase Plan. At December 31, 2001, there were 8.1 million shares of common stock reserved for original issuance under the Stock Purchase

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Plan and K-Plan.

In November 1998, the company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for one one-thousandth of a share of Series B Preference Stock of the company, without par value, at an exercise price of $125 per one one-thousandth, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.01 per right, at the company's option at any time until any acquiring person has acquired 15 percent or more of the company's common stock.

The company has stock option plans for directors, key employees and employees, which grant options to purchase shares of the company's stock. The company accounts for these option plans in accordance with APB Opinion No. 25 under which no compensation expense has been recognized. The option exercise price is the market value of the stock on the date of grant. Options granted to the key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the company, and expire 10 years after the date of grant. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire 10 years after the date of grant. In addition, the company has granted restricted stock awards under a long-term incentive plan, deferred compensation agreements and a restricted stock agreement totaling 350,392 shares, 348,021 shares and 105,250 shares in 2001, 2000 and 1999, respectively. The restricted stock awards granted vest to the participants at various times ranging from two years to nine years from date of issuance but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the company. The weighted average grant date fair value of the restricted stock grants was $31.55, $20.81 and $22.91 in 2001, 2000 and 1999, respectively. Compensation expense recognized for restricted stock grants was $4.5 million, $1.6 million and $722,000 in 2001, 2000 and 1999, respectively. Under the stock option plans and long-term incentive plan, the company is authorized to grant options and restricted stock for up to 9.8 million shares of common stock and has granted options and restricted stock on 4.8 million shares through December 31, 2001.

Had the company recorded compensation expense for the fair value of options granted consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," net income would have been reduced on a pro forma basis by $3.8 million in 2001, $529,000 in 2000, and $498,000 in 1999. On a pro forma basis, basic and diluted earnings per share for 2001 would have been reduced by $.06. On a pro forma basis, there would have been no effect on basic earnings per share for 2000, and diluted earnings per share would have been reduced by $.01. On a pro forma basis, basic and diluted earnings per share for 1999 would have been reduced by $.01.

A summary of the status of the stock option plans at December 31, 2001, 2000 and 1999, and changes during the years then ended are as follows:

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	2001		2000		1999	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	1,224,959	$20.61	1,427,262	$19.46	1,516,808	$19.17
Granted	2,693,120	30.14	74,000	20.54	22,500	23.31
Forfeited	(74,282)	27.24	(84,135)	21.18	(57,966)	20.38
Exercised	(371,590)	20.23	(192,168)	11.84	(54,080)	11.95
Balance at end of year	3,472,207	27.90	1,224,959	20.61	1,427,262	19.46
Exercisable at end of year	770,142	$21.41	129,763	$18.11	301,681	$13.89

Summarized information about stock options outstanding and exercisable as of December 31, 2001, is as follows:

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$10.50 - 17.50	41,966	3.7	$13.36	41,966	$13.36
17.51 - 24.50	789,371	6.3	21.15	698,176	21.16
24.51 - 31.50	2,490,240	9.2	29.74	---	---
31.51 - 38.55	150,630	9.2	36.86	30,000	38.55
	3,472,207			770,142	

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options are as follows:

	2001	2000	1999
Weighted average fair value of options at grant date	$ 7.38	$ 5.07	$ 4.82
Weighted average risk-free interest rate	5.19%	6.76%	5.98%
Weighted average expected price volatility	26.05%	23.55%	22.03%
Weighted average expected dividend yield	3.53%	3.84%	4.22%
Expected life in years	7	7	7

NOTE 9
Income Taxes
Income tax expense is summarized as follows:

Years ended December 31,	2001	2000	1999
		(In thousands)	
Current:			
Federal	$ 66,211	$ 27,865	$ 29,574
State	11,160	5,188	3,874
Foreign	(44)	67	158
	77,327	33,120	33,606
Deferred:			

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Income taxes --			
Federal	16,972	29,323	12,902
State	4,773	8,060	3,690
Investment tax credit	(731)	(853)	(888)
	21,014	36,530	15,704
Total income tax expense	$ 98,341	$ 69,650	$ 49,310

Components of deferred tax assets and deferred tax liabilities recognized in the company's Consolidated Balance Sheets at December 31 are as follows:

	2001	2000
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 21,000	$ 7,650
Accrued pension costs	9,349	10,325
Accrued land reclamation	1,648	1,941
Deferred investment tax credit	1,413	1,697
Other	21,691	18,213
Total deferred tax assets	55,101	39,826
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	302,103	264,635
Basis differences on natural gas and oil producing properties	61,684	36,763
Regulatory matters	5,661	3,554
Other	9,092	7,826
Total deferred tax liabilities	378,540	312,778
Net deferred income tax liability	$ (323,439)	$ (272,952)

The following table reconciles the change in the net deferred income tax liability from December 31, 2000, to December 31, 2001, to the deferred income tax expense included in the Consolidated Statements of Income:

	2001
	(In thousands)
Net change in deferred income tax liability from the preceding table	$ 50,487
Deferred taxes associated with acquisitions	(29,807)
Other	334
Deferred income tax expense for the period	$ 21,014

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference are as follows:

Years ended December 31,	2001		2000		1999	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	$ 88,966	35.0	$ 63,237	35.0	$ 46,686	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	11,311	4.5	8,044	4.4	5,921	4.4
Investment tax credit amortization	(731)	(.3)	(853)	(.5)	(888)	(.6)
Depletion allowance	(1,820)	(.7)	(1,631)	(.9)	(1,300)	(1.0)
Other items	615	.2	853	.5	(1,109)	(.8)

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Total income tax expense	$ 98,341	38.7	$ 69,650	38.5	$ 49,310	37.0

NOTE 10
Business Segment Data
The company's reportable segments are those that are based on the company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation.

The company's operations are conducted through six business segments. Substantially all of the company's operations are located within the United States. The electric segment generates, transmits and distributes electricity and the natural gas distribution segment distributes natural gas. These operations also supply related value-added products and services in the northern Great Plains. The utility services segment consists of a diversified infrastructure company specializing in engineering, design and build capability for electric, gas and telecommunication utility construction, as well as industrial and commercial electrical, exterior lighting and traffic signalization throughout most of the United States. Utility services provides related specialty equipment manufacturing sales and rental services. The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. Energy-related marketing and management services as well as cable and pipeline locating services also are provided. The pipeline and energy services segment includes investments in domestic and international growth opportunities. The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration and production activities primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico. The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and other related construction materials, including ready-mixed concrete, cement and asphalt, as well as value-added products and services in the north central and western United States, including Alaska and Hawaii.

In 2001, the company sold its coal operations to Westmoreland Coal Company for $28.2 million in cash, including final settlement cost adjustments. The sale of the coal operations was effective April 30, 2001. Included in the sale were active coal mines in North Dakota and Montana, coal sales agreements, reserves and mining equipment, and certain development rights at the former Gascoyne Mine site in North Dakota. The company retains ownership of coal reserves and leases at its former Gascoyne Mine site. Including final settlement cost adjustments, the company recorded a gain of $10.3 million ($6.2 million after-tax) included in other income - net from the sale in 2001.

On August 30, 2001, MDU Resources International, Inc. (MDU International), a wholly owned subsidiary of the company, through an indirect wholly owned Brazilian subsidiary, entered into a joint venture agreement with a Brazilian firm under which the parties have formed MPX Holdings, Ltda. (MPX) to develop electric generation and transmission, steam generation, power equipment, coal mining and construction materials projects in Brazil. MDU International has a 49 percent interest in MPX. MPX is currently developing, through a wholly owned subsidiary, and has under construction a 200-megawatt natural gas-fired power plant (Project) in the Brazilian state of Ceara. The Project is expected to enter commercial operation in the second quarter of 2002. MPX expects to enter into an agreement with Petrobras, the state-controlled energy company, under which Petrobras would purchase all of the capacity and market all of the Project's energy. Petrobras would also supply natural gas to the Project when energy is dispatched. The Project has a total estimated construction cost of approximately $96 million. At December 31, 2001, MDU International's investment in the Project was approximately $23.8 million. In addition, the company's subsidiaries had guaranteed Project obligations and loans for approximately $17.3 million as of December 31, 2001.

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Segment information follows the same accounting policies as described in the Summary of Significant Accounting Policies. Segment information included in the accompanying Consolidated Balance Sheets as of December 31 and included in the Consolidated Statements of Income for the years then ended is as follows:

	2001	2000	1999
		(In thousands)	
External operating revenues:			
Electric	$ 168,837	$ 161,621	$ 154,869
Natural gas distribution	255,389	233,051	157,692
Utility services	364,746	169,382	99,917
Pipeline and energy services	479,108	579,207	334,188
Natural gas and oil production	148,653	99,014	63,238
Construction materials and mining	801,883	617,564	455,939
Total external operating revenues	$ 2,218,616	$ 1,859,839	$ 1,265,843
Intersegment operating revenues:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	4	---	---
Pipeline and energy services	52,006	57,641	49,344
Natural gas and oil production	61,178	39,302	15,156
Construction materials and mining(a)	5,016	13,832	13,966
Intersegment eliminations	(113,188)	(96,943)	(64,500)
Total intersegment operating revenues(a)	$ 5,016	$ 13,832	$ 13,966
Depreciation, depletion and amortization:			
Electric	$ 19,488	$ 19,115	$ 18,375
Natural gas distribution	9,337	8,399	7,348
Utility services	8,395	4,912	2,591
Pipeline and energy services	14,341	15,301	8,248
Natural gas and oil production	41,690	27,008	19,248
Construction materials and mining	46,666	36,153	26,008
Total depreciation, depletion and amortization	$ 139,917	$ 110,888	$ 81,818
Interest expense:			
Electric	$ 8,531	$ 10,007	$ 9,692
Natural gas distribution	3,727	4,142	3,614
Utility services	3,807	2,492	812
Pipeline and energy services	9,136	10,029	7,281
Natural gas and oil production	1,359	5,160	3,405
Construction materials and mining	19,339	16,415	11,202
Intersegment eliminations	---	(212)	---
Total interest expense	$ 45,899	$ 48,033	$ 36,006
Income taxes:			
Electric	$ 10,511	$ 10,048	$ 8,678
Natural gas distribution	1,067	3,544	1,443
Utility services	9,131	6,027	4,323
Pipeline and energy services	11,633	9,214	13,356
Natural gas and oil production	40,486	23,906	10,032
Construction materials and mining	25,513	16,911	11,478
Total income taxes	$ 98,341	$ 69,650	$ 49,310

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Earnings on common stock:			
Electric	$ 18,717	$ 17,733	$ 15,973
Natural gas distribution	677	4,741	3,192
Utility services	12,910	8,607	6,505
Pipeline and energy services	16,406	10,494	20,972
Natural gas and oil production	63,178	38,574	16,207
Construction materials and mining	43,199	30,113	20,459
Total earnings on common stock	$ 155,087	$ 110,262	$ 83,308
Capital expenditures:			
Electric	$ 14,373	$ 15,788	$ 18,218
Natural gas distribution	14,685	21,336	9,246
Utility services	70,232	42,633	16,052
Pipeline and energy services	51,054	69,006	35,123
Natural gas and oil production	118,719	173,441	64,294
Construction materials and mining	170,585	218,716	105,098
Net proceeds from sale or disposition of property	(51,641)	(11,000)	(16,660)
Total net capital expenditures	$ 388,007	$ 529,920	$ 231,371
Identifiable assets:			
Electric(b)	$ 291,229	$ 305,099	$ 307,417
Natural gas distribution(b)	182,705	192,854	131,294
Utility services	239,069	123,451	67,755
Pipeline and energy services	346,879	362,592	302,587
Natural gas and oil production	476,105	410,207	255,416
Construction materials and mining	1,035,929	874,299	655,499
Corporate assets(c)	51,155	44,457	46,335
Total identifiable assets	$ 2,623,071	$ 2,312,959	$ 1,766,303
Property, plant and equipment:			
Electric (b)	$ 597,080	$ 589,700	$ 581,090
Natural gas distribution (b)	238,566	227,742	185,797
Utility services	59,190	39,865	21,876
Pipeline and energy services	410,049	369,834	308,409
Natural gas and oil production	630,826	513,419	343,157
Construction materials and mining	820,984	755,563	601,952
Less accumulated depreciation, depletion and amortization	947,377	895,109	794,105
Net property, plant and equipment	$ 1,809,318	$ 1,601,014	$ 1,248,176

(a) In accordance with the provision of SFAS No. 71, intercompany coal sales are not eliminated.
(b) Includes, in the case of electric and natural gas distribution property, allocations of common utility property.
(c) Corporate assets consist of assets not directly assignable to a business segment (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).

Capital expenditures for 2001, 2000 and 1999, related to acquisitions, in the preceding table include the following noncash transactions: issuance of the company's equity securities of $57.4 million in 2001; issuance of the company's equity securities and the conversion of a note receivable to purchase consideration of $132.1 million in 2000; and issuance of the company's equity securities of $77.5 million in 1999.

NOTE 11
Acquisitions

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In 2001, the company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Minnesota and Oregon; utility services businesses based in Missouri and Oregon; and an energy services company specializing in cable and pipeline locating and tracking systems. The total purchase consideration for these businesses, consisting of the company's common stock and cash, was $170.1 million.

In 2000, the company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses with operations in Alaska, California, Montana and Oregon; a coalbed natural gas development operation based in Colorado with related oil and gas leases and properties in Montana and Wyoming; utility services businesses based in California, Colorado, Montana and Ohio; a natural gas distribution business serving southeastern North Dakota and western Minnesota; and an energy services company based in Texas. The total purchase consideration for these businesses, consisting of the company's common stock, cash and the conversion of a note receivable to purchase consideration, was $286.0 million.

On April 1, 2000, Fidelity Exploration & Production Company (Fidelity), an indirect wholly owned subsidiary of the company, purchased substantially all of the assets of Preston Reynolds & Co., Inc. (Preston), a coalbed natural gas development operation, as previously discussed. Pursuant to the asset purchase and sale agreement, Preston may, but is not obligated to purchase, acquire and own an undivided 25 percent working interest (Seller's Option Interest) in certain oil and gas leases or properties acquired and/or generated by Fidelity. The Seller's Option Interest commences April 1, 2002 and terminates six months thereafter and requires Preston to pay Fidelity 25 percent of its capital investment, during the two year period subsequent to April 1, 2000, in the oil and gas leases or properties. Fidelity has the right, but not the obligation, to purchase Seller's Option Interest from Preston for an amount as specified in the agreement.

In 1999, the company acquired a number of businesses, none of which was individually material, including construction materials and mining companies with operations in California, Montana, Oregon and Wyoming; and utility services companies based in Montana and Oregon. The total purchase consideration for these businesses, consisting of the company's common stock and cash, was $81.9 million.

The above acquisitions were accounted for under the purchase method of accounting and accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. Final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date on certain of the above acquisitions made in 2001. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented as such acquisitions were not material to the company's financial position or results of operations.

NOTE 12
Employee Benefit Plans
The company has noncontributory defined benefit pension plans and other postretirement benefit plans. Changes in benefit obligation and plan assets for the years ended December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at				

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beginning of year	$200,880	$180,997	$ 69,467	$ 65,939
Service cost	4,716	4,561	1,376	1,307
Interest cost	14,498	14,174	4,691	4,946
Plan participants' contributions	---	---	866	677
Amendments	(1,342)	7,111	---	---
Actuarial (gain) loss	8,128	9,535	(2,109)	928
Divestiture*	(10,017)	---	(2,871)	---
Benefits paid	(12,817)	(15,498)	(4,401)	(4,330)
Benefit obligation at end of year	204,046	200,880	67,019	69,467
Change in plan assets:				
Fair value of plan assets at beginning of year	261,864	276,459	47,046	47,147
Actual return on plan assets	(13,828)	875	(2,235)	(1,078)
Employer contribution	337	28	3,899	4,630
Plan participants' contributions	---	---	866	677
Divestiture*	(10,889)	---	---	---
Benefits paid	(12,817)	(15,498)	(4,401)	(4,330)
Fair value of plan assets at end of year	224,667	261,864	45,175	47,046
Funded status	20,621	60,984	(21,844)	(22,421)
Unrecognized actuarial gain	(26,170)	(76,417)	(10,799)	(15,228)
Unrecognized prior service cost	10,278	16,271	---	---
Unrecognized net transition obligation (asset)	(2,195)	(3,387)	23,665	28,532
Prepaid (accrued) benefit cost	$ 2,534	$ (2,549)	$ (8,978)	$ (9,117)

* See Note 10 for more information on the sale of the company's coal operations.

Weighted average assumptions for the company's pension and other postretirement benefit plans as of December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
Discount rate	7.25%	7.50%	7.25%	7.50%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%

Health care rate assumptions for the company's other postretirement benefit plans as of December 31 are as follows:

	2001	2000
Health care trend rate	6.00%-7.00%	6.00%-7.50%
Health care cost trend rate - ultimate	5.00%-6.00%	5.00%-6.00%
Year in which ultimate trend rate achieved	1999-2004	1999-2004

Components of net periodic benefit cost for the company's pension and other postretirement benefit plans are as follows:

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2001	2000	1999	2001	2000	1999
			(In thousands)			
Components of net periodic						

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benefit cost:						
Service cost	$ 4,716	$ 4,561	$ 4,894	$ 1,376	$ 1,307	$ 1,451
Interest cost	14,498	14,174	12,573	4,691	4,946	4,720
Expected return on assets	(20,672)	(19,927)	(17,489)	(3,619)	(3,267)	(2,807)
Amortization of prior service cost	1,247	1,047	842	---	---	---
Recognized net actuarial gain	(2,687)	(2,907)	(995)	(930)	(799)	(200)
Settlement (gain) loss	(884)	(700)	---	15	---	---
Amortization of net transition obligation (asset)	(965)	(997)	(997)	2,227	2,378	2,377
Net periodic benefit cost (income)	(4,747)	(4,749)	(1,172)	3,760	4,565	5,541
Less amount capitalized	(391)	(397)	(87)	329	369	463
Net periodic benefit expense (income)	$ (4,356)	$ (4,352)	$(1,085)	$ 3,431	$ 4,196	$ 5,078

The company's other postretirement benefit plans include health care and life insurance benefits. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have the following effects at December 31, 2001:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 260	$ (229)
Effect on postretirement benefit obligation	$ 3,326	$ (2,906)

In addition to company-sponsored plans, certain employees are covered under multi-employer defined benefit plans administered by a union. Amounts contributed to the multi-employer plans were $19.9 million, $10.6 million and $6.8 million in 2001, 2000 and 1999, respectively.

The company has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that provides for defined benefit payments upon the employee's retirement or to their beneficiaries upon death for a 15-year period. Investments consist of life insurance carried on plan participants, which is payable to the company upon the employee's death. The cost of these benefits was $4.3 million, $3.5 million and $3.3 million in 2001, 2000 and 1999, respectively.

The company sponsors various defined contribution plans for eligible employees. Costs incurred by the company under these plans were $7.2 million in 2001, $6.1 million in 2000 and $4.4 million in 1999. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 13
Jointly Owned Facilities

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The consolidated financial statements include the company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The company's share of the Big Stone Station and Coyote Station operating expenses is reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2001	2000
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 50,053	$ 50,029
Less accumulated depreciation	32,956	31,381
	$ 17,097	$ 18,648
Coyote Station:		
Utility plant in service	$ 122,436	$ 122,111
Less accumulated depreciation	67,414	63,741
	$ 55,022	$ 58,370

NOTE 14
Regulatory Matters and Revenues Subject To Refund
In December 1999, Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the company, filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. On May 9, 2001, the Administrative Law Judge issued an Initial Decision on Williston Basin's natural gas rate change application, which matter is currently pending before and subject to revision by the FERC.

Reserves have been provided for a portion of the revenues that have been collected subject to refund with respect to the pending regulatory proceeding. Williston Basin, in the fourth quarter of 2000, determined that reserves it had previously established for certain regulatory proceedings, prior to the proceeding filed in 1999, exceeded its expected refund obligation and, accordingly, reversed reserves and recognized in income $6.7 million after-tax. Williston Basin, in the second quarter of 1999, determined that reserves it had previously established in relation to a 1992 general natural gas rate change application and the 1995 general rate increase application exceeded its expected refund obligation and, accordingly, reversed reserves and recognized in income $4.4 million after-tax. Williston Basin believes that its remaining reserves are adequate based on its assessment of the ultimate outcome of the application filed in December 1999.

NOTE 15
Commitments and Contingencies
Litigation
In March 1997, 11 natural gas producers filed suit in North Dakota Southwest Judicial District Court (North Dakota District Court) against Williston Basin and the company. The natural gas producers had processing agreements with Koch Hydrocarbon Company (Koch). Williston Basin and the company had natural gas purchase contracts with Koch. The natural gas producers alleged they were entitled to damages for the breach of Williston Basin's and the company's contracts with Koch although no specific damages were stated. A similar suit was filed by Apache Corporation (Apache) and Snyder Oil Corporation (Snyder) in North Dakota Northwest Judicial District Court in December 1993. The North Dakota Supreme Court in December 1999 affirmed the North Dakota Northwest Judicial District Court decision dismissing Apache's and Snyder's claims against Williston Basin and the company. Based in part upon the decision of the North Dakota Supreme Court affirming the dismissal of the

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claims brought by Apache and Snyder, Williston Basin and the company filed motions for summary judgment to dismiss the claims of the 11 natural gas producers. The motions for summary judgment were granted by the North Dakota District Court in July 2000. On March 5, 2001, the North Dakota District Court entered a final judgment on the July 2000 order granting the motions for summary judgment. On May 4, 2001, the 11 natural gas producers appealed the North Dakota District Court's decision by filing a Notice of Appeal with the North Dakota Supreme Court. Oral argument was held before the North Dakota Supreme Court on December 12, 2001. Williston Basin and the company are awaiting a decision from the North Dakota Supreme Court.

In July 1996, Jack J. Grynberg (Grynberg) filed suit in United States District Court for the District of Columbia (U.S. District Court) against Williston Basin and over 70 other natural gas pipeline companies. Grynberg, acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content or volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. In March 1997, the U.S. District Court dismissed the suit without prejudice and the dismissal was affirmed by the United States Court of Appeals for the D.C. Circuit in October 1998. In June 1997, Grynberg filed a similar Federal False Claims Act suit against Williston Basin and Montana-Dakota Utilities Co. (Montana-Dakota) and filed over 70 other separate similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. In April 1999, the United States Department of Justice decided not to intervene in these cases. In response to a motion filed by Grynberg, the Judicial Panel on Multidistrict Litigation consolidated all of these cases in the Federal District Court of Wyoming (Federal District Court). Oral argument on motions to dismiss was held before the Federal District Court in March 2000. On May 18, 2001, the Federal District Court denied Williston Basin's and Montana-Dakota's motion to dismiss. The matter is currently pending.

The Quinque Operating Company (Quinque), on behalf of itself and subclasses of gas producers, royalty owners and state taxing authorities, instituted a legal proceeding in State District Court for Stevens County, Kansas, (State District Court) against over 200 natural gas transmission companies and producers, gatherers, and processors of natural gas, including Williston Basin and Montana-Dakota. The complaint, which was served on Williston Basin and Montana-Dakota in September 1999, contains allegations of improper measurement of the heating content and volume of all natural gas measured by the defendants other than natural gas produced from federal lands. In response to a motion filed by the defendants in this suit, the Judicial Panel on Multidistrict Litigation transferred the suit to the Federal District Court for inclusion in the pretrial proceedings of the Grynberg suit. Upon motion of plaintiffs, the case has been remanded to State District Court. On September 12, 2001, the defendants in this suit filed a motion to dismiss with the State District Court. The matter is currently pending.

Williston Basin and Montana-Dakota believe the claims of Grynberg and Quinque are without merit and intend to vigorously contest these suits.

The company is also involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that there is no pending legal proceeding against or involving the company, except those discussed above, for which the outcome is likely to have a material adverse effect upon the company's financial position or results of operations.

Environmental matters
In December 2000, Morse Bros., Inc. (MBI), an indirect wholly owned subsidiary of the company, was named by the United States Environmental Protection Agency (EPA) as a Potentially Responsible Party in connection with the cleanup of a commercial property site, now owned by MBI, and part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants

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responsible parties to share in the cleanup of sediment contamination in the Willamette River. Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon State Department of Environmental Quality and other information available, MBI does not believe it is a Responsible Party. In addition, MBI intends to seek indemnity for any and all liabilities incurred in relation to the above matters from Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, pursuant to the terms of their sale agreement.

Operating leases
The company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2001, are $17.4 million in 2002, $14.3 million in 2003, $11.0 million in 2004, $8.3 million in 2005, $6.3 million in 2006 and $25.1 million thereafter. Rent expense related to operating leases was approximately $31.5 million, $23.7 million and $15.4 million for the years ended December 31, 2001, 2000 and 1999, respectively.

Purchase commitments
The company has entered into various commitments, largely purchased-power, coal and natural gas supply, and natural gas transportation contracts. These commitments range from one to 17 years. The commitments under these contracts as of December 31, 2001, are $108.8 million in 2002, $53.1 million in 2003, $46.9 million in 2004, $39.2 million in 2005, $33.2 million in 2006 and $126.5 million thereafter. These commitments are not reflected in the company's consolidated financial statements.

Guarantees
The company has certain financial guarantees largely consisting of guarantees on obligations and loans on the natural gas-fired power plant project in the Brazilian state of Ceara. For more information on the natural gas-fired power plant project see Note 10. These guarantees, as of December 31, 2001, are approximately $20.6 million for 2002. These guarantees are not reflected in the consolidated financial statements.

NOTE 16
Quarterly Data (Unaudited)
The following unaudited information shows selected items by quarter for the years 2001 and 2000:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2001				
Operating revenues	$ 641,248	$ 546,418	$ 551,680	$ 484,286
Operating expenses	577,727	476,071	458,441	438,125
Operating income	63,521	70,347	93,239	46,161
Net income	32,687	43,417	50,746	28,999
Earnings per common share:				
Basic	.50	.64	.75	.42
Diluted	.49	.63	.74	.42
Weighted average common shares outstanding:				
Basic	65,405	67,264	67,650	68,729
Diluted	65,979	68,376	68,127	69,126
2000				
Operating revenues	$371,989	$362,979	$530,834	$607,869
Operating expenses	342,559	321,900	454,811	537,414
Operating income	29,430	41,079	76,023	70,455
Net income	13,364	21,126	39,992	36,546
Earnings per common share:				

Name of Respondent	This Report is:	Date of Report	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2001	Dec 31, 2001

NOTES TO FINANCIAL STATEMENTS (Continued)

Basic	.23	.35	.63	.57
Diluted	.23	.35	.63	.56
Weighted average common shares outstanding:				
Basic	57,051	59,987	62,975	64,289
Diluted	57,188	60,212	63,345	64,817

Certain company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

NOTE 17
Natural Gas and Oil Activities (Unaudited)
Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties with potential development opportunities, exploratory drilling and the operation and development of natural gas production properties. Fidelity shares revenues and expenses from the development of specified properties located primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico in proportion to its interests.

Fidelity owns in fee or holds natural gas leases for the properties it operates in Colorado, Montana, North Dakota and Wyoming. These rights are in the Bonny Field located in eastern Colorado, the Cedar Creek Anticline in southeastern Montana and southwestern North Dakota, the Bowdoin area located in north-central Montana and in the Powder River Basin of Wyoming and Montana.

The information that follows includes the company's proportionate share of all its natural gas and oil interests held by Fidelity.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to natural gas and oil producing activities at December 31:

	2001	2000	1999
		(In thousands)	
Subject to amortization	$ 506,155	$ 416,881	$ 319,448
Not subject to amortization	122,354	94,856	23,464
Total capitalized costs	628,509	511,737	342,912
Less accumulated depreciation, depletion and amortization	195,469	155,198	129,211
Net capitalized costs	$ 433,040	$ 356,539	$ 213,701

Capital expenditures, including those not subject to amortization, related to natural gas and oil producing activities are as follows:

Years ended December 31,	2001	2000	1999
		(In thousands)	
Acquisitions	$ 1,695	$ 68,858	$ 30,842
Exploration	13,938	34,839	11,010
Development	102,670	69,051	21,822
Total capital expenditures	$ 118,303	$ 172,748	$ 63,674

The following summary reflects income resulting from the company's operations of natural gas and oil producing activities, excluding corporate overhead and financing costs:

Years ended December 31,	2001	2000	1999
		(In thousands)	

Name of Respondent	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.		12/31/2001	Dec 31, 2001

NOTES TO FINANCIAL STATEMENTS (Continued)

Revenues	$ 203,727	$ 128,217	$ 75,327
Production costs	47,045	33,919	25,402
Depreciation, depletion and amortization	41,223	26,739	19,136
Pretax income	115,459	67,559	30,789
Income tax expense	45,245	25,835	11,815
Results of operations for producing activities	$ 70,214	$ 41,724	$ 18,974

The following table summarizes the company's estimated quantities of proved natural gas and oil reserves at December 31, 2001, 2000 and 1999, and reconciles the changes between these dates. Estimates of economically recoverable natural gas and oil reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

	2001		2000		1999	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
	(In thousands of Mcf/barrels)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	309,800	15,100	268,900	14,700	243,600	11,500
Production	(40,600)	(2,000)	(29,200)	(1,900)	(24,700)	(1,800)
Extensions and discoveries	66,400	2,000	51,300	1,600	21,800	800
Purchases of proved reserves	1,000	100	23,200	100	38,200	700
Sales of reserves in place	---	---	---	(100)	(9,300)	(400)
Revisions to previous estimates due to improved secondary recovery techniques and/or changed economic conditions	(12,500)	2,300	(4,400)	700	(700)	3,900
Balance at end of year	324,100	17,500	309,800	15,100	268,900	14,700
Proved developed reserves:						
January 1, 1999	193,000	10,700				
December 31, 1999	213,400	13,300				
December 31, 2000	263,400	14,200				
December 31, 2001	291,300	17,100				

All of the company's interests in natural gas and oil reserves are located in the United States and in the Gulf of Mexico.

The standardized measure of the company's estimated discounted future net cash flows of total proved reserves associated with its various natural gas and oil interests at December 31 is as follows:

	2001	2000	1999
	(In thousands)		
Future net cash flows before income taxes	$ 548,000	$ 2,349,500	$ 492,000
Future income tax expense	112,000	827,000	131,500
Future net cash flows	436,000	1,522,500	360,500

Name of Respondent	This Report is:	Date of Report	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2001	Dec 31, 2001

NOTES TO FINANCIAL STATEMENTS (Continued)

10% annual discount for estimated timing of cash flows	174,000	601,200	131,400
Discounted future net cash flows relating to proved natural gas and oil reserves	$ 262,000	$ 921,300	$ 229,100

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2001	2000	1999
		(In thousands)	
Beginning of year	$ 921,300	$ 229,100	$ 125,100
Net revenues from production	(153,500)	(94,300)	(49,900)
Change in net realization	(1,119,700)	861,700	123,100
Extensions, discoveries and improved recovery, net of future production-related costs	64,200	288,700	33,500
Purchases of proved reserves	2,600	93,200	57,700
Sales of reserves in place	---	(1,500)	(14,700)
Changes in estimated future development costs, net of those incurred during the year	(3,300)	3,400	(9,800)
Accretion of discount	126,900	31,200	16,700
Net change in income taxes	436,500	(412,300)	(59,800)
Revisions of previous quantity estimates	(11,700)	(79,200)	7,400
Other	(1,300)	1,300	(200)
Net change	(659,300)	692,200	104,000
End of year	$ 262,000	$ 921,300	$ 229,100

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end natural gas prices and oil prices. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying statutory tax rates (adjusted for permanent differences and tax credits) to estimated net future pretax cash flows.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of natural gas and oil prices over the remaining reserve lives may vary significantly from current prices.

NOTE 18
Subsequent Event
In January 2002, Fidelity Oil Co. (FOC), one of the company's natural gas and oil production subsidiaries, entered into a compromise agreement with the former operator of certain of FOC's oil production properties in southeastern Montana. The compromise agreement resolved litigation involving the interpretation and application of contractual provisions regarding net proceeds interests paid by the former operator to FOC for a number of years prior to 1998. The terms of the compromise agreement are confidential. As a result of the compromise agreement, the natural gas and oil production segment will reflect a nonrecurring gain in its financial results for the first quarter of 2002 of approximately $16.6 million after-tax. As part of the settlement, FOC gave the former operator a full and complete release, and FOC is not asserting any such claim against the former operator for periods after 1997.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2001	Dec 31, 2001

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 19
Investment in Subsidiaries
The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Resources International, Inc. Centennial Energy Holdings, Inc. owns WBI Holdings, Inc., Knife River Corporation and Utility Services, Inc.

As required by the Federal Energy Regulatory Commission for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $501,669,316 and $517,845,533; current and accrued assets would increase by $376,353,971 and $347,911,277; deferred debits would increase by $276,502,929 and $161,152,427; preferred stock would decrease by $100,000 and $100,000; long-term debt would increase by $625,404,164 and $554,322,288; other noncurrent liabilities and current and accrued liabilities would increase by $157,590,276 and $173,105,095; deferred credits would increase by $373,039,122 and $303,207,667 as of December 31, 2001 and 2000, respectively. Furthermore, operating revenues would increase by $1,799,405,574 and $1,478,998,298; and operating expenses, excluding income taxes, would increase by $1,568,444,117 and $1,310,284,540 for the year ended December 31, 2001 and 2000, respectively. In addition, net cash provided by operating activities would increase by $275,732,000; net cash used in investing activities would increase by $225,841,000; net cash provided by financing activities would decrease by $42,558,000; and the net change in cash and cash equivalents would be an increase of $7,333,000 for the year ended December 31, 2001. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2001

Operating Income	
Electric Utility	
Operating Revenues	$168,836,505
Operating Expenses:	
Operation Expenses	92,104,781
Maintenance Expenses	10,902,653
Depreciation Expenses	19,488,187
Taxes Other Than Income Taxes	7,609,510
Income Taxes:	
Federal Taxes on Income	11,870,494
State Taxes on Income	1,992,706
Deferred Income Taxes	(1,553,968)
Total Electric Expenses	142,414,363
Net Electric Operation	$26,422,142
Gas Utility	
Operating Revenues	$255,389,874
Operating Expenses:	
Operation Expenses	234,442,708
Maintenance Expenses	2,910,554
Depreciation Expenses	9,335,885
Taxes Other Than Income Taxes	5,125,566
Income Taxes:	
Federal Taxes on Income	7,221,178
State Taxes on Income	1,264,342
Deferred Income Taxes	(7,918,005)
Total Gas Expenses	252,382,228
Net Gas Operation	$3,007,646
Net Utility Operating Income	$29,429,788
Revenues from Merchandising, Jobbing and Contract Work	$1,134,973
Revenues from Nonutility Operations	101,825
Equity in Earnings of Subsidiary Companies	135,692,353
Interest and Dividend Income	3,241,340
Miscellaneous Nonoperating Income	21,481
Gain on Disposition of Property	2,429
Total Other Income	140,194,401
Loss on Disposition of Property	118
Miscellaneous Income Deductions	2,800,511
Total Other Income Deductions	2,800,629

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2001

Taxes other than Income Taxes	16,895
Income Taxes - Federal	1,691,077
Income Taxes - State	(1,291,217)
Provision for Deferred Income Taxes	(968,217)
Investment Tax Credits	(731,288)
Total Taxes on Other Income and Deductions	(1,282,750)
Net Other Income and Deductions	$138,676,522
Interest On Long-Term Debt	9,948,155
Amortization of Debt Discount and Expense	1,434,400
Other Interest Expense	1,060,314
Allowance for Borrowed Funds used during Construction	(185,066)
Net Interest Charges	12,257,803
Net Income	$155,848,507

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Function	Balance @ 12/31/00	Balance @ 12/31/01	Average 2001
Distribution	$53,903,158	$55,087,106	$54,495,132
General	6,736,720	6,927,057	6,831,889
Intangible Plant - General	195,788	207,216	201,502
Common	5,584,307	5,178,293	5,381,300
Intangible Plant - Common	1,724,072	1,813,895	1,768,983
Gas Plant Leased to Others	11,374	11,374	11,374
Acquisition Adjustment	97,266	97,266	97,266
Construction Work in Progress (CWIP) In Service not yet Classified	168,681	165,033	166,857
Total Plant in Service	$68,421,366	$69,487,240	$68,954,303

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Acct. No.	Account	Balance @ 12/31/00	Balance @ 12/31/01	Average Balance
	Distribution Plant			
374.1	Land	$41,687	$41,687	$41,687
374.2	Rights of Way	42,598	44,836	43,717
375	Structures & Improvements	180,117	180,117	180,117
376	Mains	26,814,073	27,079,883	26,946,978
378	Meas. & Reg. Equip.-General	514,232	520,093	517,163
379	Meas. & Reg. Equip.-City Gate	174,002	174,002	174,002
380	Services	11,844,722	12,124,678	11,984,700
381	Positive Meters	11,417,140	11,983,141	11,700,140
383	Service Regulators	1,635,648	1,677,415	1,656,532
385	Ind. Meas. & Reg. Station Eqpt.	369,866	371,028	370,447
386.1	Misc. Property on Cust. Premise	1,680	1,680	1,680
386.2	Other Property on Cust. Premise	113,207	113,207	113,207
387.1	Cathodic Protection Equip.	422,588	443,741	433,164
387.2	Other Distribution Equip.	331,598	331,598	331,598
	Total Distribution Plant	$53,903,158	$55,087,106	$54,495,132
	General Plant			
389	Land	$154,460	$154,460	$154,460
390	Structures and Improvements	875,241	892,385	883,813
391.1	Furniture and Fixtures	220,644	216,111	218,378
391.3	Computer Equip. - PC	301,619	308,212	304,915
392.1	Trans. Equip., Non-Unitized	34,635	41,617	38,126
392.2	Trans. Equip., Unitized	1,988,947	2,052,922	2,020,935
393	Stores Equipment	74,396	74,396	74,396
394.1	Tools,Shop&Gar. Eq.-Non-Un.	1,053,692	1,084,749	1,069,220
394.2	Tools,Shop&Gar. Eq.-Unitized	123,956	123,956	123,956
394.3	Vehicle Maintenance Equip.	6,615	6,615	6,615
394.4	Vehicle Refueling Equip.	97,808	97,809	97,809
395	Laboratory Equipment	110,077	119,514	114,795
396.1	Power Operated Equip.	114,117	114,117	114,117
396.2	Work Equipment Trailers	1,268,061	1,317,959	1,293,010
397.1	Radio Comm. Equip.-Fixed	113,542	122,012	117,777
397.2	Radio Comm. Equip.-Mobile	98,837	98,837	98,837
397.3	General Tele. Comm. Equip.	28,055	28,055	28,055
397.5	Supervisory & Tele. Equip.	1,848	1,844	1,846
397.8	Network Equipment	10,599	11,308	10,954
398	Miscellaneous Equipment	59,571	60,179	59,875
	Total General Plant	$6,736,720	$6,927,057	$6,831,889
303	Intangible Plant - General	$195,788	$207,216	$201,502

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Acct. No.	Account	Balance @ 12/31/00	Balance @ 12/31/01	Average Balance
	Common Plant			
389	Land	$222,146	$208,685	$215,415
390	Structures and Improvements	2,748,356	2,404,468	2,576,412
391.1	Furniture and Fixtures	506,882	449,917	478,400
391.2	Computer Equip.- Bull/AS400	11,141	11,535	11,338
391.3	Computer Equip. - PC	577,050	509,396	543,223
391.5	Computer Equip. - Other	97,897	101,183	99,540
392.1	Trans. Equip., Non-Unitized	34,284	36,269	35,277
392.2	Trans. Equip., Unitized	567,625	598,300	582,962
392.3	Aircraft	122,196	126,521	124,359
393	Stores Equipment	4,330	5,168	4,749
394.1	Tools, Shop & Gar. Equip.	33,905	38,118	36,011
394.3	Vehicle Maint. Equip.	14,508	15,170	14,839
394.4	Vehicle Refueling Equip.	103,617	111,753	107,685
396.2	Work Equipment Trailers	18,819	21,680	20,250
397.1	Radio Comm. Equip.-Fixed	87,804	89,113	88,458
397.2	Radio Comm. Equip.-Mobile	158,078	163,356	160,717
397.3	General Tele. Comm. Equip.	93,699	98,802	96,251
397.5	Supervisory & Tele. Equip.	570	10,166	5,368
397.8	Network Equipment	102,956	99,548	101,252
398	Miscellaneous Equipment	78,444	79,145	78,794
	Total Common Plant	$5,584,307	$5,178,293	$5,381,300
303	Intangible Plant - Common	1,724,072	$1,813,895	1,768,983
386.3	Gas Plant Leased to Others	11,374	11,374	11,374
114.2	Acquisition Adjustment	97,266	$97,266	97,266
	Total Gas Plant in Service	$68,252,685	$69,322,207	$68,787,446

MONTANA-DAKOTA UTILITIES CO.
DETAILED COST OF PLANT
GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Acct. No.	Account	Balance @ 12/31/00	Additions	Retirements	Transfers	Balance @ 12/31/01
	Intangible Plant					
303	Misc. Intangible Plant	$477,530	$0	$0	$0	$477,530
	Total Intangible Plant	$477,530	$0	$0	$0	$477,530
	Distribution Plant					
374.1	Land	$99,440	$9,610	($130)	$0	$108,920
374.2	Rights of Way	80,548	9,093	0	0	89,641
375	Structures & Improvements	521,997	0	(786)	0	521,211
376	Mains	76,644,363	1,862,300	(171,125)	(1,385)	78,334,153
378	Measuring & Regulating Equip. - Gen.	1,358,927	17,103	(8,698)	0	1,367,332
379	Measuring & Regulating Equip. - City Gate	1,009,137	0	0	0	1,009,137
380	Services	31,327,485	1,271,678	(123,831)	1,385	32,476,717
381	Meters	28,868,196	2,011,299	(417,487)	0	30,462,008
383	Service Regulators	4,168,755	150,253	(22,146)	0	4,296,862
385	Industrial Measuring & Regulating Equip.	577,038	1,537	(375)	0	578,200
386.1	Misc. Property on Customers' Premise	1,680	0	0	0	1,680
386.2	Other Property on Customer Premise	486,910	0	0	(54,098)	432,812
387.1	Cathodic Protection Equipment	1,391,236	80,332	(20,912)	0	1,450,656
387.2	Other Distribution Equipment	557,183	0	0	0	557,183
	Total Distribution Plant	$147,092,895	$5,413,205	($765,490)	($54,098)	$151,686,512
	General Plant					
389	Land	$300,834	$314			$301,148
390	Structures & Improvements	1,905,840	47,036	0	(29,893)	1,922,983
391.1	Office Furniture & Equipment	601,966	1,106	(29,280)	(29,518)	544,274
391.3	Computer Equip.-PC	802,063	37,416	(42,009)	(16,475)	780,995
392.1	Transportation Equipment - Non-Un.	147,248	13,998	(14,060)	0	147,186
392.2	Transportation Equipment - Unitized	5,708,750	821,038	(481,092)	31,866	6,080,562
393	Stores Equipment	165,410	21,319	0	0	186,729
394.1	Tools,Shop&Gar. Equip.-Non-Un.	2,380,452	130,372	(15,402)	0	2,495,422

CASE NO. _____
STATEMENT C
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MONTANA-DAKOTA UTILITIES CO.
DETAILED COST OF PLANT
GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Acct. No.	Account	Balance @ 12/31/00	Additions	Retirements	Transfers	Balance @ 12/31/01
394.2	Tools,Shop&Gar. Equip.-Non-Un.	334,308	0	(18,661)	(15,837)	299,810
394.3	Vehicle Maintenance Equipment	31,177	0	0	0	31,177
394.4	Vehicle Refueling Equipment	361,344	0	0	0	361,344
395	Laboratory Equipment	269,961	9,499	(8,427)	0	271,033
396.1	Work Equipment Trailers	276,754	23,064	(6,275)	0	293,543
396.2	Power Operated Equipment	3,933,472	1,498,358	(1,350,062)	0	4,081,768
397.1	Radio Communication Equip. - Fixed	461,165	20,490	0	0	481,655
397.2	Radio Communication Equip. - Mobile	420,171	0	0	(18,642)	401,529
397.3	General Tele. Comm. Equip.	101,716	0	(4,232)	(6,966)	90,518
397.5	Supervisory & Tele. Equip.	124,167	0	0	0	124,167
397.6	Scada System	30,894	0	0	0	30,894
397.8	Network Equipment	23,119	7,219	0	0	30,338
398	Miscellaneous Equipment	145,664	3,091	(2,744)	(741)	145,270
	Total General Plant	$18,526,475	$2,634,320	($1,972,244)	($86,206)	$19,102,345
	Common Plant - Gas 1/					
	Total Common Plant	$18,300,687	$0	$0	$0	$17,624,824
	Gas Plant Leased to Others					
386.3	CNG Demo/Lease	25,773	0	0	0	25,773
394.4	Vehicle Refueling Equipment	4,188	0	4,188	0	0
	Total Gas Plant Leased to Others	$29,961	$0	$4,188	$0	$25,773
114.3	Acquisition Adjustments	97,266	0	0	0	97,266
	Total Gas Plant in Service	$184,524,814	$8,047,525	($2,737,734)	($140,304)	$189,014,250

1/ Common plant is either directly assigned or allocated to gas and electric plant. Total common plant additions, retirements and transfers for the twelve months ended December 31, 2001 are $3,021,290, $6,749,761, and $2,992 respectively.

MONTANA-DAKOTA UTILITIES CO.
GAS CWIP IN SERVICE
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Work Order Number	Description	State	Total	Distribution	General	Common
114647	Reconstruction Cost - General Office	ND	($8)			($8)
106274	Purchase modular furniture - General Office	ND	(9)			(9)
106690	Replace carpet - Bismarck Service Ctr.	ND	11,961			11,961
78253	Work Mgmt: Field Ops - SW & System	ND	8,499			8,499
123362	Purchase meter prover	ND	18,156		18,156	
	Small items grouped 1/:					
(107)	Distribution	ND	112,300	112,300		
(5)	General	ND	1,927		1,927	
(36)	Common	ND	12,207			12,207
	Total		$165,033	$112,300	$20,083	$32,650

1/ Numbers in brackets indicate the Number of Work orders involved in each item of construction.

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Function	Balance @ 12/31/00	Balance @ 12/31/01	Average 2001
Distribution	$36,821,948	$38,957,775	$37,889,862
General	3,409,969	3,498,224	3,454,096
Intangible Plant - General	184,802	197,933	191,368
Common	2,485,158	2,592,530	2,538,844
Intangible Plant - Common	460,350	643,890	552,120
Gas Plant Leased to Others	2,570	3,633	3,101
Acquisition Adjustment			
Total Accumulated Reserve	$43,364,797	$45,893,985	$44,629,391

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN ACCUMULATED PROVISION FOR
DEPRECIATION AND AMORTIZATION - GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Gas Utility	Beginning Balance 12/31/00	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 12/31/01
Account 111.2 - Intangible	$427,005	$10,456					$437,461
Account 108							
Distribution	93,354,473	6,622,528	$765,356	$22,152	$381,967	($35,566)	98,816,264
General	8,956,670	878,942	1,976,432	1,421,922	26,776	(48,236)	9,206,090
Total Account 108	102,311,143	7,501,470	2,741,788	1,444,074	408,743	(83,802)	$108,022,354
Total Accounts 111.2 & 108	$102,738,148	$7,511,926	$2,741,788	$1,444,074	$408,743	($83,802)	$108,459,815
Common 1/	$6,891,721						$7,627,806

1/ Common Plant is assigned by state on an actual site and use basis when applicable, and the remainder is allocated by state to gas and electric on a plant in service basis. Total common changes for the twelve months ended December 31, 2001 are:

Common Utility	Beginning Balance 12/31/00	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 12/31/01
Account 111.4	$3,764,289	$1,388,001	$107,051	$4,023	$0	$42,562	$5,006,700
Account 108	18,447,969	2,040,075	6,473,272	4,950,158	$20,292	(85,640)	18,858,998
Total Accounts 111.4 and 108	$22,212,258	$3,428,076	$6,580,323	$4,954,181	$20,292	($43,078)	$23,865,698

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF WORKING CAPITAL AND
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Working Capital	Balance @ 12/31/00	Balance @ 12/31/01
Materials and Supplies	$421,395	$381,856
Fuel Stocks	$23,466	18,683
Prepayments	$17,123	21,567
Gas IRP	176,984	123,984
Total Working Capital	$638,968	$546,090
Customer Advances for Construction	$485,978	$267,859

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001

	Amount
December 2000	$421,395
January 2001	401,493
February	400,198
March	412,074
April	447,350
May	456,135
June	494,388
July	468,617
August	485,970
September	467,424
October	448,553
November	418,186
December	381,856

MONTANA-DAKOTA UTILITIES CO.
FUEL STOCKS
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001

	Amount
December 2000	$23,466
January 2001	25,610
February	22,782
March	22,248
April	20,854
May	12,748
June	15,664
July	10,720
August	25,838
September	28,530
October	28,635
November	23,268
December	18,683

MONTANA-DAKOTA UTILITIES CO.
PREPAID INSURANCE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001

	Amount
December 2000	$17,123
January 2001	1,519
February	6,822
March	8,234
April	(6,394)
May	26,073
June	86,654
July	74,795
August	74,893
September	62,684
October	48,041
November	36,295
December	21,567

MONTANA-DAKOTA UTILITIES CO.
GAS INTEGRATED RESOURCE PLAN
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001

	Amount
December 2000	$176,984
January 2001	172,567
February	168,150
March	163,734
April	159,317
May	154,900
June	150,484
July	146,067
August	141,650
September	137,234
October	132,817
November	128,400
December	123,984

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001

	Amount
December 2000	$485,978
January 2001	482,137
February	477,034
March	483,969
April	434,935
May	432,293
June	433,008
July	280,102
August	281,008
September	281,422
October	278,929
November	267,366
December	267,859

MONTANA-DAKOTA UTILITIES CO.
AVERAGE CAPITAL STRUCTURE
2001

	Balance	Subsidiary Portion of Balance	Adjusted Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$133,500,000		$133,500,000	43.859%	9.302%	4.080%
Preferred Stock	16,450,000		16,450,000	5.404%	4.630%	0.250%
Common Equity	997,932,340	$843,497,103	154,435,237	50.737%	13.250%	6.723%
Total	$1,147,882,340	$843,497,103	$304,385,237	100.000%		11.053%

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MONTANA-DAKOTA UTILITIES CO.
AVERAGE CAPITAL STRUCTURE
PROJECTED 2002

Item	Balance	Subsidiary Portion of Balance	Adjusted Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$133,100,000		$133,100,000	43.606%	9.241%	4.030%
Preferred Stock	16,350,000		16,350,000	5.357%	4.626%	0.248%
Common Equity	1,019,994,648	$864,210,451	155,784,197	51.037%	13.000%	6.635%
Total	$1,169,444,648	$864,210,451	$305,234,197	100.000%		10.913%

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MONTANA-DAKOTA UTILITIES CO.
AVERAGE CAPITAL STRUCTURE
PROJECTED 2003

Item	Balance	Subsidiary Portion of Balance	Adjusted Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$132,600,000		$132,600,000	43.039%	9.180%	3.951%
Preferred Stock	16,250,000		16,250,000	5.274%	4.622%	0.244%
Common Equity	904,790,647	$745,544,872	159,245,775	51.687%	13.250%	6.849%
Total	$1,053,640,647	$745,544,872	$308,095,775	100.000%		11.044%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
2001

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
First Mortgage Bonds			
Balance at 12/31/00	$130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		548,429	
	130,850,000	12,291,871	
Balance at 12/31/01	130,850,000	11,743,442	8.975%
Amortization of Gain/Loss		454,705	
	130,850,000	12,198,147	
Average Balance	$130,850,000	$11,743,442	8.975%
Average Amort. of Gain/Loss		501,567	
	$130,850,000	$12,245,009	9.358%
Pollution Control Bonds			
Balance at 12/31/00	$2,800,000	$183,568	6.556%
Balance at 12/31/01	2,500,000	163,900	6.556%
Average Balance	$2,650,000	$173,734	6.556%
Total Average Long Term Debt	$133,500,000	$12,418,743	9.302%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
PROJECTED 2002

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
First Mortgage Bonds			
Balance at 12/31/01	$130,850,000	$11,743,442	8.975%
Amort. of Gain/Loss		454,705	
	$130,850,000	12,198,147	
Balance at 12/31/02	130,850,000	11,743,442	8.975%
Amort. of Gain/Loss		361,666	
	130,850,000	12,105,108	
Average Balance	$130,850,000	$11,743,442	8.975%
Average Amort. of Gain/Loss		408,186	
	$130,850,000	$12,151,628	9.287%
Pollution Control Bonds			
Balance at 12/31/01	$2,500,000	$163,900	6.556%
Balance at 12/31/02	2,000,000	131,120	6.556%
Average Balance	$2,250,000	$147,510	6.556%
Total Average Long Term Debt	$133,100,000	$12,299,138	9.241%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
PROJECTED 2003

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
First Mortgage Bonds			
Balance at 12/31/02	$130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		361,666	
	$130,850,000	12,105,108	
Balance at 12/31/03	$130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		268,627	
	130,850,000	12,012,069	
Average Balance	$130,850,000	$11,743,442	8.975%
Average Amort. of Gain/Loss		315,147	
	$130,850,000	$12,058,589	9.216%
Pollution Control Bonds			
Balance at 12/31/02	$2,000,000	$131,120	6.556%
Balance at 12/31/03	1,500,000	98,340	6.556%
Average Balance	$1,750,000	$114,730	6.556%
Total Average Long Term Debt	$132,600,000	$12,173,319	9.180%

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2001

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
8.25%	04/01/92	04/01/07	8.250%	$30,000,000	$30,000,000	$225,000	0.750%	$3,663,204	12.211%
8.6%	04/01/92	04/01/12	8.600%	35,000,000	34,911,100	306,250	0.877%	5,698,318	16.322%
6.52%	09/30/97	10/01/04	6.520%	15,000,000	15,000,000	90,000	0.600%	827,077	5.514%
6.71%	09/30/97	10/01/09	6.710%	15,000,000	15,000,000	93,750	0.625%	1,417,846	9.452%
5.83%	09/18/98	10/01/08	5.830%	15,000,000	15,000,000	93,750	0.625%	92,336	0.616%
Pollution Control Refunding Revenue Bonds:									
Mercer County 6.65%	06/01/92	06/01/22	6.650%	15,000,000	15,000,000	0	0.000%	938,724	6.258%
Richland County 6.65%	06/01/92	06/01/22	6.650%	3,250,000	3,250,000	0	0.000%	186,323	5.733%
Morton County 6.65%	06/01/92	06/01/22	6.650%	2,600,000	2,600,000	0	0.000%	179,014	6.885%
Pollution Control Notes:									
Grant County 6.2%	03/01/74	03/01/04	6.200%	5,600,000	5,600,000	84,000	1.500%	88,958	1.589%
				$136,450,000	$136,361,100	$892,750		$13,091,800	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
First Mortgage Bonds:						
Secured Medium-term Notes, Series A:						
8.25%	$26,111,796	87.039%	10.177%	$30,000,000	$3,053,100	
8.6%	28,906,532	82.590%	11.020%	35,000,000	3,857,000	
6.52%	14,082,923	93.886%	7.811%	15,000,000	1,171,650	
6.71%	13,488,404	89.923%	8.195%	15,000,000	1,229,250	
5.83%	14,813,914	98.759%	6.086%	15,000,000	912,900	
Pollution Control Refunding Revenue Bonds:						
Mercer County 6.65%	14,061,276	93.742%	7.288%	15,000,000	1,093,200	
Richland County 6.65%	3,063,677	94.267%	7.243%	3,250,000	235,398	
Morton County 6.65%	2,420,986	93.115%	7.344%	2,600,000	190,944	
Total First Mortgage Bonds	116,949,508			130,850,000	11,743,442	8.975%
Pollution Control Notes:						
Grant County 6.2%	5,427,042	96.911%	6.556%	2,500,000	163,900	6.556%
Total Long-Term Debt Capital	$122,376,550			$133,350,000	$11,907,342	8.929%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

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MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
2001

		Projected Average Amortization
Acct. 1890 - Unamortized Loss		
9 1/8% due 05-15-06	1/01 - 12/01	$548,429
9 1/8% due 05-15-06	1/02 - 12/02	454,705
Average at 12/31/01		$501,567

MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
PROJECTED 2002

		Projected Average Amortization
Acct. 1890 - Unamortized Loss		
9 1/8% due 05-15-06	1/02 - 12/02	$454,705
9 1/8% due 05-15-06	1/03 - 12/03	361,666
Average at 12/31/02		$408,186

MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
PROJECTED 2003

		Projected Average Amortization
Acct. 1890 - Unamortized Loss		
9 1/8% due 05-15-06	1/02 - 12/02	$361,666
9 1/8% due 05-15-06	1/03 - 12/03	268,627
Average at 12/31/03		$315,147

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
2001

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance at 12/31/00	$16,500,000	$764,275	4.632%
Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance at 12/31/01	$16,400,000	$758,990	4.628%
Average Preferred Stock	$16,450,000	$761,633	4.630%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
PROJECTED 2002

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance at 12/31/01	$16,400,000	$758,990	4.628%
Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance at 12/31/02	$16,300,000	$753,705	4.624%
Average Preferred Stock	$16,350,000	$756,348	4.626%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
PROJECTED 2003

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance at 12/31/02	$16,300,000	$753,705	4.624%
Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance at 12/31/03	$16,200,000	$748,420	4.620%
Average Preferred Stock	$16,250,000	$751,063	4.622%

MONTANA-DAKOTA UTILITIES CO.
PREFERRED STOCK CAPITAL
DECEMBER 31, 2001

Description	Date of Issuance	Call (Redemption) Price	Dividend Rate	Par Value of Issue	Gross Proceeds (000's)	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Issuance Expense Amount	Issuance Expense % Gross Proceeds
4.5% Series	01/01/51	$105	4.5%	$100	$10,000				
4.7% Series	12/07/55	102	4.7%	100	5,000				
5.1% Series	05/23/61	100/102	5.1%	100	5,000	$25,000	0.50%	$27,452	0.54

Description	Net Proceeds Amount (000's)	Net Proceeds Per Unit	Cost of Money 1/ 2/	Principal Outstanding	December 31, 2001 Annual Cost	December 31, 2001 Embedded Cost	Method of Offering
4.5% Series	$10,000	100.000%	4.500%	$10,000,000	$450,000		Public
4.7% Series	5,000	100.000%	4.700%	5,000,000	235,000		Public
5.1% Series	4,948	98.951%	5.285%	1,400,000	73,990		Private
Total				$16,400,000	$758,990	4.628%	

1/ Yield to maturity based upon the life, net proceeds, and quarterly compounding of the stated dividend rate of each issue.
2/ 4.5% Series and 4.7% Series issue expense fully recovered.

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Schedule F-2
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MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
2001

Description	Amount
Common Equity - 12/31/00	$884,686,278
Unappropriated Retained Earnings of Subsidiaries	257,307,989
Additional Equity of Subsidiaries (Centennial)	473,128,189
Utility Common Equity - 12/31/00	$154,250,100
Common Equity - 12/31/01	$1,111,178,402
Unappropriated Retained Earnings of Subsidiaries	353,291,342
Additional Equity of Subsidiaries (Centennial)	603,266,687
Utility Common Equity - 12/31/01	$154,620,373
Average Common Utility Equity - 12/31/01	$154,435,237

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
PROJECTED 2002

Description	Amount
Common Equity - 12/31/01	$1,111,178,402
Unappropriated Retained Earnings of Subsidiaries	353,291,342
Additional Equity of Subsidiaries (Centennial)	603,266,687
Utility Common Equity - 12/31/01	$154,620,373
Common Equity - 12/31/02	$928,810,893
Unappropriated Retained Earnings of Subsidiaries	168,271,000
Additional Equity of Subsidiaries (Centennial)	603,591,872
Utility Common Equity - 12/31/02	$156,948,021
Average Common Utility Equity - 12/31/02	$155,784,197

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
PROJECTED 2003

Description	Amount
Common Equity - 12/31/02	$928,810,893
Unappropriated Retained Earnings of Subsidiaries	168,271,000
Additional Equity of Subsidiaries (Centennial)	603,591,872
Utility Common Equity - 12/31/02	$156,948,021
Common Equity - 12/31/03	$880,770,400
Unappropriated Retained Earnings of Subsidiaries	115,635,000
Additional Equity of Subsidiaries (Centennial)	603,591,872
Utility Common Equity - 12/31/03	$161,543,528
Average Common Utility Equity - 12/31/03	$159,245,775

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Schedule F-4

MDU RESOURCES GROUP, INC.
STOCK DIVIDENDS, STOCK SPLITS OR CHANGES IN PAR OR STATED VALUE
FOR THE FIVE-YEAR PERIOD ENDING DECEMBER 31, 2001

On June 30, 1998, MDU Resources Group, Inc. issued 17,203,148 additional shares of Common Stock, Par value $3.33, in connection with a three-for-two Common Stock split to be effected in the form of a fifty percent stock dividend.

On April 30, 1999, the MDU Resources Group, Inc. Certificate of Incorporation was amended pursuant to stockholder approval. The amendment to the Certificate of Incorporation increased the number of shares of common stock which the company is authorized to issue from 75,000,000 shares of common stock with a par value of $3.33 to 150,000,000 shares with a par value of $1.00.

MDU RESOURCES GROUP, INC.
COMMON STOCK DATA
FOR THE FIVE YEARS ENDED DECEMBER 31, 2001

	Avg. Number of Shares Outstanding (000's)	Annual Earnings (per share)		Annual Dividends (per share)	Dividend/ Earnings Ratio	Average Market Price 1/	Earnings/ Price Ratio	Dividend/ Price Ratio
Year Ended December 31:								
1997	43,478	1.24		0.75	61%	16.62	7.5%	4.5%
1998	50,837	0.66	2/	0.78	119%	23.82	2.8%	3.3%
1999	54,870	1.52		0.82	54%	22.90	6.6%	3.6%
2000	61,390	1.80		0.86	48%	24.03	7.5%	3.6%
2001	67,869	2.29		0.90	39%	30.25	7.6%	3.0%
Twelve Months:								
January, 2001	62,103	1.96		0.86	44%	30.07	6.5%	2.9%
February	62,802	1.99		0.87	44%	29.14	6.8%	3.0%
March	63,583	2.04		0.87	43%	31.78	6.4%	2.7%
April	64,315	2.15		0.87	40%	37.86	5.7%	2.3%
May	64,877	2.31		0.88	38%	38.12	6.1%	2.3%
June	65,488	2.32		0.88	38%	34.19	6.8%	2.6%
July	66,008	2.37		0.88	37%	30.45	7.8%	2.9%
August	66,489	2.42		0.89	37%	29.90	8.1%	3.0%
September	66,824	2.43		0.89	37%	25.54	9.5%	3.5%
October	67,199	2.40		0.89	37%	24.88	9.6%	3.6%
November	67,529	2.38		0.90	38%	24.83	9.6%	3.6%
December	67,869	2.29		0.90	39%	26.25	8.7%	3.4%

1/ This average market price is based on monthly high and low for the year.
2/ Reflects $39.9 million or 78 cents per common share in noncash after-tax write-down of natural gas and oil properties.

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Case No. ___
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MONTANA-DAKOTA UTILITIES CO.
REACQUISITION OF BONDS OR PREFERRED STOCK
FOR THE FIVE-YEAR PERIOD ENDING DECEMBER 31, 2001

First Mortgage Bonds

There was no reacquisition of bonds during the five years ending December 31, 2001.

Preferred Stock

Title	Principal Amount	Reacquisition Cost	Gain or (Loss)
Preferred Stock:			
5.1% Preferred Stock	$500,000	$500,000	$0

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001

	Dk	Revenue
Sales		
Residential	7,536,083	$55,953,876
Firm General	5,368,130	36,971,326
Air Force		
Firm	438,620	2,885,915
Interuptible	574,653	2,376,658
Total Air Force	1,013,273	5,262,573
Small Interruptible	396,829	2,073,804
Large Interruptible	1,927	12,839
Total Sales	14,316,242	$100,274,418
Transportation		
Small Interruptible	995,200	$619,071
Large Interruptible	2,958,456	566,568
Total Transportation	3,953,656	$1,185,639
Unbilled Revenue		(6,333,647)
Total Throughput	18,269,898	$95,126,410
Other Revenue		
Miscellaneous Service Revenue		$77,411
Rent from Property		198,260
Other Revenue		11,695
Total Other Revenue		$287,366

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Per Books		Per Books @ Current Rates 1/		Normalized @ Current Rates 1/	
Rate Reporting Class	Dk	Revenue	Dk	Revenue	Dk	Revenues
Sales						
Residential						
Residential	7,518,765	$55,772,710	7,518,765	$37,499,896	7,664,225	$38,115,862
Seasonal	134	977	134	643	134	643
Propane	17,184	180,189	17,184	93,167	17,635	95,150
Total Residential	7,536,083	55,953,876	7,536,083	37,593,706	7,681,994	38,211,655
Air Force						
Firm	438,620	2,885,915	438,620	1,127,819	38,538	140,197
Interruptible	574,653	2,376,658	574,653	1,382,841	979,467	2,363,050
Total Air Force	1,013,273	5,262,573	1,013,273	2,510,660	1,018,005	2,503,247
Firm General						
Firm General	5,326,001	36,644,409	5,326,001	23,600,063	5,428,533	24,155,673
Seasonal	12,558	52,617	12,558	42,838	12,558	42,838
Propane	29,571	274,300	29,571	131,986	29,901	131,425
Total Firm General	5,368,130	36,971,326	5,368,130	23,774,887	5,470,992	24,329,936
Interruptible						
Small Interruptible	396,829	2,073,804	396,829	1,144,153	489,700	1,403,132
Large Interruptible	1,927	12,839	1,927	5,940	0	0
Total Interruptible	398,756	2,086,643	398,756	1,150,093	489,700	1,403,132
Total Sales	14,316,242	100,274,418	14,316,242	65,029,346	14,660,691	66,447,970
Transportation						
Small Interruptible	995,200	619,071	995,200	619,071	1,030,440	557,408
Large Interruptible	2,958,456	566,568	2,958,456	566,568	2,246,820	342,735
Total Transportation	3,953,656	1,185,639	3,953,656	1,185,639	3,277,260	900,143
Total Sales & Transportation	18,269,898	$101,460,057	18,269,898	$66,214,985	17,937,951	$67,348,113

1/ Gas rates effective with service rendered on and after January 15, 1999, PGA effective with bills rendered on and after March 1, 2002, exclusive of surcharge.

CASE NO. _____
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PAGE 2 OF 3

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002 AND 2003

Rate Reporting Class	Projected 2002 @ Current Rates 1/ Dk	Projected 2002 @ Current Rates 1/ Revenues	Projected 2003 @ Current Rates 1/ Dk	Projected 2003 @ Current Rates 1/ Revenues
Sales				
Residential				
Residential	7,876,860	$39,020,222	7,881,870	$39,101,817
Seasonal	0	0	0	0
Propane	17,980	96,455	17,970	96,566
Total Residential	7,894,840	39,116,677	7,899,840	39,198,383
Air Force				
Firm	36,450	132,624	36,450	132,624
Interruptible	1,014,790	2,448,094	1,014,790	2,448,094
Total Air Force	1,051,240	2,580,718	1,051,240	2,580,718
Firm General				
Firm General	5,582,860	24,660,321	5,565,190	24,596,733
Seasonal	13,170	44,850	13,130	44,725
Propane	30,990	138,181	30,900	137,868
Total Firm General	5,627,020	24,843,352	5,609,220	24,779,326
Interruptible				
Small Interruptible	489,700	1,403,132	489,700	1,403,132
Large Interruptible	0	0	0	0
Total Interruptible	489,700	1,403,132	489,700	1,403,132
Total Sales	15,062,800	67,943,879	15,050,000	67,961,559
Transportation				
Small Interruptible	1,030,440	557,408	1,030,440	557,408
Large Interruptible	2,246,820	342,735	2,246,820	342,735
Total Transportation	3,277,260	900,143	3,277,260	900,143
Total Sales & Transportation	18,340,060	$68,844,022	18,327,260	$68,861,702

1/ Gas rates effective with service rendered on and after January 15, 1999, PGA effective with bills rendered on and after March 1, 2002, exclusive of surcharge.

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STATEMENT G
PAGE 3 OF 3

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Company	North Dakota
Cost of Gas	$175,758,472	$76,842,325
Other Gas Supply	456,216	215,821
Distribution	12,891,567	5,161,948
Customer Accounts	7,356,046	2,834,946
Customer Service & Infor.	320,139	165,360
Sales	1,319,137	470,362
Administrative and General	9,778,684	4,090,058
Total Operation and Maintenance Expenses	$207,880,261	$89,780,820

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Account No.		Total Company	North Dakota
	Other Gas Supply Expenses		
804	Natural Gas City Gate Purchases	$175,866,964	$75,138,425
805.1	Purchased Gas Cost Adjustments	21,181,975	10,328,560
808.1	Gas Withdrawn from Storage	31,427,333	13,940,149
808.2	Gas Delivered to Storage	(52,717,800)	(22,564,809)
812	Gas Used for Other Utility Operations - Cr.		
813	Other Gas Supply Expenses	456,216	215,821
	Total Other Gas Supply Expenses	$176,214,688	77,058,146
	Distribution Expenses		
	Operation		
870	Supervision and Engineering	$1,411,147	$516,161
871	Distribution Load Dispatching	176,130	70,675
874	Mains and Services	2,471,633	878,937
875	Measuring & Reg. Station Exp. - General	84,913	35,628
876	Measuring & Reg. Station Exp. - Industrial	68,738	37,388
877	Measuring & Reg. Station Exp. - City Gate	42,161	7,257
878	Meters and House Regulators	1,414,119	585,682
879	Customer Installations	2,157,427	760,312
880	Other Expenses	3,061,421	1,421,151
881	Rents	98,127	20,705
	Total Operation Expenses	10,985,816	4,333,896
	Maintenance		
885	Supervision & Engineering	585,381	272,457
886	Structures & Improvements	4,837	2,317
887	Mains	290,922	118,089
889	Measuring & Reg. Station Exp. - General	50,294	25,142
890	Measuring & Reg. Station Exp. - Industrial	10,412	4,594
891	Measuring & Reg. Station Exp. - City Gate	2,534	410
892	Services	278,635	116,078
893	Meters and House Regulators	231,934	103,235
894	Other Equipment	450,802	185,730
	Total Maintenance Expenses	1,905,751	828,052
	Total Distribution Expenses	$12,891,567	$5,161,948
	Customer Accounts Expenses		
	Operation		
901	Supervision	$518,844	$229,995
902	Meter Reading Expenses	1,479,250	583,212
903	Customer Records and Collection Exp.	3,831,637	1,519,399
904	Uncollectible Accounts	1,070,003	343,493
905	Misc. Customer Accounts Expenses	456,312	158,847
	Total Customer Accounts Expenses	$7,356,046	$2,834,946

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Account No.		Total Company	North Dakota
	Customer Service & Information Expenses		
	Operation		
907	Supervision	$33,969	$19,512
908	Customer Assistance Expenses	181,109	92,576
909	Informational and Instructional Expenses	100,475	49,245
910	Misc. Customer Service & Info. Exp.	4,586	4,027
	Total Customer Service & Info. Exp.	$320,139	$165,360
	Sales Expenses		
	Operation		
911	Supervision	$316,876	$131,219
912	Demonstrating and Selling Expenses	778,044	254,981
913	Advertising Expenses	138,927	54,351
916	Misc. Sales Expenses	85,290	29,811
	Total Sales Expenses	$1,319,137	$470,362
	Administrative & General Expenses		
	Operation		
920	Administrative and General Salaries	$3,013,271	1,205,794
921	Office Supplies and Expenses	1,679,940	666,085
923	Outside Services Employed	387,097	132,860
924	Property Insurance	127,084	50,855
925	Injuries and Damages	607,310	238,182
926	Employee Pensions and Benefits	2,481,944	1,055,980
927	Franchise Requirements	49	49
928	Regulatory Commission Expenses	32,984	1,050
930.1	General Advertising Expenses	128,744	80,898
930.2	Miscellaneous General Expenses	516,484	234,845
931	Rents	219,827	170,993
	Total Operation Expenses	9,194,734	3,837,591
	Maintenance		
935	Maintenance of General Plant	583,950	252,467
	Total Administrative & General Expenses	$9,778,684	$4,090,058
	Total Operation & Maintenance Expenses	$207,880,261	$89,780,820

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION EXPENSE AND AMORTIZATION
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Company	North Dakota
Distribution	$6,620,119	$2,522,481
General	335,764	127,855
Common	555,346	220,058
Amortization of Intangible Plant - General	10,456	2,511
Amortization of Intangible Plant - Common	501,814	185,393
Gas Plant Leased to Others	2,703	1,064
Amortization of Acquisition Adjustment		
Total Depreciation and Amort. Expense	$8,026,202	$3,059,362

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION AND AMORTIZATION EXPENSES
GAS UTILITY – NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001

See Pages 3 through 5 for Montana-Dakota's depreciation rates as set forth in a study performed by Stone and Webster Management Consultants, Inc. as of December 31, 1992 for gas and common plant. See page 6 for internally developed rates as of December 31, 2001 for computer equipment and network equipment.

MONTANA DAKOTA UTILITY COMPANY
GAS PLANT
SUMMARY OF ANNUAL DEPRECIATION AMOUNTS AND RATES
UTILITY PLANT IN SERVICE AT DECEMBER 31,1991

CASE NO. _____
STATEMENT I
PAGE 3 OF 6

ACCOUNT NUMBER AND DESCRIPTION	PLANT BALANCE	EST. SALVAGE OR RETIREMENT COST PCT	AMOUNT	ESTIMATED SERVICE VALUE	MORT. DISPERS YRS	CRV	BOOK DEPR. RESERVE	UNRECOVERD SERVICE VALUE	EST. REM. LIFE	ANNUAL DEPRECIATION AMOUNT	PCT.
	DISTRIBUTION PLANT										
374.2	LAND RIGHTS	72132			72132	FORECAST	34762	37370	20.1	1859	2.58
375	STRUCTURES AND IMPROVEMENTS	364728	-10	-36473	401201	39 R2	203226	197975	22.6	8760	2.40
376	DISTRIBUTION MAINS	51885311	-40	-20754124	72639435	36 R5	29073442	43565993	20.1	2167462	4.18
378	MEASURING AND REGULATING EQUIPMENT - GENERAL	1076163			1076163	33 R2.5	613745	462418	18.7	24728	2.30
379	MEASURING AND REGULATING EQUIP-CITY GATE	323078			323078	30 R0.5	160214	162864	18.4	8851	2.74
380	SERVICES	20072746	-140	-28101844	48174590	34 R3	12210080	35964510	21.8	1649748	8.22
381	METERS	19054646	10	1905465	17149181	33 R1.5	6598738	10550443	21.5	490718	2.58
383	HOUSE REGULATORS	2933282	10	293328	2639954	34 R1.5	1048699	1591255	22.9	69487	2.37
385	INDUSTRIAL MEASURING AND REGULATING EQUIPMENT	444153	20	88831	355322	35 R2.5	153853	201469	23.7	8501	1.91
387	OTHER EQUIPMENT	1200559			1200559	20 R2	356058	844501	13.5	62556	5.21
	TOTAL	97426798		-46604817	144031615		50452817	93578798		4492670	4.61
	GENERAL PLANT										
390	STRUCTURES AND IMPROVEMENTS	1781026	-5	-89051	1870077	36 R1.5	853464	1016613	24.4	41664	2.34
391	OFFICE FURNITURE AND EQUIPMENT	492877	5	24644	468233	17 S1	216720	251513	12.6	19961	4.05
393	STORES EQUIPMENT	134157			134157	39 R4	108291	25866	21.5	1203	0.90
394.1	TOOLS, SHOP & GARAGE EQUIPMENT	1566403	10	156640	1409763	20 R0.5	655173	754590	13.5	55896	3.57
394.3	VEHICLE MAINTENANCE EQUIPMENT	17674			17674	25 S3	643	17031	22.9	744	4.21
394.4	VEHICLE REFUELING EQUIPMENT	324491			324491	15 R2.5	-12195	336686	11.1	30332	9.35
395	LABORATORY EQUIPMENT	194819			194819	35 S2	65040	129779	28.7	4522	2.32
397.1	RADIO COMMUNICATION EQUIPMENT -FIXED	314490			314490	24 R2	140147	174343	15.1	11546	3.67
397.3	GENERAL TELEPHONE COMMUNICATIONS EQUIPMENT	56555	5	2828	53727	15 R2.5	8864	44863	12.1	3708	6.56
397.5	SUPERVISORY AND TELEMETERING EQUIPMENT	112400			112400	12 L5	41976	70424	9.4	7492	6.67
397.6	COMMUNICATION EQUIPMENT - SCADA	29510			29510	14 SQ	9505	20005	4.5	4446	15.07
398	MISCELLANEOUS EQUIPMENT	93493	15	14024	79469	35 S6	68563	10906	19.9	548	0.59
	TOTAL	5117895		109085	5008810		2156191	2852619		182062	3.56
	TOTAL DEPRECIABLE PLANT	102544693		-46495732	149040425		52609008	96431417		4674732	4.56

MONTANA DAKOTA UTILITY COMPANY
COMMON PLANT
SUMMARY OF ANNUAL DEPRECIATION AMOUNTS AND RATES
UTILITY PLANT IN SERVICE AT DECEMBER 31,1991

CASE NO. _____
STATEMENT I
PAGE 4 OF 6

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE	EST. RETIREMENT PCT	SALVAGE OR COST AMOUNT	ESTIMATED SERVICE VALUE	MORT. DISPERS YRS	MORT. DISPERS CRV	BOOK DEPR. RESERVE	UNRECOVERD SERVICE VALUE	EST. REM. LIFE	ANNUAL DEPRECIATION AMOUNT	ANNUAL DEPRECIATION PCT.
	GENERAL PLANT											
390	STRUCTURES AND IMPROVEMENTS	15187083	-10	-1518708	16705791	35	S5	3789606	12916185	22.6	571513	3.76
391	OFFICE FURNITURE AND EQUIPMENT	3575250	15	536287	3038963	28	R0.5	1969838	1069125	20.2	52927	1.48
394.3	TOOLS, SHOP & GARAGE EQUIPMENT	33440			33440	25	S3	3721	29719	19.9	1493	4.46
394.4	TOOLS, SHOP & GARAGE EQUIPMENT	448613			448613	15	R2.5	48324	400289	10.6	37763	8.42
397.1	FIXED RADIOS	573054			573054	24	R2	218472	354582	14.3	24796	4.33
397.2	MOBILE RADIOS	1203656			1203656	16	R3	617116	586540	7.3	80348	6.68
397.3	TELEPHONE COMMUNICATION EQUIPT	263485	5	13174	250311	15	R2.5	51588	198723	7.1	27989	10.62
397.5	SUPERVISORY AND TELEMETERING EQUIPMENT	10015			10015	12	L5	9521	494	8.4	59	0.59
398	MISCELLANEOUS EQUIPMENT	364023	5	18201	345822	18	R2	253703	92119	10.1	9121	2.51
	TOTAL	21658619		-951046	22609665			6961889	15647776		806009	3.72
	TOTAL DEPRECIABLE PLANT	21658619		-951046	22609665			6961889	15647776		806009	3.72
	OTHER PROPERTY											
389	LAND	1432010						0				
391.1	COMPUTER EQUIPMENT	5234972						3042402				
392	TRANSPORTATION EQUIPMENT	9189325						6019667				
303	FRANCHISES AND CONSENTS	101280						0				
	TOTAL	15957587						9062069				
	TOTAL UTILITY PLANT	37616206						16023958				

MONTANA-DAKOTA UTILITIES CO.
ANNUAL DEPRECIATION RATES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Account Number		Depreciation Rate
	General Plant	
391.3	Computer Equip. - PC	12.50%
	Common	
391.2	Computer Equip.- Bull/AS400	14.17%
391.3	Computer Equip. - PC	12.50%
391.5	Computer Equip. - Other	26.51%
397.8	Network Equipment	12.50%

MONTANA-DAKOTA UTILITIES CO.
RECONCILIATION OF DEPRECIABLE GAS PLANT
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Balance @ 12/31/00	Balance @ 12/31/01	Average Balance
Depreciable Plant			
Distribution	$53,861,471	$55,045,419	$54,453,445
General	3,052,544	3,122,026	3,087,285
General - Amortized	195,788	207,216	201,502
Gas Plant Leased to Others	11,374	11,374	11,374
	$57,121,177	$58,386,035	$57,753,606
Depreciable Plant Charged to a Clearing Account			
Transportation Equipment	$2,023,582	$2,094,539	$2,059,061
Tools, Shop & Garage Equipment - Unitized	123,956	123,956	123,956
Power Operated Equipment	114,117	114,117	114,117
Work Equipment	1,268,061	1,317,959	1,293,010
	$3,529,716	$3,650,571	$3,590,144
Non-Depreciable Plant			
Distribution	$41,687	$41,687	$41,687
General	154,460	154,460	154,460
	$196,147	$196,147	$196,147
Common Plant in Service - Gas			
Depreciable	$4,619,237	$4,186,838	$4,403,038
Charged to Clearing Account	742,924	782,770	762,847
Depreciable - Amortized	1,724,072	1,813,895	1,768,983
Non-Depreciable	222,146	208,685	215,415
	$7,308,379	$6,992,188	$7,150,283
Acquisition Adjustment - Amortized	$97,266	$97,266	$97,266
Total Gas Plant in Service	$68,252,685	$69,322,207	$68,787,446

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Type of Tax	Total Company	North Dakota
Ad Valorem	$2,664,923	$603,829
O&M Related Taxes		
Payroll		
FICA	$1,400,418	$579,783
Federal & State Unemployment	19,386	8,027
Total Payroll	$1,419,804	$587,810
Delaware Franchise	50,649	20,573
Total O&M Related Taxes	$1,470,453	$608,383
Other		
Hettinger Franchise	$12,877	$12,877
Wyoming Franchise	87,047	
Montana Consumer Counsel	54,724	
Montana PSC	186,033	
South Dakota Special Hearing Fund	62,534	
Wyoming Revolving Fund	30,830	
Secretary of State	511	208
Highway Use Tax	440	161
Total Other	$434,996	$13,246
Total Taxes Other Than Income	$4,570,372	$1,225,458

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Type of Tax	Total Company
Ad Valorem	
Montana	
Distribution	$1,362,901
General	78,746
Common	92,821
Total Montana	$1,534,468
North Dakota	
Distribution	$489,087
General	51,828
Common	60,018
Intangible - General	2,896
Total North Dakota	$603,829
South Dakota	
Distribution	$404,961
General	46,500
Common	27,848
Intangible - General	1,045
Total South Dakota	$480,354
Wyoming	
Distribution	$32,701
General	1,450
Common	11,932
Intangible - General	189
Total Wyoming	$46,272
Total Ad Valorem Taxes	$2,664,923

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Company	North Dakota
Operating Revenue	$223,964,781	$95,413,776
Operating Expense:		
O&M Expense	207,880,261	89,780,820
Depreciation Expense	8,026,202	3,059,362
Taxes Other than Income	4,570,372	1,225,458
Total Operating Expense	220,476,835	94,065,640
Operating Income	3,487,946	1,348,136
Interest Expense	2,956,718	1,013,654
Book Taxable Income before Adjustments	531,228	334,482
Deductions and Adjustments to Book Income:		
Tax Deductions 1/	(22,741,957)	(10,671,187)
Preferred Dividend Paid Deduction	36,612	13,572
Total Deductions and Adjustments	(22,705,345)	(10,657,615)
Taxable Income - Before State Income Tax	23,236,573	10,992,097
Less: State Income Taxes	1,344,508	861,216
Federal Taxable Income	21,892,065	10,130,881
Federal Income Taxes @ 35%	7,662,223	3,545,808
Credits and Adjustments	(303,914)	(54,273)
State Income Taxes	1,344,508	861,216
Federal and State Income Taxes	8,702,817	4,352,751
Rounding and Prior Year's Adjustment	(51,776)	(30,408)
Total Federal and State Income Taxes	$8,651,041	$4,322,343

1/ See page 6.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
TAX DEDUCTIONS
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Company	North Dakota
1900 Account M-1's		
Management Incentive Compensation	($166,547)	($67,648)
Pension Expense	1,841,132	747,828
Sundry Reserves	16,686	5,536
Reserve for Deferred Maintenance	15,732	5,813
Property Insurance Adjustment	(57,285)	(21,165)
Bad Debt Expense	219,878	33,706
Accrued Vacation	136,541	55,460
Capitalized Overheads	(925,251)	(375,817)
Customer Advances	42,191	67,468
Restricted Stock Bonus Plan	138,597	56,295
FAS 106 - OPRB	81,602	33,145
Deferred Compensation	(42,491)	(17,259)
BOD Retirement	(649,334)	(263,746)
Demand Charges	(8,194)	17,742
PCB related income	(19,586)	(4,985)
Plant reclassification		(7,677)
2820 Account M-1's		
Liberalized Depreciation and Other Property Timing Differences	(1,714,071)	(552,874)
Contributions in Aid of Construction	(46,714)	(42,068)
2830 Account M-1's		
Purchased Gas Cost Adjustment	(21,010,649)	(10,095,293)
Amortization of Loss on Bond Retirements	(322,077)	(106,850)
FAS 106 - Deferred Expense	(110,861)	(56,330)
Gas IRP	(88,708)	(53,000)
Permanent M-1's		
Meals & Entertainment	(63,048)	(25,609)
Federal Nonhwy Use Tax Credit	(9,500)	(3,859)
Total M-1 Deductions	($22,741,957)	($10,671,187)

MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAXES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Utility	North Dakota
Gas Utility - Rate Base Deductions:		
Depreciation, Retirements and Other Timing Differences Required to be Normalized	($118,682)	($93,150)
Contributions In Aid of Construction	(28,145)	(25,346)
Customer Advances	16,603	26,724
Total Rate Base Deductions	(130,224)	(91,772)
Gas Utility - Current Timing Differences:		
Management Incentive Compensation	(63,589)	(26,796)
Pension Expense	702,960	296,215
Sundry Reserves	6,317	2,192
Reserve For Deferred Maintenance	5,799	2,235
Property Insurance Adjustment	(21,779)	(8,384)
Bad Debt Expense	83,552	13,351
Accrued Vacation	52,133	21,968
Capitalized Overheads	(353,269)	(148,861)
Restricted Stock Bonus Plan	52,917	22,298
FAS 106	(11,438)	(8,809)
Deferred Compensation	(16,224)	(6,837)
BOD Retirement	(247,922)	(104,470)
Demand Charges	(5,994)	7,028
PCB Related Income	(7,251)	(3,081)
Unrecovered Purchased Gas Cost	(8,045,938)	(3,998,747)
Demand Charges		
Rate Case Expense		
Amort of Loss on Bond Retirements	(121,934)	(42,324)
Gas IRP	(35,062)	(20,993)
Closing/Filing and Out of Period	324,641	64,093
Total Current Timing Differences	(7,702,081)	(3,939,922)
Total Deferred Income Taxes	($7,832,305)	($4,031,694)

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF ACCUMULATED DEFERRED INCOME TAXES
GAS UTILITY - NORTH DAKTOA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Company		North Dakota		
	Balance 12/31/00	Balance 12/31/01	Balance 12/31/00	Balance 12/31/01	Average Balance
Gas Utility - Rate Base Deductions:					
Depreciation, Retirements and Other Timing Differences Required to be Normalized	$10,378,059	$10,412,307	$3,873,914	$3,879,373	3,876,644
Contributions In Aid of Construction	(143,527)	(175,753)	(65,535)	(90,987)	(78,261)
North Dakota Full Normalization	636,111	577,102	636,111	577,102	606,606
Customer Advances for Construction	(222,618)	(207,018)	(123,149)	(93,496)	(108,323)
Other	37,289	45,158			0
Montana Rate Case Adjustments	196,955	249,806			0
Total	$10,882,269	$10,901,602	$4,321,341	$4,271,992	$4,296,666

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MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF UNAMORTIZED INVESTMENT TAX CREDITS
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Company	North Dakota
Balance @		
December 31, 2000	$669,642	$306,663
December 31, 2001	$601,555	$273,541
Average Balance	$635,599	$290,102

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Company	North Dakota	Other	Reference
Operating Revenues				
Sales	$220,239,676	$93,961,471	$126,278,205	Statement G
Transportation	3,049,204	1,164,938	1,884,266	Statement G
Other	675,901	287,366	388,535	Statement G
Total Revenues	223,964,781	95,413,775	128,551,006	
Operating Expenses				
Operation and Maintenance				
Cost of Gas	175,758,472	76,842,325	98,916,147	Statement H
Other O&M	32,121,789	12,938,495	19,183,294	Statement H
Total O&M	207,880,261	89,780,820	118,099,441	
Depreciation	8,026,202	3,059,362	4,966,840	Statement I
Taxes Other Than Income	4,570,372	1,225,457	3,344,915	Statement J
Current Income Taxes	8,651,041	4,322,343	4,328,698	Statement K
Deferred Income Taxes	(7,832,305)	(4,031,694)	(3,800,611)	Statement K
Total Expenses	221,295,571	94,356,288	126,939,283	
Operating Income	$2,669,210	$1,057,487	$1,611,723	

MONTANA-DAKOTA UTILITIES CO.
RATE BASE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2001

	Total Company	North Dakota	Other	Reference
Gas Plant in Service	$188,979,508	$69,322,207	$119,657,301	Statement C
Accumulated Reserve for Depreciation	116,082,619	45,893,985	70,188,634	Statement D
Net Gas Plant in Service	72,896,889	23,428,222	49,468,667	
CWIP in Service Pending Reclassification	1,431,820	165,033	1,266,787	Statement C
Total Gas Plant in Service	74,328,709	23,593,255	50,735,454	
Additions				
Materials and Supplies	1,031,637	381,856	649,781	Statement E
Fuel Stocks	18,683	18,683	0	Statement E
Gas in Underground Storage	8,690,912	0	8,690,912	
Prepayments	1,365,241	21,567	1,343,674	Statement E
Other	423,894	123,984	299,910	Statement E
Total Additions	11,530,367	546,090	10,984,277	
Total Before Deductions	$85,859,076	$24,139,345	$61,719,731	
Deductions				
Accumulated Deferred Income Taxes	10,901,602	4,271,992	6,629,610	Statement K
Accumulated Investment Tax Credits	601,555	273,540	328,015	Statement K
Customer Advances	561,257	267,859	293,398	Statement E
Total Deductions	12,064,414	4,813,391	7,251,023	
Total Rate Base	$73,794,662	$19,325,954	$54,468,708	

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2001

	2000	2001	Average
Gas Plant in Service	$68,252,685	$69,322,207	$68,787,446
Accumulated Reserve for Depreciation	43,364,797	45,893,985	44,629,391
Net Gas Plant in Service	24,887,888	23,428,222	24,158,055
CWIP in Service Pending Reclassification	168,681	165,033	166,857
Total Gas Plant in Service	25,056,569	23,593,255	24,324,912
Additions			
Materials and Supplies	421,395	381,856	401,626
Fuel Stock	23,466	18,683	21,075
Prepayments	17,123	21,567	19,345
Other	176,984	123,984	150,484
Total Additions	638,968	546,090	592,530
Total Before Deductions	$25,695,537	$24,139,345	$24,917,442
Deductions			
Accumulated Deferred Income Taxes	4,321,340	4,271,992	4,296,666
Accumulated Investment Tax Credits	306,663	273,540	290,102
Customer Advances	485,978	267,859	376,919
Total Deductions	5,113,981	4,813,391	4,963,687
Total Rate Base	$20,581,556	$19,325,954	$19,953,755

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - NORTH DAKOTA
(000s)

	Before Additional Revenue Requirements 1/	Additional Revenue Requirements	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$67,962	**$2,840**	$70,802
Transportation	900		900
Other	287		287
Total Revenues	69,149	2,840	71,989
Operating Expenses			
Operation and Maintenance			
Cost of Gas	50,072		50,072
Other O&M	14,354		14,354
Total O&M	64,426		64,426
Depreciation	3,261		3,261
Taxes Other Than Income	1,352		1,352
Current Income Taxes	(1,961)	1,125	(836)
Deferred Income Taxes	1,612		1,612
Total Expenses	68,690	1,125	69,815
Operating Income	$459	$1,715	$2,174
Rate Base	$19,681		$19,681
Rate of Return	**2.332%**		**11.044%**

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA

Customer Class/Rate	Projected 2003 Bills	Projected 2003 Dk	Projected 2003 Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	878,101	7,899,840	$39,198,383	$40,988,358	$1,789,975	4.6%
Firm General Service - Rate 70	135,039	5,609,220	24,779,326	25,914,843	1,135,517	4.6%
Air Force - Rate 64						
Firm	12	36,450	132,624	132,621		
Interruptible	24	1,014,790	2,448,094	2,448,235		
Total Air Force	36	1,051,240	2,580,718	2,580,856	138	0.0%
Small Interruptible						
Sales - Rate 71	852	489,700	1,403,132			
Transport - Rate 81	860	1,030,440	557,408			
Total Small Interruptible	1,712	1,520,140	1,960,540	1,879,181	(81,359)	-4.1%
Large Interruptible						
Sales - Rate 85	0	0	0			
Transport - Rate 82	108	2,246,820	342,735			
Total Large Interruptible	108	2,246,820	342,735	342,596	(139)	0.0%
Total North Dakota	1,014,996	18,327,260	$68,861,702	$71,705,834	$2,844,132	4.1%

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CLASS COST OF SERVICE STUDY

Part A – Reports

Part B – Allocation Assignment Report

Part C – Allocation Factor Report

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Cost of Service By Component	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Firm General Demand	Firm General Energy	Firm General Customer
Rate Base	19,325,956	3,382,639	71,834	8,234,138	2,309,708	58,084	4,630,641
Operating Income for Proposed Return	2,134,357	373,579	7,933	909,378	255,084	6,415	511,408
Current Operating Income	1,244,450	(800,666)	3,337,906	(2,176,914)	(546,700)	2,410,468	(1,584,645)
Increase in Operating Income	889,907	1,174,245	(3,329,973)	3,086,292	801,784	(2,404,053)	2,096,053
Related Taxes for Increase							
Federal Income	583,695	770,191	(2,184,140)	2,024,309	525,893	(1,576,826)	1,374,808
Total Increase in Revenue	1,473,602	1,944,436	(5,514,113)	5,110,601	1,327,677	(3,980,879)	3,470,861
Adjusted Revenue Before Increase	67,635,478	12,253,533	20,273,025	5,865,510	8,366,885	14,507,979	1,552,938
Total Cost of Service Required From Rates	69,109,080	14,197,969	14,758,912	10,976,111	9,694,562	10,527,100	5,023,799
Less Cost of Gas Items Recovered thru PGA	48,776,394	12,207,455	14,577,663	0	8,335,422	10,381,976	0
Net Distribution Costs	20,332,686	1,990,514	181,249	10,976,111	1,359,140	145,124	5,023,799
Billing Units at Customer							
Dk Throughput	35,875,902	7,681,994	7,681,994	0	5,470,992	5,470,992	0
Bills	993,588	0	0	859,416	0	0	132,276
Peak Day Dk Demand	200,723	114,254	0	0	78,014	0	0
Unit Cost of Service							
$ Per Dk		0.259	0.024	0.000	0.248	0.027	0.000
$ Per Customer Per Month		0.000	0.000	12.772	0.000	0.000	37.980

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Cost of Service By Component	Air Force			Small Interruptible Sales		
	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base	75,111	8,609	68,485	38,488	4,141	116,489
Operating Income for Proposed Return	8,295	951	7,563	4,251	457	12,865
Current Operating Income	(17,779)	109,703	(15,394)	(9,095)	180,077	(37,336)
Increase in Operating Income	26,074	(108,752)	22,957	13,346	(179,620)	50,201
Related Taxes for Increase						
Federal Income	17,102	(71,331)	15,058	8,754	(117,813)	32,927
Total Increase in Revenue	43,176	(180,083)	38,015	22,100	(297,433)	83,128
Adjusted Revenue Before Increase	272,125	2,222,457	10,688	142,218	1,231,675	31,356
Total Cost of Service Required From Rates	315,301	2,042,374	48,703	164,318	934,242	114,484
Less Cost of Gas Items Recovered thru PGA	271,101	1,931,807	0	141,695	929,275	0
Net Distribution Costs	44,200	110,567	48,703	22,623	4,967	114,484
Billing Units at Customer						
Dk Throughput	1,018,005	1,018,005	0	489,700	489,700	0
Bills	0	0	36	0	0	888
Peak Day Dk Demand	2,537	0	0	1,300	0	0
Unit Cost of Service						
$ Per Dk	0.043	0.109	0.000	0.046	0.010	0.000
$ Per Customer Per Month	0.000	0.000	1,352.861	0.000	0.000	128.923

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Cost of Service By Component	Small Interruptible Transport			Large Interruptible Sales		
	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base	74,458	0	76,650	0	0	0
Operating Income for Proposed Return	8,223	0	8,465	0	0	0
Current Operating Income	(18,860)	286,245	(11,352)	0	(515)	(39)
Increase in Operating Income	27,083	(286,245)	19,817	0	515	39
Related Taxes for Increase						
Federal Income	17,764	(187,749)	12,998	0	338	26
Total Increase in Revenue	44,847	(473,994)	32,815	0	853	65
Adjusted Revenue Before Increase	1,001	484,329	74,748	0	0	0
Total Cost of Service Required From Rates	45,848	10,335	107,563	0	853	65
Less Cost of Gas Items Recovered thru PGA	0	0	0	0	0	0
Net Distribution Costs	45,848	10,335	107,563	0	853	65
Billing Units at Customer						
Dk Throughput	1,030,440	1,030,440	0	0	0	0
Bills	0	0	864	0	0	0
Peak Day Dk Demand	2,515	0	0	0	0	0
Unit Cost of Service						
$ Per Dk	0.044	0.010	0.000	0.000	0.000	0.000
$ Per Customer Per Month	0.000	0.000	124.494	0.000	0.000	0.000

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Cost of Service By Component	Large Interruptible Transport Demand	Energy	Customer
Rate Base	62,261	0	114,220
Operating Income for Proposed Return	6,876	0	12,614
Current Operating Income	(15,772)	156,626	(1,508)
Increase in Operating Income	22,648	(156,626)	14,122
Related Taxes for Increase			
Federal Income	14,855	(102,732)	9,263
Total Increase in Revenue	37,503	(259,358)	23,385
Adjusted Revenue Before Increase	837	288,759	55,415
Total Cost of Service Required From Rates	38,340	29,401	78,800
Less Cost of Gas Items Recovered thru PGA	0	0	0
Net Distribution Costs	38,340	29,401	78,800
Billing Units at Customer			
Dk Throughput	2,246,820	2,246,820	0
Bills	0	0	108
Peak Day Dk Demand	2,103	0	0
Unit Cost of Service			
$ Per Dk	0.017	0.013	0.000
$ Per Customer Per Month	0.000	0.000	729.630

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
SUMMARY REPORT
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Operating Income and Rate of Return	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible
Operating Revenues	95,413,770	52,600,065	34,733,966	4,932,194	1,944,932	621,741	580,872
Elimination of Unbilled Revenues	6,333,652	3,534,224	2,335,226	332,402	130,989	0	811
Adjustment to Operating Revenues	(34,111,944)	(17,742,221)	(12,641,390)	(2,759,326)	(670,672)	(61,663)	(236,672)
Adjusted Operating Revenues	67,635,478	38,392,068	24,427,802	2,505,270	1,405,249	560,078	345,011
Operating Expenses							
Cost of Gas	77,058,145	42,310,356	29,567,926	3,485,448	1,694,415	0	0
Adjustment to Cost of Gas	(28,065,930)	(15,412,151)	(10,769,989)	(1,267,554)	(616,236)	0	0
Other O&M Expense	12,722,666	8,574,333	3,836,443	55,939	83,356	95,267	77,328
Total Operation & Maint. Exp.	61,714,881	35,472,538	22,634,380	2,273,833	1,161,535	95,267	77,328
Depreciation	3,059,362	1,866,585	1,108,720	15,274	23,771	29,473	15,539
Taxes Other Than Income Taxes	1,225,454	789,603	402,193	6,536	8,624	10,527	7,971
Fed. & State Inc. Taxes - Current	4,322,348	1,600,351	1,341,490	817,236	185,024	190,359	187,888
Tax Effect of Adjustments	100,673	421,454	162,339	(405,779)	26,794	(21,583)	(82,552)
Deferred Income Taxes	(4,031,690)	(2,118,789)	(1,500,443)	(278,360)	(134,145)	2	45
Total Operating Expenses	66,391,028	38,031,742	24,148,679	2,428,740	1,271,603	304,045	206,219
Operating Income	1,244,450	360,326	279,123	76,530	133,646	256,033	138,792
Rate Base	19,325,956	11,688,611	6,998,433	152,205	159,118	151,108	176,481
Rate of Return	6.439%	3.083%	3.988%	50.281%	83.992%	169.437%	78.644%

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATING REVENUES
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Operating Revenues	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Residential	55,953,876	55,953,876	0	0	0	0	0	0
Firm General	36,971,326	0	36,971,326	0	0	0	0	0
Air Force	5,262,573	0	0	5,262,573	0	0	0	0
Small Interruptible Sales	2,073,804	0	0	0	2,073,804	0	0	0
Small Interruptible Transportation	619,071	0	0	0	0	619,071	0	0
Large Interruptible Sales	12,839	0	0	0	0	0	12,839	0
Large Interruptible Transportation	566,568	0	0	0	0	0	0	566,568
Unbilled Revenue	(6,333,652)	(3,534,224)	(2,335,226)	(332,402)	(130,989)	0	(811)	0
Total Gas Sales and Transport Revenue	95,126,405	52,419,652	34,636,100	4,930,171	1,942,815	619,071	12,028	566,568
Other Operating Revenue								
Miscellaneous								
Reconnect Fees								
Seasonal	4,466	3,870	596	0	0	0	0	0
Non-Payment Disconnect	10,396	9,009	1,387	0	0	0	0	0
NSF Check Fees	7,818	6,775	1,043	0	0	0	0	0
Work for Contractors, Municipal & Others	55,320	33,525	19,912	399	436	566	0	482
Energy Diversion	0	0	0	0	0	0	0	0
CNG Compression & O&M Charges	(587)	(356)	(212)	(4)	(4)	(6)	0	(5)
Rent From Gas Property	198,260	120,152	71,363	1,427	1,565	2,024	0	1,729
Other Gas Revenues								
Sundry Junk	421	259	150	3	3	4	0	2
Operating/Construction Material	614	377	219	4	4	6	0	4
Patronage Dividends	3,052	2,057	921	13	20	22	0	19
Miscellaneous	4,502	3,035	1,358	20	29	33	0	27
Transport and Penalty Revenue - Net	3,103	1,710	1,129	161	64	21	0	18
Total Other Operating Revenue	287,365	180,413	97,866	2,023	2,117	2,670	0	2,276
Total Gas Operating Revenues	95,413,770	52,600,065	34,733,966	4,932,194	1,944,932	621,741	12,028	568,844

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATION & MAINTENANCE EXPENSES
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Operation and Maintenance Expenses	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Cost of Gas Items								
Cost of Purchased Gas	76,842,324	42,197,269	29,487,387	3,470,462	1,687,206	0	0	0
Other Gas Supply Expenses	215,821	113,087	80,539	14,986	7,209	0	0	0
Total Cost of Gas Items	77,058,145	42,310,356	29,567,926	3,485,448	1,694,415	0	0	0
Distribution Expenses								
Operation								
Load Dispatch	70,675	30,267	21,556	4,011	1,929	4,060	0	8,852
Mains and Services	878,936	560,547	295,911	4,916	5,626	7,849	0	4,087
Measuring Stations - General	35,628	23,874	10,484	581	157	294	0	238
Measuring Stations - Industrial	37,387	6,221	5,357	9,559	476	596	0	15,178
Measuring Stations - City Gate	7,256	4,436	2,235	53	29	459	0	44
Meters & House Regulators	585,681	322,702	249,599	0	6,544	6,682	0	154
Customer Installations	760,312	420,497	323,835	0	8,160	7,820	0	0
Other Gas Distribution	1,421,149	825,045	547,093	9,314	12,941	14,611	0	12,145
Rents	20,705	12,021	7,971	136	188	212	0	177
Supervision & Engineering	516,163	299,656	198,705	3,383	4,701	5,307	0	4,411
Total Operation Expense	4,333,892	2,505,266	1,662,746	31,953	40,751	47,890	0	45,286
Maintenance								
Structures & Improvements	2,316	1,115	543	185	8	14	0	451
Mains	118,089	79,790	35,038	956	527	983	0	795
Measuring Stations - General	25,142	16,847	7,398	410	111	208	0	168
Measuring Stations - Industrial	4,593	764	658	1,174	59	73	0	1,865
Measuring Stations - City Gate	410	251	126	3	2	26	0	2
Services	116,078	64,198	49,440	0	1,246	1,194	0	0
Meters & House Regulators	103,235	56,881	43,996	0	1,153	1,178	0	27
Other Equipment	185,732	110,530	69,056	1,285	1,566	1,851	0	1,444
Supervision & Engineering	272,457	162,142	101,301	1,886	2,296	2,714	0	2,118
Total Maintenance Expense	828,052	492,518	307,556	5,899	6,968	8,241	0	6,870
Total Distribution Expenses	5,161,944	2,997,784	1,970,302	37,852	47,719	56,131	0	52,156

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATION & MAINTENANCE EXPENSES
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Operation and Maintenance Expenses	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Customer Accounts	229,995	198,937	30,619	8	206	200	0	25
Meter Reading	583,211	322,550	248,404	0	6,259	5,998	0	0
Customer Records & Collection	1,519,399	1,314,223	202,277	55	1,358	1,321	0	165
Uncollectible Accounts	343,492	297,108	45,729	12	307	299	0	37
Miscellaneous Customer Accounts	158,847	137,397	21,147	6	142	138	0	17
Customer Service & Information	165,359	143,029	22,014	6	148	144	0	18
Sales Expenses	470,361	406,845	62,619	17	420	409	0	51
Administration & General Expenses	4,090,058	2,756,460	1,233,332	17,983	26,797	30,627	0	24,859
Total Gas O&M Expenses	89,780,811	50,884,689	33,404,369	3,541,387	1,777,771	95,267	0	77,328
O&M Excl. Gas Cost and A&G	8,632,608	5,817,873	2,603,111	37,956	56,559	64,640	0	52,469
O&M Excl. Cost of Gas	12,722,666	8,574,333	3,836,443	55,939	83,356	95,267	0	77,328

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
DEPRECIATION EXPENSE
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Depreciation Expense	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Distribution Plant								
Mains	1,122,277	758,297	332,986	9,088	5,009	9,342	0	7,555
Structures	4,325	2,081	1,015	347	14	26	0	842
Meas. & Reg. Sta. General	11,908	7,979	3,504	194	53	99	0	79
Meas. & Reg. Sta. - City Gate	4,768	2,914	1,469	35	19	302	0	29
Services	980,295	542,160	417,531	0	10,521	10,083	0	0
Meters	301,513	166,754	128,422	0	3,236	3,101	0	0
Service Regulators	38,944	20,881	16,665	0	558	757	0	83
Measuring & Reg. Eqpt. - Indust.	7,084	1,179	1,015	1,811	90	113	0	2,876
Other Property on Cust. Prem.	10,741	7,258	3,187	87	48	89	0	72
Other Equipment	39,474	26,671	11,712	319	177	329	0	266
Land Rights	1,152	779	342	9	5	9	0	8
Total Distribution Plant	2,522,481	1,536,953	917,848	11,890	19,730	24,250	0	11,810
General Plant	127,854	78,484	45,470	805	963	1,244	0	888
Amort. of Intangible Plant - General	2,513	1,542	893	16	19	25	0	18
Common Plant	220,057	135,083	78,261	1,386	1,658	2,141	0	1,528
Amort. of Intangible Plant - Common	185,395	113,805	65,933	1,168	1,397	1,804	0	1,288
Gas Plant Leased to Others	1,062	718	315	9	4	9	0	7
Total Depreciation Expense	3,059,362	1,866,585	1,108,720	15,274	23,771	29,473	0	15,539

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
TAXES OTHER THAN INCOME TAXES
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Taxes Other Than Income	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Ad Valorem Taxes								
Distribution Plant	489,086	300,227	173,939	3,080	3,686	4,757	0	3,397
General Plant/Intangible	52,125	31,997	18,538	328	393	507	0	362
Common Plant/Intangible	62,618	38,438	22,269	395	472	609	0	435
Total Ad Valorem Taxes	603,829	370,662	214,746	3,803	4,551	5,873	0	4,194
Other Taxes - Payroll, Franchise, Other	621,625	418,941	187,447	2,733	4,073	4,654	0	3,777
Total Taxes Other Than Income	1,225,454	789,603	402,193	6,536	8,624	10,527	0	7,971

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
INCOME TAXES
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Income Taxes	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transp.	Large Interruptible Sales	Large Interruptible Transp.
Operating Revenue	95,413,770	52,600,065	34,733,966	4,932,194	1,944,932	621,741	12,028	568,844
Operation & Maintenance Expense	89,780,811	50,884,689	33,404,369	3,541,387	1,777,771	95,267	0	77,328
Depreciation Expense	3,059,362	1,866,585	1,108,720	15,274	23,771	29,473	0	15,539
Taxes Other Than Income	1,225,454	789,603	402,193	6,536	8,624	10,527	0	7,971
Total Operating Expense	94,065,627	53,540,877	34,915,282	3,563,197	1,810,166	135,267	0	100,838
Interest Expense	1,013,655	614,313	364,856	7,297	8,002	10,356	0	8,831
Total Expenses	95,079,282	54,155,190	35,280,138	3,570,494	1,818,168	145,623	0	109,669
Taxable Income Before Adjustments	334,488	(1,555,125)	(546,172)	1,361,700	126,764	476,118	12,028	459,175
Tax Deductions								
Management Incentive Compensation	(67,648)	(41,526)	(24,058)	(426)	(510)	(658)	0	(470)
Pension Expense	747,827	459,064	265,949	4,709	5,636	7,275	0	5,194
Sundry Reserves	5,536	3,398	1,969	35	42	53	0	39
Reserve For Deferred Maintenance	5,815	3,569	2,067	37	44	57	0	41
Property Insurance Adjustment	(21,165)	(12,993)	(7,526)	(134)	(159)	(206)	0	(147)
Bad Debt Expense	33,706	18,574	12,273	1,747	688	219	4	201
Accrued Vacation	55,460	37,377	16,723	244	363	416	0	337
Capitalized Overheads	(375,818)	(230,701)	(133,652)	(2,367)	(2,833)	(3,655)	0	(2,610)
Customer Advances	67,468	58,469	8,999	0	0	0	0	0
Restricted Stock Bonus Plan	56,295	37,939	16,976	247	370	421	0	342
FAS 106 - OPRB	33,145	22,337	9,995	145	217	249	0	202
Deferred Compensation-Directors	(17,261)	(11,632)	(5,205)	(76)	(113)	(129)	0	(106)
Board of Directors - Retirement Benefits	(263,746)	(177,750)	(79,531)	(1,160)	(1,728)	(1,975)	0	(1,602)
Demand Charges	17,742	9,752	6,673	442	114	239	0	522
PCB Related Income	(4,985)	(3,060)	(1,773)	(31)	(38)	(48)	0	(35)
Plant Reclassification	(7,679)	(4,713)	(2,731)	(49)	(58)	(75)	0	(53)
Liberalized Depreciation & OPTD	(552,874)	(339,389)	(196,618)	(3,482)	(4,167)	(5,378)	0	(3,840)
Contributions in Aid of Construction	(42,068)	(36,457)	(5,611)	0	0	0	0	0
Purchased Gas Cost Adjustment	(10,095,293)	(5,289,790)	(3,767,303)	(700,994)	(337,206)	0	0	0

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
INCOME TAXES
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Income Taxes	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transp.	Large Interruptible Sales	Large Interruptible Transp.
Amort. of Loss on Bond Retirements	(106,848)	(64,755)	(38,459)	(769)	(843)	(1,091)	0	(931)
FAS 106 - Deferred Expense	(56,331)	(37,962)	(16,987)	(247)	(370)	(422)	0	(343)
Gas IRP	(53,001)	(32,120)	(19,077)	(381)	(419)	(542)	0	(462)
Disallowed Meals & Entertainment	(25,610)	(17,259)	(7,722)	(113)	(168)	(192)	0	(156)
Federal Non-Hwy. Use Tax Credit	(3,860)	(2,369)	(1,373)	(25)	(29)	(37)	0	(27)
Preferred Dividend Paid Deduction	13,572	8,331	4,827	85	103	132	0	94
Total Deductions & Adjustments	(10,657,621)	(5,643,666)	(3,961,175)	(702,563)	(341,064)	(5,347)	4	(3,810)
Taxable Income (Before State Income Tax)	10,992,109	4,088,541	3,415,003	2,064,263	467,828	481,465	12,024	462,985
Less: State Income Tax	861,216	320,332	267,560	161,732	36,654	37,722	942	36,274
Federal Taxable Income	10,130,893	3,768,209	3,147,443	1,902,531	431,174	443,743	11,082	426,711
Federal Income Tax @ Current Rate	3,545,814	1,318,873	1,101,605	665,887	150,911	155,310	3,879	149,349
Plus: State Income Tax	861,216	320,332	267,560	161,732	36,654	37,722	942	36,274
Plus: Credits & Adjustments	(54,273)	(20,187)	(16,861)	(10,192)	(2,311)	(2,377)	(59)	(2,286)
Federal and State Income Taxes	4,352,757	1,619,018	1,352,304	817,427	185,254	190,655	4,762	183,337
Rounding & Prior Year Adjustments	(30,409)	(18,667)	(10,814)	(191)	(230)	(296)	0	(211)
Federal Income Tax Computed	4,322,348	1,600,351	1,341,490	817,236	185,024	190,359	4,762	183,126

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
DEFERRED INCOME TAXES
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Deferred Income Taxes	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Management Incentive Compensation	(26,796)	(16,449)	(9,529)	(169)	(202)	(261)	0	(186)
Pension Expense	296,216	181,836	105,343	1,866	2,232	2,882	0	2,057
Sundry Reserves	2,190	1,345	779	13	17	21	0	15
Reserve For Deferred Maintenance	2,236	1,372	795	15	17	21	0	16
Property Insurance Adjustment	(8,386)	(5,147)	(2,982)	(53)	(63)	(82)	0	(59)
Bad Debt Expense	13,352	7,358	4,862	691	272	87	2	80
Accrued Vacation	21,968	14,805	6,624	97	144	164	0	134
Capitalized Overheads	(148,861)	(91,380)	(52,939)	(938)	(1,122)	(1,448)	0	(1,034)
Customer Advances	26,724	23,159	3,565	0	0	0	0	0
Restricted Stock Bonus Plan	22,299	15,028	6,724	97	147	167	0	136
FAS 106 - OPRB	13,504	9,101	4,073	60	88	100	0	82
Deferred Compensation - Directors	(6,835)	(4,607)	(2,061)	(30)	(45)	(51)	0	(41)
Board of Directors - Retirement Benefits	(104,470)	(70,406)	(31,503)	(460)	(684)	(782)	0	(635)
Demand Charges	7,028	3,863	2,643	175	45	95	0	207
PCB Related Income	(3,080)	(1,891)	(1,096)	(19)	(23)	(30)	0	(21)
Asbestos Related Income	0	0	0	0	0	0	0	0
Liberalized Deprec. & Oth. Prop. Tim. Diff.	(36,824)	(22,605)	(13,096)	(231)	(278)	(358)	0	(256)
Contributions in Aid of Construction	(25,346)	(21,965)	(3,381)	0	0	0	0	0
ND - Normalized Timing Differences	(56,328)	(34,577)	(20,032)	(355)	(424)	(548)	0	(392)
Unrecovered Purchased Gas Costs	(3,998,746)	(2,095,286)	(1,492,229)	(277,664)	(133,567)	0	0	0
Rate Case Expense	0	0	0	0	0	0	0	0
Amort. of Loss on Bond Retirements	(42,323)	(25,650)	(15,234)	(304)	(334)	(432)	0	(369)
FAS 106 Deferred Expense	(22,313)	(15,038)	(6,728)	(97)	(147)	(167)	0	(136)
Gas IRP	(20,993)	(11,000)	(7,834)	(1,458)	(701)	0	0	0
Closing/Filing and Out of Period	64,094	39,345	22,793	404	483	624	0	445
Total Gas Charges	(4,031,690)	(2,118,789)	(1,500,443)	(278,360)	(134,145)	2	2	43
Accumulated Balance 12/31/01	(4,271,991)	(2,622,418)	(1,519,248)	(26,904)	(32,194)	(41,555)	0	(29,672)

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PLANT IN SERVICE
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Plant in Service	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Distribution Plant								
Mains	27,079,883	18,297,260	8,034,767	219,292	120,859	225,407	0	182,298
Structures & Improvements	180,117	86,672	42,278	14,445	573	1,068	0	35,081
Meas. & Reg. Sta. Eqpt. - General	520,093	348,511	153,040	8,474	2,302	4,293	0	3,473
Meas. & Reg. Sta. Eqpt. - City Gate	174,001	106,366	53,595	1,274	703	11,003	0	1,060
Service Regulators	1,677,415	899,393	717,794	0	24,027	32,605	0	3,596
Indust. Meas. & Reg. Sta. Eqpt.	371,029	61,737	53,166	94,866	4,730	5,910	0	150,620
Services	12,124,678	6,705,652	5,164,194	0	130,127	124,705	0	0
Meters	11,983,141	6,627,373	5,103,910	0	128,608	123,250	0	0
Other Property on Cust. Premises	1,681	1,135	499	14	8	14	0	11
CNG Refueling Station	113,208	76,492	33,589	917	505	943	0	762
Cathodic Protection	443,740	299,826	131,661	3,593	1,980	3,693	0	2,987
Other Equipment	331,597	224,053	98,388	2,685	1,479	2,760	0	2,232
Land & Land Rights	86,524	58,462	25,672	701	387	720	0	582
Land & Land Rights - Common	208,685	141,004	61,918	1,690	931	1,737	0	1,405
Land & Land Rights - General	154,459	104,365	45,829	1,250	689	1,286	0	1,040
Total Distribution Plant	55,450,251	34,038,301	19,720,300	349,201	417,908	539,394	0	385,147
General Plant	6,772,598	4,157,379	2,408,603	42,651	51,043	65,881	0	47,041
Intangible Plant - General	207,216	127,200	73,694	1,305	1,562	2,015	0	1,440
Common Plant	4,969,608	3,050,609	1,767,389	31,297	37,454	48,342	0	34,517
Intangible Plant - Common	1,813,894	1,113,464	645,093	11,423	13,671	17,644	0	12,599
Gas Plant Leased to Others	11,374	7,686	3,375	92	51	94	0	76
Acquisition Adjustment	97,267	59,707	34,592	613	733	946	0	676
Total Gas Plant in Service	69,322,208	42,554,346	24,653,046	436,582	522,422	674,316	0	481,496

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ACCUMULATED RESERVE FOR DEPRECIATION
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Accumulated Reserve for Depreciation	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Distribution Plant								
Mains	20,582,530	13,907,146	6,106,962	166,677	91,861	171,325	0	138,559
Structures & Improvements	101,152	48,674	23,743	8,112	322	600	0	19,701
Meas. & Reg. Sta. Equip. - General	261,901	175,498	77,065	4,267	1,160	2,162	0	1,749
Meas. & Reg. Sta. Equip. - City Gate	48,134	29,424	14,826	352	195	3,044	0	293
Services	12,202,942	6,748,937	5,197,528	0	130,967	125,510	0	0
Meters	4,364,019	2,413,556	1,858,741	0	46,837	44,885	0	0
Service Regulators	642,471	344,479	274,924	0	9,203	12,488	0	1,377
Indust. Meas. & Reg. Sta. Eqpt.	156,443	26,031	22,417	40,000	1,995	2,492	0	63,508
Other Property on Customer Prem.	747	505	222	6	3	6	0	5
CNG Refueling Station	82,301	55,609	24,419	667	367	685	0	554
Cathodic Protection	197,290	133,304	58,537	1,598	881	1,642	0	1,328
Other Equipment	286,962	193,894	85,144	2,324	1,280	2,388	0	1,932
Land Rights	30,884	20,868	9,163	250	138	257	0	208
Total Distribution Reserve	38,957,776	24,097,925	13,753,691	224,253	285,209	367,484	0	229,214
General Plant	3,498,223	2,147,395	1,244,106	22,030	26,365	34,029	0	24,298
Intangible Plant - General	197,932	121,501	70,393	1,246	1,492	1,925	0	1,375
Common Plant	2,592,531	1,591,432	922,006	16,327	19,539	25,219	0	18,008
Intangible Plant - Common	643,891	395,254	228,993	4,055	4,853	6,264	0	4,472
Gas Plant Leased to Others	3,633	2,456	1,078	29	16	30	0	24
Total Accumulated Reserve for Depreciation	45,893,986	28,355,963	16,220,267	267,940	337,474	434,951	0	277,391

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
CONSTRUCTION WORK IN PROGRESS
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Construction Work in Progress	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
CWIP in Service Pending Classification	165,034	101,306	58,692	1,040	1,244	1,606	0	1,146
Total Construction Work in Progress in Service Pending Classification	165,034	101,306	58,692	1,040	1,244	1,606	0	1,146

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
WORKING CAPITAL
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Working Capital	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Materials & Supplies	381,858	234,404	135,803	2,405	2,878	3,715	0	2,653
Prepaid Insurance	21,565	13,239	7,670	136	162	209	0	149
Unamortized Gas IRP Costs - Other	123,985	64,967	46,268	8,609	4,141	0	0	0
Fuel Stocks	18,683	6,867	11,816	0	0	0	0	0

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
RATE BASE REPORT
PER BOOKS
TWELVE MONTHS ENDED DECEMBER 31, 2001

Rate Base	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible Sales	Large Interruptible Transport
Gas Plant in Service	69,322,208	42,554,346	24,653,046	436,582	522,422	674,316	0	481,496
Less: Accumulated Depreciation	45,893,986	28,355,963	16,220,267	267,940	337,474	434,951	0	277,391
Net Gas Plant in Service	23,428,222	14,198,383	8,432,779	168,642	184,948	239,365	0	204,105
CWIP in Service	165,034	101,306	58,692	1,040	1,244	1,606	0	1,146
Total Plant	23,593,256	14,299,689	8,491,471	169,682	186,192	240,971	0	205,251
Additions								
Materials & Supplies	381,858	234,404	135,803	2,405	2,878	3,715	0	2,653
Fuel Stocks	18,683	6,867	11,816	0	0	0	0	0
Prepaid Insurance	21,565	13,239	7,670	136	162	209	0	149
Unamortized Gas IRP Costs	123,985	64,967	46,268	8,609	4,141	0	0	0
Total Additions	546,091	319,477	201,557	11,150	7,181	3,924	0	2,802
Total Before Deductions	24,139,347	14,619,166	8,693,028	180,832	193,373	244,895	0	208,053
Deductions								
Accumulated Deferred Income Tax	(4,271,991)	(2,622,418)	(1,519,248)	(26,904)	(32,194)	(41,555)	0	(29,672)
Investment Tax Credit Balance	(273,541)	(167,917)	(97,279)	(1,723)	(2,061)	(2,661)	0	(1,900)
Customer Advances For Constr.	(267,859)	(140,220)	(78,068)	0	0	(49,571)	0	0
Total Deductions	(4,813,391)	(2,930,555)	(1,694,595)	(28,627)	(34,255)	(93,787)	0	(31,572)
Total Rate Base	19,325,956	11,688,611	6,998,433	152,205	159,118	151,108	0	176,481

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

	LINE ITEM		ALLOCATION FACTOR	
	PLANT IN SERVICE:			
375	Structures & Improvements	128,275	13	Distribution Mains
		4,218		Direct to Firm General Customer
		13,406		Direct to Air Force Customer
		34,218		Direct to Large Int. Transport Customer
376	Mains	9,748,758	9	Average Customers @ Distribution
		17,331,125	5	2-Day Peak @ Distribution
378	Meas. & Reg. Sta. Equip. - General	515,796	13	Distribution Mains
		4,297		Direct to Air Force Customer
379	Meas. & Reg. Sta. Equip. - City Gate	157,422	13	Distribution Mains
		6,887		Direct to Firm General Customer
		9,693		Direct to Small Int. Transport Customer
383	Service Regulators	1,626,217	10	Wtd. Customers @ Distrib. Excl. AF & LI
		25,149		Direct to Firm General Customer
		6,574		Direct to Small Int. Sales Customer
		15,879		Direct to Small Int. Transport Customer
		3,596		Direct to Large Int. Transport Customer
385	Indust. Meas. & Reg. Sta. Equip.	91,370	13	Distribution Mains
		26,056		Direct to Firm General Customer
		94,126		Direct to Air Force Customer
		4,322		Direct to Small Int. Sales Customer
		5,149		Direct to Small Int. Transport Customer
		150,005		Direct to Large Int. Transport Customer
380	Services	12,124,678	10	Wtd. Customers @ Distrib. Excl. AF & LI
381	Meters	11,983,141	10	Wtd. Customers @ Distrib. Excl. AF & LI
386.1	Other Property on Customer's Premises	1,680	13	Distribution Mains
386.2	CNG Refueling Station	113,207	13	Distribution Mains
386.3	Gas Plant Leased to Others	11,374	13	Distribution Mains
387.1	Cathodic Protection	443,741	13	Distribution Mains
387.2	Other Equipment	331,598	13	Distribution Mains
374	Land & Land Rights	86,523	13	Distribution Mains
389	Land & Land Rights - Common	208,685	13	Distribution Mains
389	Land & Land Rights - General	154,460	13	Distribution Mains
	General Plant	6,772,597	15	Distribution Plant
	Intangible Plant - General	207,216	15	Distribution Plant
	Common Plant	4,969,608	15	Distribution Plant
	Intangible Plant - Common	1,813,895	15	Distribution Plant
114.2	Acquisition Adjustment - Propane	97,266	15	Distribution Plant
	ACCUMULATED RESERVE FOR DEPRECIATION REPORT:			
376	Mains	20,582,529	13	Distribution Mains
375	Structures & Improvements	101,150	17	Structures & Improvements
378	Meas. & Reg. Sta. Equip. - General	261,901	18	Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. Equip. - City Gate	48,134	19	Meas. & Reg. Eqpt.- City Gate
380	Services	12,202,943	10	Wtd. Customers @ Distrib. Excl. AF & LI
381	Meters	4,364,018	10	Wtd. Customers @ Distrib. Excl. AF & LI
383	Service Regulators	642,471	20	Service Regulators
385	Indust. Meas. & Reg. Sta. Equip.	156,443	21	Ind. Meas. & Reg. Sta. Eqpt.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

	LINE ITEM		ALLOCATION FACTOR	
386.1	Other Property on Cust Prem.	748	13	Distribution Mains
386.2	CNG Refueling Station	82,301	13	Distribution Mains
386.3	Gas Plant Leased to Others	3,634	13	Distribution Mains
387.1	Cathodic Protection	197,290	13	Distribution Mains
387.2	Other Equipment	286,962	13	Distribution Mains
374.2	Land Rights	30,884	13	Distribution Mains
	General Plant	3,498,224	15	Distribution Plant
	Intangible Plant - General	197,933	15	Distribution Plant
	Common Plant	2,592,530	15	Distribution Plant
	Intangible Plant - Common	643,890	15	Distribution Plant
	CONSTRUCTION WORK IN PROGRESS REPORT:			
	CWIP in Service pending Classification	165,033	15	Distribution Plant
	OPERATING REVENUE REPORT:			
	Residential	19,231,623		Direct to Residential Demand
		30,990,104		Direct to Residential Energy
		5,732,149		Direct to Residential Customer
	Firm General	13,131,623		Direct to Firm General Demand
		22,352,466		Direct to Firm General Energy
		1,487,237		Direct to Firm General Customer
	Air Force	427,093		Direct to Air Force Demand
		4,825,640		Direct to Air Force Energy
		9,840		Direct to Air Force Customer
	Small Interruptible Sales	223,226		Direct to Small Int. Sales Demand
		1,819,393		Direct to Small Int. Sales Energy
		31,185		Direct to Small Int. Sales Customer
	Small Interruptible Transportation	538,661		Direct to Small Int. Transport Energy
		80,410		Direct to Small Int. Transport Customer
	Large Interruptible Sales	0		Direct to Large Int. Sales Demand
		11,939		Direct to Large Int. Sales Energy
		900		Direct to Large Int. Sales Customer
	Large Interruptible Transportation	495,568		Direct to Large Int. Transport Energy
		71,000		Direct to Large Int. Transport Customer
	Unbilled Revenue	(6,333,648)	26	Sales Revenue
	Other Operating Revenue			
	Reconnect Fees			
	Seasonal	4,466	11	Average Res. & Firm General Cust.
	Non-Payment Disconnect	10,396	11	Average Res. & Firm General Cust.
	NSF Check Fees	7,818	11	Average Res. & Firm General Cust.
	Work for Contractors, Municipalities & Others	55,318	24	Net Gas Plant in Service
	Energy Diversion	0	24	Net Gas Plant in Service
	CNG Compression & O&M Charges	(588)	24	Net Gas Plant in Service
	Rent From Gas Property			
	Buildings	22,375	24	Net Gas Plant in Service
	Equipment	17,051	24	Net Gas Plant in Service
	Parking Lot	330	24	Net Gas Plant in Service

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

	LINE ITEM		ALLOCATION FACTOR	
	Cost of Service-G.O. Complex	158,004	24	Net Gas Plant in Service
	Miscellaneous	500	24	Net Gas Plant in Service
	Other Gas Revenues			
	Sale of Sundry Junk	422	15	Distribution Plant
	Sale of Operating/Construction Material	614	15	Distribution Plant
	Patronage Dividends	3,052	31	O&M Excl. Cost of Gas
	Miscellaneous	4,504	31	O&M Excl. Cost of Gas
	Transport & Sales Penalty Revenue - Net	3,104	23	Sales & Transportation Rev.
	OPERATION & MAINTENANCE EXPENSE REPORT:			
	Cost of Purchased Gas	19,231,623		Direct to Residential Demand
		22,965,646		Direct to Residential Energy
		13,131,623		Direct to Firm General Demand
		16,355,764		Direct to Firm General Energy
		427,093		Direct to Air Force Demand
		3,043,369		Direct to Air Force Energy
		223,226		Direct to Small Int. Sales Demand
		1,463,980		Direct to Small Int. Sales Energy
		0		Direct to Large Int. Sales Demand
		0		Direct to Large Int. Sales Energy
813	Other Gas Supply Expenses	215,821	3	Dk Sales
870	Operation Supervision & Maintenance	516,162	27	All Other Dist. Operation Exp.
871	Load Dispatch	70,675	1	Dk Throughput
874	Mains & Services	878,937	22	Mains & Services
875	Measuring Stations - General	35,628	18	Meas. & Reg. Sta. Eqpt.- General
876	Measuring Stations - Industrial	37,388	21	Ind. Meas. & Reg. Sta. Eqpt.
877	Measuring Stations - City Gate	7,257	19	Meas. & Reg. Eqpt.- City Gate
878	Meters & House Regulators	585,682	16	Meters & Regulators
879	Customer Installations	760,312	10	Wtd. Customers @ Distrib. Excl. AF & LI
880	Other Gas Distribution	1,421,151	27	All Other Dist. Operation Exp.
881	Rents	20,705	27	All Other Dist. Operation Exp.
885	Maintenance Supervision & Engineering	272,457	28	All Other Dist. Maintenance Exp.
886	Structures & Improvements	2,317	17	Structures & Improvements
887	Mains	118,089	13	Distribution Mains
889	Measuring Stations - General	25,142	18	Meas. & Reg. Sta. Eqpt.- General
890	Measuring Stations - Industrial	4,594	21	Ind. Meas. & Reg. Sta. Eqpt.
891	Measuring Stations - City Gate	410	19	Meas. & Reg. Eqpt.- City Gate
892	Services	116,078	12	Weighted Customers @ Distribution
893	Meters & House Regulators	103,235	16	Meters & Regulators
894	Other Equipment	185,730	28	All Other Dist. Maintenance Exp.
901	Customer Accounts	229,995	8	Average Customers
902	Meter Reading	583,212	10	Wtd. Customers @ Distrib. Excl. AF & LI
903	Customer Records & Collection	1,519,399	8	Average Customers
904	Uncollectible Accounts	343,493	8	Average Customers
905	Miscellaneous Customer Accounts	158,847	8	Average Customers
907	Customer Service & Info.	165,359	8	Average Customers
911	Sales Expenses	470,362	8	Average Customers
920	Administration & General	4,090,058	30	O&M Excl. Gas Cost and A&G

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

	LINE ITEM		ALLOCATION FACTOR	
	DEPRECIATION EXPENSE REPORT:			
376	Mains	1,122,277	13	Distribution Mains
375	Structures	4,323	17	Structures & Improvements
378	Meas. & Reg. Sta. - General	11,908	18	Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. - City Gate	4,768	19	Meas. & Reg. Eqpt.- City Gate
380	Services	980,295	10	Wtd. Customers @ Distrib. Excl. AF & LI
381	Meters	301,513	10	Wtd. Customers @ Distrib. Excl. AF & LI
383	Service Regulators	38,945	20	Service Regulators
385	Measuring & Reg. Equip. - Indust.	7,085	21	Ind. Meas. & Reg. Sta. Eqpt.
386.1	Other Property on Cust Prem.	10,742	13	Distribution Mains
387.2	Other Equipment	39,473	13	Distribution Mains
374	Land Rights	1,152	13	Distribution Mains
	General Plant	127,855	15	Distribution Plant
	Amort. of Intangible Plant - General	2,511	15	Distribution Plant
	Common Plant	220,058	15	Distribution Plant
	Amort. of Intangible Plant - Common	185,393	15	Distribution Plant
386.3	Gas Plant Leased to Others	1,063	13	Distribution Mains
	TAXES OTHER THAN INCOME REPORT:			
	Ad Valorem Taxes			
	Distribution Plant	489,087	15	Distribution Plant
	General Plant/Intangible	52,125	15	Distribution Plant
	Common Plant/Intangible	62,617	15	Distribution Plant
	Other Taxes - Payroll, Franchise, Other	621,628	31	O&M Excl. Cost of Gas
	DEFERRED INCOME TAXES REPORT:			
	Management Incentive Compensation	(26,796)	25	Total Gas Plant in Service
	Pension Expense	296,215	25	Total Gas Plant in Service
	Sundry Reserves	2,192	25	Total Gas Plant in Service
	Reserve For Deferred Maintenance	2,235	25	Total Gas Plant in Service
	Property Insurance Adjustment	(8,384)	25	Total Gas Plant in Service
	Bad Debt Expense	13,351	23	Sales & Transportation Rev.
	Accrued Vacation	21,968	31	O&M Excl. Cost of Gas
	Capitalized Overheads	(148,861)	25	Total Gas Plant in Service
	Customer Advances Total	26,724	11	Average Res. & Firm General Cust.
	Restricted Stock Bonus Plan	22,298	31	O&M Excl. Cost of Gas
	FAS 106 -OPRB	13,504	31	O&M Excl. Cost of Gas
	Deferred Compensation - Directors	(6,837)	31	O&M Excl. Cost of Gas
	Board of Directors - Retirement Benefits	(104,470)	31	O&M Excl. Cost of Gas
	Demand Charges	7,028	2	2-Day Peak Sales
	PCB Related Income	(3,081)	25	Total Gas Plant in Service
	Asbestos Related Income	0	25	Total Gas Plant in Service
	Liberalized Deprec. & Other Prop. Timing Differ.	(36,824)	25	Total Gas Plant in Service
	Contributions in Aid of Construction	(25,346)	11	Average Res. & Firm General Cust.
	ND - Normalized Timing Differences	(56,326)	25	Total Gas Plant in Service
	Unrecovered Purchased Gas Costs	(3,998,746)	3	Dk Sales

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

LINE ITEM		ALLOCATION FACTOR	
Rate Case Expense	0	30	O&M Excl. Gas Cost and A&G
Amort. of Loss on Bond Retirements	(42,324)	24	Net Gas Plant in Service
FAS 106 Deferred Expense	(22,313)	31	O&M Excl. Cost of Gas
Gas IRP	(20,993)	3	Dk Sales
Closing/Filing and Out of Period & Fed & State FA	64,093	25	Total Gas Plant in Service
Accumulated Balance 12/31/01	(4,271,992)	25	Total Gas Plant in Service
INCOME TAXES REPORT:			
Interest Charges	1,013,654	24	Net Gas Plant in Service
Deductions			
Management Incentive Compensation	(67,648)	25	Total Gas Plant in Service
Pension Expense	747,828	25	Total Gas Plant in Service
Sundry Reserves	5,536	25	Total Gas Plant in Service
Reserve For Deferred Maintenance	5,813	25	Total Gas Plant in Service
Property Insurance Adjustment	(21,165)	25	Total Gas Plant in Service
Bad Debt Expense	33,706	23	Sales & Transportation Rev.
Accrued Vacation	55,460	31	O&M Excl. Cost of Gas
Capitalized Overheads	(375,817)	25	Total Gas Plant in Service
Customer Advances	67,468	11	Average Res. & Firm General Cust.
Restricted Stock Bonus Plan	56,295	31	O&M Excl. Cost of Gas
FAS 106 - OPRB	33,145	31	O&M Excl. Cost of Gas
Deferred Compensation - Directors	(17,259)	31	O&M Excl. Cost of Gas
Board of Directors - Retirement Benefits	(263,746)	31	O&M Excl. Cost of Gas
Demand Charges	17,742	2	2-Day Peak Sales
PCB Related Income	(4,985)	25	Total Gas Plant in Service
Asbestos Related Income	0	25	Total Gas Plant in Service
Plant Reclassification	(7,677)	25	Total Gas Plant in Service
Liberalized Depreciation & OPTD	(552,874)	25	Total Gas Plant in Service
Contributions in Aid of Construction	(42,068)	11	Average Res. & Firm General Cust.
Purchased Gas Cost Adjustment	(10,095,293)	3	Dk Sales
Rate Case Expense	0	30	O&M Excl. Gas Cost and A&G
Amort. of Loss on Bond Retirements	(106,850)	24	Net Gas Plant in Service
FAS 106 - Deferred Expense	(56,330)	31	O&M Excl. Cost of Gas
Gas IRP	(53,000)	24	Net Gas Plant in Service
Disallowed Meals & Entertainment	(25,609)	31	O&M Excl. Cost of Gas
Federal Non-Hwy. Use Tax Credit	(3,859)	25	Total Gas Plant in Service
Preferred Dividend Paid Deduction	13,572	25	Total Gas Plant in Service
State Income Tax	861,216	35	Taxable Income
Rounding & Prior Year Adjustments	(30,408)	25	Total Gas Plant in Service
Taxable Income @ Federal Tax Rate	35.00%		Direct Input
Credits & Adjustments	(54,273)	35	Taxable Income
WORKING CAPITAL REPORT:			
Materials & Supplies	381,856	15	Distribution Plant
Prepaid Insurance	21,567	25	Total Gas Plant in Service
Unamortized Gas IRP Costs - Other	123,984	3	Dk Sales
Fuel Stocks	18,683		DK Sales - Propane Dk only

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

LINE ITEM		ALLOCATION FACTOR	
INVESTMENT TAX CREDIT BALANCE REPORT:			
Investment Tax Credit Balance	(273,541)	25	Total Gas Plant in Service
RATE BASE REPORT:			
Customer Advances for Const.	(161,802)	11	Average Res. & Firm General Cust.
Direct to Firm	(10,000)		Direct to Firm Customer
Direct to Firm	(13,161)		Direct to Firm Customer
Direct to Firm	(21,545)		Direct to Firm Customer
Direct to Firm	(11,780)		Direct to Firm Customer
Direct to Small Int Transport	(49,571)		Direct to Small Int Transport Customer
ADJUSTMENTS TO PER BOOKS:			
Revenues:			
Residential	(7,024,168)		Direct to Residential Demand
	(10,718,053)		Direct to Residential Energy
	0		Direct to Residential Customer
Firm General	(4,796,201)		Direct to Firm General Demand
	(7,845,189)		Direct to Firm General Energy
	0		Direct to Firm General Customer
Air Force	(155,992)		Direct to Air Force Demand
	(2,603,334)		Direct to Air Force Energy
	0		Direct to Air Force Customer
Small Interruptible Sales	(81,531)		Direct to Small Int. Sales Demand
	(587,776)		Direct to Small Int. Sales Energy
	(1,365)		Direct to Small Int. Sales Customer
Small Interruptible Transportation	(54,353)		Direct to Small Int. Transport Energy
	(7,310)		Direct to Small Int. Transport Customer
Large Interruptible Sales	0		Direct to Large Int. Sales Demand
	(11,939)		Direct to Large Int. Sales Energy
	(900)		Direct to Large Int. Sales Customer
Large Interruptible Transportation	(206,833)		Direct to Large Int. Transport Energy
	(17,000)		Direct to Large Int. Transport Customer
Unbilled Revenues	6,333,648	26	Sales Revenue
Cost of Gas:			
	(7,024,168)		Direct to Residential Demand
	(8,387,983)		Direct to Residential Energy
	(4,796,201)		Direct to Firm General Demand
	(5,973,788)		Direct to Firm General Energy
	(155,992)		Direct to Air Force Demand
	(1,111,562)		Direct to Air Force Energy
	(81,531)		Direct to Small Int. Sales Demand
	(534,705)		Direct to Small Int. Sales Energy
	0		Direct to Large Int. Sales Demand
	0		Direct to Large Int. Sales Energy

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

LINE ITEM	ALLOCATION FACTOR	
COST OF SERVICE BY COMPONENT REPORT:		
Operating Income for Proposed Return	11.044%	
Related Taxes for Increase		
Inverse Tax Rate for Federal & State Income	60.390%	
Billing Units @ Customer		
Dk Throughput	7,681,994	Direct to Residential Energy
	5,470,992	Direct to Firm General Energy
	1,018,005	Direct to Air Force Energy
	489,700	Direct to Small Int. Sales Energy
	1,030,440	Direct to Small Int. Transport Energy
	0	Direct to Large Int. Sales Energy
	2,246,820	Direct to Large Int. Transport Energy
Bills	859,416	Direct to Residential Customer
	132,276	Direct to Firm General Customer
	36	Direct to Air Force Customer
	888	Direct to Small Int. Sales Customer
	864	Direct to Small Int. Transport Customer
	0	Direct to Large Int. Sales Customer
	108	Direct to Large Int. Transport Customer
Peak Day Dk Demand	114,254	Direct to Residential Demand
	78,014	Direct to Firm General Demand
	2,537	Direct to Air Force Demand
	1,300	Direct to Small Int. Sales Demand
	2,515	Direct to Small Int. Transport Demand
	0	Direct to Large Int. Sales Demand
	2,103	Direct to Large Int. Transport Demand

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERV ICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

		Total	Residential			Firm General			Air Force		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput	17,937,951		7,681,994			5,470,992			1,018,005	
		100.000001%	0.000000%	42.825371%	0.000000%	0.000000%	30.499537%	0.000000%	0.000000%	5.675147%	0.000000%
2.	2-Day Peak Sales	209,412	115,109			78,762			5,220		
		100.000000%	54.967719%	0.000000%	0.000000%	37.611025%	0.000000%	0.000000%	2.492694%	0.000000%	0.000000%
3.	Dk Sales	14,660,691		7,681,994			5,470,992			1,018,005	
		100.000000%	0.000000%	52.398581%	0.000000%	0.000000%	37.317422%	0.000000%	0.000000%	6.943772%	0.000000%
4.	Dk Throughput @ Distribution	15,194,988		7,541,319			5,347,943			145,706	
		100.000000%	0.000000%	49.630306%	0.000000%	0.000000%	35.195441%	0.000000%	0.000000%	0.958908%	0.000000%
5.	2-Day Peak @ Distribution	200,723	114,254			78,014			2,537		
		100.000002%	56.921230%	0.000000%	0.000000%	38.866498%	0.000000%	0.000000%	1.263931%	0.000000%	0.000000%
8.	Average Customers	82,799			71,618			11,023			3
		100.000001%	0.000000%	0.000000%	86.496214%	0.000000%	0.000000%	13.312963%	0.000000%	0.000000%	0.003623%
9.	Average Customers @ Distribution	81,502			70,495			10,858			2
		99.999999%	0.000000%	0.000000%	86.494810%	0.000000%	0.000000%	13.322372%	0.000000%	0.000000%	0.002454%
10.	Wtd. Customers @ Distrib. Excl. AF & LI	127,464			70,495			54,290			
		100.000000%	0.000000%	0.000000%	55.305812%	0.000000%	0.000000%	42.592418%	0.000000%	0.000000%	0.000000%
11.	Average Res. & Firm General Cust.	82,641			71,618			11,023			
		100.000000%	0.000000%	0.000000%	86.661584%	0.000000%	0.000000%	13.338416%	0.000000%	0.000000%	0.000000%
12.	Weighted Customers @ Distribution	127,464			70,495			54,290			0
		100.000000%	0.000000%	0.000000%	55.305812%	0.000000%	0.000000%	42.592418%	0.000000%	0.000000%	0.000000%
13	Distribution Mains	27,079,883	9,865,090	0	8,432,170	6,736,001	0	1,298,766	219,053	0	239
		100.000000%	36.429589%	0.000000%	31.138133%	24.874557%	0.000000%	4.796055%	0.808914%	0.000000%	0.000883%
15.	Distribution Plant	55,450,251	10,678,474	0	23,359,827	7,291,390	0	12,428,910	237,113	0	112,088
		100.000001%	19.257756%	0.000000%	42.127541%	13.149427%	0.000000%	22.414524%	0.427614%	0.000000%	0.202142%
16.	Meters & Regulators	13,660,556	0	0	7,526,766	0	0	5,821,704	0	0	0
		100.000000%	0.000000%	0.000000%	55.098533%	0.000000%	0.000000%	42.616889%	0.000000%	0.000000%	0.000000%

CASE NO. _____
STATEMENT M
PART C
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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERV ICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

		Small Interruptible Sales			Small Interruptible Transport			Large Interruptible Sales			Large Interruptible Transport		
		Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput		489,700			1,030,440			0			2,246,820	
		0.000000%	2.729966%	0.000000%	0.000000%	5.744469%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	12.525511%	0.000000%
2.	2-Day Peak Sales	1,342			2,823			0			6,156		
		0.640842%	0.000000%	0.000000%	1.348060%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	2.939660%	0.000000%	0.000000%
3.	Dk Sales		489,700					-	0				
		0.000000%	3.340225%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
4.	Dk Throughput @ Distribution		474,400			918,000			0			767,620	
		0.000000%	3.122082%	0.000000%	0.000000%	6.041466%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	5.051797%	0.000000%
5.	2-Day Peak @ Distribution	1,300			2,515			0			2,103		
		0.647659%	0.000000%	0.000000%	1.252971%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	1.047713%	0.000000%	0.000000%
8.	Average Customers			74			72			0			9
		0.000000%	0.000000%	0.089373%	0.000000%	0.000000%	0.086958%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.010870%
9.	Average Customers @ Distribution			72			69			0			6
		0.000000%	0.000000%	0.088341%	0.000000%	0.000000%	0.084660%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.007362%
10.	Wtd. Customers @ Distrib. Excl. AF & LI			1,368			1,311						
		0.000000%	0.000000%	1.073244%	0.000000%	0.000000%	1.028526%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11.	Average Res. & Firm General Cust.												
		0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12.	Weighted Customers @ Distribution			1,368			1,311			0			0
		0.000000%	0.000000%	1.073244%	0.000000%	0.000000%	1.028526%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Distribution Mains	112,247	0	8,612	217,154	0	8,253	0	0	0	181,580	0	718
		0.414503%	0.000000%	0.031802%	0.801902%	0.000000%	0.030476%	0.000000%	0.000000%	0.000000%	0.670535%	0.000000%	0.002651%
15.	Distribution Plant	121,502	0	296,406	235,058	0	304,336	0	0	0	196,551	0	188,596
		0.219119%	0.000000%	0.534544%	0.423908%	0.000000%	0.548845%	0.000000%	0.000000%	0.000000%	0.354464%	0.000000%	0.340117%
16.	Meters & Regulators	0	0	152,635	0	0	155,855	0	0	0	0	0	3,596
		0.000000%	0.000000%	1.117341%	0.000000%	0.000000%	1.140913%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.026324%

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERV ICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

		Total	Residential			Firm General			Air Force		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
17.	Structures & Improvements	180,117	46,730	0	39,942	31,908	0	10,370	1,038	0	13,407
		100.000000%	25.944247%	0.000000%	22.175586%	17.715152%	0.000000%	5.757369%	0.576292%	0.000000%	7.443495%
18.	Meas. & Reg. Sta. Eqpt.- General	520,093	187,902	0	160,609	128,302	0	24,738	4,172	0	4,302
		100.000000%	36.128539%	0.000000%	30.880823%	24.669050%	0.000000%	4.756457%	0.802164%	0.000000%	0.827160%
19.	Meas. & Reg. Eqpt.- City Gate	174,001	57,348	0	49,018	39,158	0	14,437	1,273	0	1
		99.999999%	32.958431%	0.000000%	28.171102%	22.504468%	0.000000%	8.297079%	0.731605%	0.000000%	0.000575%
20.	Service Regulators	1,677,415	0	0	899,393	0	0	717,794	0	0	0
		100.000000%	0.000000%	0.000000%	53.617799%	0.000000%	0.000000%	42.791676%	0.000000%	0.000000%	0.000000%
21.	Ind. Meas. & Reg. Sta. Eqpt.	371,029	33,286	0	28,451	22,728	0	30,438	739	0	94,127
		100.000000%	8.971266%	0.000000%	7.668134%	6.125667%	0.000000%	8.203671%	0.199176%	0.000000%	25.369176%
22.	Mains & Services	39,204,561	9,865,090	0	15,137,822	6,736,001	0	6,462,960	219,053	0	239
		100.000000%	25.163118%	0.000000%	38.612400%	17.181677%	0.000000%	16.485225%	0.558744%	0.000000%	0.000610%
23.	Sales & Transportation Rev.	95,126,405	18,016,893	29,032,671	5,370,088	12,302,188	20,940,614	1,393,298	400,116	4,520,837	9,218
		100.000000%	18.939949%	30.520097%	5.645213%	12.932464%	22.013461%	1.464681%	0.420615%	4.752452%	0.009690%
24.	Net Gas Plant in Service	23,428,222	4,148,662	0	10,049,721	2,832,758	0	5,600,021	92,120	0	76,522
		100.000000%	17.707968%	0.000000%	42.895790%	12.091221%	0.000000%	23.902885%	0.393201%	0.000000%	0.326623%
25.	Total Gas Plant in Service	69,322,208	13,351,854	0	29,202,492	9,116,807	0	15,536,239	296,475	0	140,107
		100.000000%	19.260572%	0.000000%	42.125738%	13.151351%	0.000000%	22.411633%	0.427677%	0.000000%	0.202110%
26.	Sales Revenue	100,274,418	19,231,623	30,990,104	5,732,149	13,131,623	22,352,466	1,487,237	427,093	4,825,640	9,840
		100.000000%	19.178992%	30.905294%	5.716462%	13.095686%	22.291295%	1.483167%	0.425924%	4.812434%	0.009813%
27.	All Other Dist. Operation Exp.	2,305,200	239,786	0	1,098,491	163,728	0	723,693	5,324	0	9,785
		100.000001%	10.401961%	0.000000%	47.652742%	7.102551%	0.000000%	31.393935%	0.230956%	0.000000%	0.424475%
28.	All Other Dist. Maintenance Exp.	367,547	52,649	0	166,082	35,949	0	100,707	1,169	0	1,374
		100.000001%	14.324427%	0.000000%	45.186602%	9.780790%	0.000000%	27.399761%	0.318055%	0.000000%	0.373830%
30.	O&M Excl. Gas Cost and A&G	8,632,608	562,342	30,267	5,225,264	383,971	21,556	2,197,584	12,486	4,011	21,459
		100.000000%	6.514161%	0.350612%	60.529379%	4.447914%	0.249704%	25.456780%	0.144638%	0.046463%	0.248581%

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERV ICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

		Small Interruptible Sales			Small Interruptible Transport			Large Interruptible Sales			Large Interruptible Transport		
		Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
17.	Structures & Improvements	532	0	41	1,029	0	39	0	0	0	860	0	34,221
		0.295364%	0.000000%	0.022763%	0.571295%	0.000000%	0.021653%	0.000000%	0.000000%	0.000000%	0.477467%	0.000000%	18.999317%
18.	Meas. & Reg. Sta. Eqpt.- General	2,138	0	164	4,136	0	157	0	0	0	3,459	0	14
		0.411080%	0.000000%	0.031533%	0.795242%	0.000000%	0.030187%	0.000000%	0.000000%	0.000000%	0.665073%	0.000000%	0.002692%
19.	Meas. & Reg. Eqpt.- City Gate	653	0	50	1,262	0	9,741	0	0	0	1,056	0	4
		0.375285%	0.000000%	0.028735%	0.725283%	0.000000%	5.598244%	0.000000%	0.000000%	0.000000%	0.606893%	0.000000%	0.002299%
20.	Service Regulators	0	0	24,027	0	0	32,605	0	0	0	0	0	3,596
		0.000000%	0.000000%	1.432383%	0.000000%	0.000000%	1.943765%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.214377%
21.	Ind. Meas. & Reg. Sta. Eqpt.	379	0	4,351	733	0	5,177	0	0	0	613	0	150,007
		0.102148%	0.000000%	1.172685%	0.197559%	0.000000%	1.395309%	0.000000%	0.000000%	0.000000%	0.165216%	0.000000%	40.429993%
22.	Mains & Services	112,247	0	138,739	217,154	0	132,958	0	0	0	181,580	0	718
		0.286311%	0.000000%	0.353885%	0.553900%	0.000000%	0.339139%	0.000000%	0.000000%	0.000000%	0.463160%	0.000000%	0.001831%
23.	Sales & Transportation Rev.	209,126	1,704,474	29,215	0	538,661	80,410	0	11,185	843	0	495,568	71,000
		0.219840%	1.791799%	0.030712%	0.000000%	0.566258%	0.084530%	0.000000%	0.011758%	0.000886%	0.000000%	0.520957%	0.074638%
24.	Net Gas Plant in Service	47,203	0	137,745	91,320	0	148,045	0	0	0	76,361	0	127,744
		0.201479%	0.000000%	0.587945%	0.389786%	0.000000%	0.631909%	0.000000%	0.000000%	0.000000%	0.325936%	0.000000%	0.545257%
25.	Total Gas Plant in Service	151,920	0	370,502	293,905	0	380,411	0	0	0	245,758	0	235,738
		0.219151%	0.000000%	0.534464%	0.423969%	0.000000%	0.548758%	0.000000%	0.000000%	0.000000%	0.354516%	0.000000%	0.340061%
26.	Sales Revenue	223,226	1,819,393	31,185	0	0	0	0	11,939	900	0	0	0
		0.222615%	1.814414%	0.031100%	0.000000%	0.000000%	0.000000%	0.000000%	0.011906%	0.000898%	0.000000%	0.000000%	0.000000%
27.	All Other Dist. Operation Exp.	2,727	0	18,265	5,278	0	18,422	0	0	0	4,414	0	15,287
		0.118298%	0.000000%	0.792339%	0.228961%	0.000000%	0.799150%	0.000000%	0.000000%	0.000000%	0.191480%	0.000000%	0.663153%
28.	All Other Dist. Maintenance Exp.	599	0	2,499	1,159	0	2,503	0	0	0	969	0	1,888
		0.162972%	0.000000%	0.679913%	0.315334%	0.000000%	0.681001%	0.000000%	0.000000%	0.000000%	0.263640%	0.000000%	0.513676%
30.	O&M Excl. Gas Cost and A&G	6,396	1,929	48,234	12,378	4,060	48,202	0	0	0	10,351	8,852	33,266
		0.074091%	0.022346%	0.558742%	0.143387%	0.047031%	0.558371%	0.000000%	0.000000%	0.000000%	0.119906%	0.102541%	0.385353%

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERV ICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

		Total	Residential			Firm General			Air Force		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
31.	O&M Excl. Cost of Gas	12,722,666	828,775	44,607	7,700,951	565,893	31,769	3,238,781	18,402	5,911	31,626
		99.999998%	6.514161%	0.350610%	60.529381%	4.447912%	0.249704%	25.456779%	0.144639%	0.046460%	0.248580%
33.	Total Cost of Gas	77,058,145	19,231,623	23,078,733	0	13,131,623	16,436,303	0	427,093	3,058,355	0
		100.000001%	24.957288%	29.949765%	0.000000%	17.041188%	21.329741%	0.000000%	0.554248%	3.968893%	0.000000%
35.	Taxable Income	10,992,109	(2,795,765)	11,188,395	(4,304,089)	(1,908,990)	8,232,120	(2,908,127)	(62,309)	2,155,927	(29,355)
		100.000000%	-25.434291%	101.785699%	-39.156171%	-17.366913%	74.891179%	-26.456497%	-0.566852%	19.613406%	-0.267055%
38.	Customer Account Expense O&M	229,995	0	0	198,937	0	0	30,619	0	0	8
		99.999999%	0.000000%	0.000000%	86.496228%	0.000000%	0.000000%	13.312898%	0.000000%	0.000000%	0.003478%
39.	Distribution O&M	5,161,944	562,342	30,267	2,405,175	383,971	21,556	1,564,775	12,486	4,011	21,355
		100.000001%	10.893997%	0.586349%	46.594364%	7.438496%	0.417595%	30.313676%	0.241886%	0.077703%	0.413701%

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERV ICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

		Small Interruptible Sales			Small Interruptible Transport			Large Interruptible Sales			Large Interruptible Transport		
		Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
31.	O&M Excl. Cost of Gas	9,426	2,843	71,087	18,243	5,984	71,040	0	0	0	15,255	13,046	49,027
		0.074088%	0.022346%	0.558743%	0.143390%	0.047034%	0.558374%	0.000000%	0.000000%	0.000000%	0.119904%	0.102541%	0.385352%
33.	Total Cost of Gas	223,226	1,471,189	0	0	0	0	0	0	0	0	0	0
		0.289685%	1.909193%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
35.	Taxable Income	(32,093)	567,013	(67,092)	(34,702)	532,317	(16,150)	0	11,181	843	(29,337)	481,956	10,366
		-0.291964%	5.158364%	-0.610365%	-0.315699%	4.842719%	-0.146924%	0.000000%	0.101718%	0.007669%	-0.266891%	4.384564%	0.094304%
38.	Customer Account Expense O&M	0	0	206	0	0	200	0	0	0	0	0	25
		0.000000%	0.000000%	0.089567%	0.000000%	0.000000%	0.086958%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.010870%
39.	Distribution O&M	6,396	1,929	39,394	12,378	4,060	39,693	0	0	0	10,351	8,852	32,953
		0.123907%	0.037370%	0.763162%	0.239793%	0.078653%	0.768954%	0.000000%	0.000000%	0.000000%	0.200525%	0.171486%	0.638384%

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MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002	2003
Operating Revenues			
Sales	$93,961	$67,944	$67,962
Transportation	1,165	900	900
Other	287	287	287
Total Revenues	95,413	69,131	69,149
Operating Expenses			
Operation and Maintenance			
Cost of Gas	76,842	50,116	50,072
Other O&M	12,938	13,829	14,354
Total O&M	89,780	63,945	64,426
Depreciation	3,059	3,143	3,261
Taxes Other Than Income	1,226	1,313	1,352
Current Income Taxes	4,322	(3,067)	(1,961)
Deferred Income Taxes	(4,031)	2,961	1,612
Total Expenses	94,356	68,295	68,690
Operating Income	$1,057	$836	$459
Average Rate Base	$19,954	$19,449	$19,681
Rate of Return	5.297%	4.298%	2.332%

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

	Projected 2002		Projected 2003	
	Dk	Revenue	Dk	Revenue
Sales				
Residential	7,895	$39,117	7,900	$39,198
Firm General	5,627	24,843	5,609	24,780
Air Force				
Firm	36	133	36	133
Interuptible	1,015	2,448	1,015	2,448
Total Air Force	1,051	2,581	1,051	2,581
Small Interruptible	490	1,403	490	1,403
Large Interruptible	0	0	0	0
Total Sales	15,063	$67,944	15,050	$67,962
Transportation				
Small Interruptible	1,030	$557	1,030	$557
Large Interruptible	2,247	343	2,247	343
Total Transportation	3,277	$900	3,277	$900
Total Throughput	18,340	$68,844	18,327	$68,862

MONTANA-DAKOTA UTILITIES CO.
MISCELLANEOUS REVENUES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002	2003
Miscellaneous Service Revenue	$77	$77	$77
Rent from Property	198	198	198
Other Revenue	12	12	12
Total Misc. Revenues	$287	$287	$287

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002
(000S)

Function	Total	Cost of Gas	Labor	Benefits	Insurance	Advertising	Rate Case Expense	Energy Share	All Other O&M
Cost of Gas	$50,116	$50,116							$0
Other Gas Supply	222		$146						76
Distribution	5,322		4,375						947
Customer Accounts	2,921		1,912						1,009
Customer Service & Information	179		104			$60			15
Sales	429		346			0			83
Administrative and General	4,756		1,356	$1,298	$297	76	$56	$11	1,662
Total Other O&M	13,829	0	8,239	1,298	297	136	56	11	3,792
Total O&M	$63,945	$50,116	$8,239	$1,298	$297	$136	$56	$11	$3,792

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MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003
(000S)

Function	Total	Cost of Gas	Labor	Benefits	Insurance	Advertising	Rate Case Expense	Energy Share	All Other O&M
Cost of Gas	$50,072	$50,072							$0
Other Gas Supply	228		$150						78
Distribution	5,480		4,506						974
Customer Accounts	3,006		1,969						1,037
Customer Service & Information	182		107			$60			15
Sales	441		356			0			85
Administrative and General	5,017		1,397	1,462	306	76	$56	$11	1,709
Total Other O&M	14,354	0	8,485	1,462	306	136	56	11	3,898
Total O&M	$64,426	$50,072	$8,485	$1,462	$306	$136	$56	$11	$3,898

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MONTANA-DAKOTA UTILITIES CO.
PROJECTED COST OF GAS
GAS UTILITY - NORTH DAKOTA
(000s)

	Projected 2002			
	Dk Sales	Dk Adjusted for Distribution Losses 1/	Commodity Charge 2/	Cost of Gas
Residential	7,895	7,931	$3.428	$27,187
Firm General Service	5,627	5,652	3.428	19,375
Air Force				
Firm	36	36	3.428	123
Interruptible	1,015	1,015	2.277	2,311
Total Air Force	1,051	1,051		2,434
Small Interruptible	490	492	2.277	1,120
Large Interruptible	0	0	2.277	0
Total	15,063	15,126		$50,116

	Projected 2003			
	Dk Sales	Dk Adjusted for Distribution Losses 1/	Commodity Charge 2/	Cost of Gas
Residential	7,900	7,936	$3.428	$27,205
Firm General Service	5,609	5,634	3.428	19,313
Air Force				
Firm	36	36	3.428	123
Interruptible Contract	1,015	1,015	2.277	2,311
Total Air Force	1,051	1,051		2,434
Small Interruptible	490	492	2.277	1,120
Large Interruptible	0	0	2.277	0
Total	15,050	15,113		$50,072

1/ Distribution loss factor of .45%.
2/ Exhibit B, Purchased Gas Cost Adjustment effective March 1, 2002.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
LABOR EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002 1/	2003 2/
Gas Supply	$142	$146	$150
Distribution	4,241	4,375	4,506
Customer Acct.	1,854	1,912	1,969
Customer Service & Info	101	104	107
Sales	335	346	356
A&G	1,315	1,356	1,397
Total	$7,988	$8,239	$8,485

1/ Reflects average 3.15% increase reflecting average 2000-2002 bonus.
2/ Reflects projected 3.0% increase effective January 1, 2003.

MONTANA-DAKOTA UTILITIES CO.
BENEFITS EXPENSE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

	2001	2002	2003
Medical/Dental	$823	$814	$879
Pension expense	(649)	(575)	(475)
Post-retirement	468	541	527
401-K	200	211	217
Workers compensation	22	48	49
SISP	0	259	265
Total	$864	$1,298	$1,462

MONTANA-DAKOTA UTILITIES CO.
INSURANCE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002	2003
Insurance Expense	$212	$297	$306

MONTANA-DAKOTA UTILITIES CO.
RATE CASE EXPENSE
PROJECTED 2002-2003
(000s)

	2001	2002 1/	2003 1/
Rate Case Expense	$1	$56	$56

1/ Reflects three year amortization of rate case expense.

MONTANA-DAKOTA UTILITIES CO.
ADVERTISING EXPENSE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002	2003
Informational	$49	$60	$60
Promotional	54		
Institutional	81	76	76
Total	$184	$136	$136

MONTANA-DAKOTA UTILITIES CO.
CHARITABLE CONTRIBUTIONS
2001 AND PROJECTED 2002-2003
(000s)

Charitable Contributions	Total
Energy Share of ND	$20
Allocate to Gas 1/	$11

1/ Allocated on customers.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO OTHER O&M FOR INFLATION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000S)

Function	2001 Other O&M	2002 Projected 1/	2003 Projected 1/
Other Gas Supply	$74	$76	$78
Distribution	921	947	974
Customer Accounts	981	1,009	1,037
Customer Service & Informati	15	15	15
Sales	81	83	85
Administrative and General	1,617	1,662	1,709
Total Other O&M	$3,689	$3,792	$3,898

1/ Increase of 2.81%.

MONTANA-DAKOTA UTILITIES CO.
ITEMS ADJUSTED INDIVIDUALLY
GAS UTILITY - NORTH DAKOTA
(000s)

Function	Per Books	Cost of Gas	Labor	Benefits	Insurance	Rate Case Expense	Advertising	All Other O&M
Cost of Gas	$76,842	(76,842)						$0
Other Gas Supply	216		($142)					74
Distribution	5,162		(4,241)					921
Customer Accounts	2,835		(1,854)					981
Customer Service & Information	165		(101)				($49)	15
Sales	470		(335)				(54)	81
Administrative and General	4,090		(1,315)	(864)	(212)	(1)	(81)	1,617
Total Other O&M	12,938	0	(7,988)	(864)	(212)	(1)	(184)	3,689
Total O&M	$89,780	($76,842)	($7,988)	($864)	($212)	($1)	($184)	$3,689

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
DEPRECIATION EXPENSE
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002	2003
Distribution	$2,523	$2,608	2,703
General	128	112	104
Intangible Plant - General	3	5	5
Common	220	214	217
Intangible Plant - Common	185	201	229
Acquisition Adjustment		3	3
Total	$3,059	$3,143	$3,261

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

		Projected	
Type of Tax	2001	2002	2003
Ad Valorem			
Distribution	$489	$503	$522
General	52	52	51
Common	60	59	60
Intangible	3	3	3
Total Ad Valorem Taxes	$604	$617	$636
O&M Related Taxes - Other			
FICA	580	662	682
Federal & State Employment	8		
Franchise	13	13	13
Delaware Franchise	21	21	21
Total O&M Related Taxes	622	696	$716
Total Taxes Other Than Income	$1,226	$1,313	$1,352

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

Function	Effective Tax Rate	Projected 2002 Plant Balance	Projected 2002 Ad Valorem Tax	Projected 2003 Plant Balance	Projected 2003 Ad Valorem Tax
Distribution 1/	0.8973%	$56,084	$503	$58,135	$522
General	0.7586%	6,815	52	6,692	51
General Intangible	0.1470%	207	0	207	0
Common	1.1153%	5,278	59	5,421	60
Common Intangible	0.1470%	1,965	3	2,241	3
Total Ad Valorem Taxes		$70,349	$617	$72,696	$636

1/ Includes gas plant leased to others.

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Function	Average Plant Balance @ 12/31/01	Ad Valorem Tax @ 12/31/01	Effective Tax Rate
Distribution 1/	$54,506,506	$489,087	0.8973%
General	6,831,889	51,828	0.7586%
Common	5,381,300	60,018	1.1153%
Intangible 2/	1,970,485	2,896	0.1470%
Total	$68,690,180	$603,829	

1/ Includes gas plant leased to others.
2/ General and common intangible.

MONTANA-DAKOTA UTILITIES CO.
PAYROLL TAXES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002 1/	2003 1/
FICA	$580		
Federal & State Unemployment	8		
Total	$588	$662	$682

1/ Caculated based on 2001 ratio of payroll taxes to labor.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
CALCULATION OF CURRENT INCOME TAXES
PROJECTED 2002-2003
(000s)

	Projected	
	2002	2003
Operating Revenues		
Sales Revenues	$67,944	$67,962
Transportation Revenues	900	900
Other Revenues	287	287
Total Operating Revenues	69,131	69,149
Operating Expenses		
Operation and Maintenance		
Cost of Gas	50,116	50,072
Other O&M	13,829	14,354
Total O&M	63,945	64,426
Depreciation Expense	3,143	3,261
Taxes other Than Income	1,313	1,352
Total Operating Expenses	68,401	69,039
Gross Adjustments to Operating Income	730	110
Deductions and Adjustments to Book Income:		
Interest Expense	784	778
Preferred Dividend Paid	15	15
Other Tax Deductions	7,675	4,267
Total Adjustments to Taxable Income	8,474	5,060
Taxable Income	(7,744)	(4,950)
Federal & State Income Taxes @ 39.61%	($3,067)	($1,961)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
INTEREST EXPENSE ANNUALIZATION
PROJECTED 2002-2003
(000s)

	Projected	
	2002	2003
Rate Base	$19,449	$19,681
Long Term Debt Ratio	43.61%	43.04%
Long Term Debt Cost	9.241%	9.180%
Weighted Cost of Debt	4.030%	3.951%
Interest Expense	$784	$778

MONTANA-DAKOTA UTILITIES CO.
INCOME TAX DEDUCTIONS
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

	Projected	
	2002	2003
1900 Account M-1's		
Management Incentive Compensation		
Pension Expense	487	403
Sundry Reserves		
Reserve for Deferred Maintenance		
Property Insurance Adjustment		
Bad Debt Expense		
Accrued Vacation		
Capitalized Overheads		
Customer Advances		
Restricted Stock Bonus Plan		
FAS 106 - OPRB		
Deferred Compensation		
BOD Retirement	(167)	(167)
Demand Charges		
PCB Related Income		
Plant Reclassification		
2820 Account M-1's		
Liberalized Depreciation and Other Property Timing Differences	(691)	(563)
Contributions in Aid of Construction		
2830 Account M-1's		
Purchased Gas Cost Adjustment	8,271	4,758
Amortization of Loss on Bond Retirements	(145)	(135)
FAS 106 - Deferred Expense	(51)	
Gas IRP		
Permanent M-1's		
Meals & Entertainment	(29)	(29)
Federal Nonhwy Use Tax Credit		
Total M-1 Deductions	$7,675	$4,267

MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAXES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

	Projected	
	2002	2003
Gas Utility - Rate Base Deductions:		
Depreciation, Retirements and Other Timing Differences Required to be Normalized	($365)	($314)
Contributions In Aid of Construction		
Customer Advances		
Total Rate Base Deductions	(365)	(314)
Gas Utility - Current Timing Differences:		
Management Incentive Compensation		
Pension Expense	193	160
Sundry Reserves		
Reserve for Deferred Maintenance		
Property Insurance Adjustment		
Bad Debt Expense		
Accrued Vacation		
Capitalized Overheads		
Restricted Stock Bonus Plan		
FAS 106	(20)	
Deferred Compensation		
BOD Retirement	(66)	(66)
Demand Charges		
PCB Related Income		
Unrecovered Purchased Gas Cost	3,276	1,885
Amort of Loss on Bond Retirements	(57)	(53)
Gas IRP		
Closing/Filing Adj.		
Total Current Timing Differences	3,326	1,926
Total	$2,961	$1,612

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002	2003
Gas Plant in Service	$68,787	$70,446	$72,793
Accumulated Reserve for Depreciation	44,629	47,021	49,356
Net Gas Plant in Service	24,158	23,425	23,437
CWIP in Service Pending Reclassification	167		
Total Gas Plant in Service	24,325	23,425	23,437
Additions			
Materials and Supplies	402	439	439
Fuel Stock	21	22	22
Prepayments	19	84	84
Other	151	97	44
Total Additions	593	642	589
Total Before Deductions	$24,918	$24,067	$24,026
Deductions			
Accumulated Deferred Income Taxes	$4,297	$4,090	$3,842
Accumulated Investment Tax Credits	290	256	231
Customer Advances	377	272	272
Total Deductions	4,964	4,618	4,345
Total Rate Base	$19,954	$19,449	$19,681

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

	2001 1/	Projected 2002	Average 2002	Projected 2003	Average 2003
Distribution	$55,211	$56,956	$56,084	$59,314	$58,135
General	7,154	6,891	7,022	6,908	6,899
Common	7,025	7,460	7,243	7,863	7,662
Acquisition Adjustment	97	97	97	97	97
Total	$69,487	$71,404	$70,446	$74,182	$72,793

1/ Includes CWIP in Service.

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

		2002			Average	2003			Average
	2001 1/	Additions	Retirements	Balance	2002	Additions	Retirements	Balance	2003
Distribution 2/	$55,211	$1,938	($193)	$56,956	$56,084	$2,557	($199)	$59,314	$58,135
General - Other	3,294	103	(325)	3,072	3,183	60	(303)	2,829	2,950
General - Clearing Accounts	3,653	320	(361)	3,612	3,632	617	(357)	3,872	3,742
General Intangible	207	0	0	207	207	0	0	207	207
Total General	7,154	423	(686)	6,891	7,022	677	(660)	6,908	6,899
Common - Other	4,410	317	(246)	4,481	4,446	310	(250)	4,541	4,511
Common - Clearing Accounts	788	131	(44)	875	832	118	(49)	944	910
Common - Intangible	1,827	287	(10)	2,104	1,965	285	(11)	2,378	2,241
Total Common	7,025	735	(300)	7,460	7,243	713	(310)	7,863	7,662
Acquisition Adjustment	97			97	97			97	97
Total Gas Plant in Service	$69,487	$3,096	($1,179)	$71,404	$70,446	$3,947	($1,169)	$74,182	$72,793

1/ Includes CWIP in Service by function.
2/ Includes gas plant leased to others.

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MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002- 2003
(000s)

	2001	Projected 2002	Average 2002	Projected 2003	Average 2003
Distribution	$38,962	$41,371	$40,166	$43,863	$42,617
General	3,696	3,351	3,523	3,072	3,212
Common	3,236	3,399	3,318	3,598	3,499
Acquisition Adjustment	0	27	14	30	28
Total	$45,894	$48,148	$47,021	$50,563	$49,356

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002
(000s)

	2001 Acc. Reserve for Depr.	Average Plant In Service	Depreciation/ Amortization Rate 1/	2002 Depreciation/ Amortization Expense	2002 Retirements/ Removal	2002 Ending Balance	2002 Average Balance
Distribution 2/	$38,962	$56,084	4.65%	$2,608	($199)	$41,371	$40,166
General							
Other	1,668	3,183	3.53%	112	(322)	1,458	1,563
Clearing Accounts	1,830	3,632	5.87%	213	(353)	1,690	1,760
Intangible	198	207	2.19%	5	0	203	200
Total General	3,696	7,022		330	(675)	3,351	3,523
Common							
Other	2,298	4,446	4.82%	214	(267)	2,245	2,272
Clearing Accounts	294	832	7.23%	60	(34)	320	307
Intangible	644	1,965	10.21%	201	(11)	834	739
Total Common	3,236	7,243		475	(312)	3,399	3,318
Acquisition Adjustment	0	97	3/	27	0	27	14
Total Gas Plant in Service	$45,894	$70,446		$3,440	($1,186)	$48,148	$47,021
Depreciation Expense				$3,143			

1/ Composite depreciation rates by function.
2/ Includes gas plant leased to others.
3/ Amortized over 34.5 years.

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MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003
(000s)

				2003			
	2002 Acc. Reserve for Depr.	Average Plant In Service	Depreciation/ Amortization Rate 1/	Depreciation/ Amortization Expense	Retirements/ Removal	Ending Balance	2003 Average Balance
Distribution 2/	$41,371	$58,135	4.65%	$2,703	($211)	$43,863	$42,617
General							
Other	1,458	2,950	3.53%	104	(282)	1,280	1,369
Clearing Accounts	1,690	3,742	5.87%	220	(326)	1,584	1,637
Intangible	203	207	2.19%	5	0	208	206
Total General	3,351	6,899		329	(608)	3,072	3,212
Common							
Other	2,245	4,511	4.82%	217	(261)	2,201	2,223
Clearing Accounts	320	910	7.23%	66	(37)	349	335
Intangible	834	2,241	10.21%	229	(15)	1,048	941
Total Common	3,399	7,662		512	(313)	3,598	3,499
Acquisition Adjustment	27	97	3/	3	0	30	28
Total Gas Plant in Service	$48,148	$72,793		$3,547	($1,132)	$50,563	$49,356
Depreciation Expense				$3,261			

1/ Composite depreciation rates by function.
2/ Includes gas plant leased to others.
3/ Amortized over 34.5 years.

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MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF WORKING CAPITAL AND
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

	Average	
Working Capital	2002	2003
Materials and Supplies	$439	$439
Fuel Stocks	$22	$22
Prepayments	84	84
Gas IRP	97	44
Total Working Capital	$642	$589
Customer Advances for Construction	$272	$272

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

	2001	2002	2003
December 2000	$421		
January 2001	401		
February	400		
March	412		
April	447		
May	456		
June	494		
July	469		
August	486		
September	467		
October	449		
November	418		
December	382		
13 Month average	$439	$439	$439

MONTANA-DAKOTA UTILITIES CO.
FUEL STOCKS
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000S)

	2001	2002	2003
December 2000	$23		
January 2001	26		
February	23		
March	22		
April	21		
May	13		
June	16		
July	11		
August	26		
September	29		
October	29		
November	23		
December	19		
13 Month Average	$22	$22	$22

MONTANA-DAKOTA UTILITIES CO.
PREPAYMENTS
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

	2001	2002	2003
December	$17	$22	$2
January	2	174	178
February	7	156	160
March	8	144	148
April	(6)	130	133
May	26	112	115
June	87	100	102
July	75	82	83
August	75	64	65
September	63	46	47
October	48	28	28
November	36	29	29
December	22	2	2
13 Month Average	$35	$84	$84

MONTANA-DAKOTA UTILITIES CO.
GAS INTEGRATED RESOURCE PLAN
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

	2001	2002	2003
December 2000	$177	$124	$71
January 2001	173	120	67
February	168	115	62
March	164	111	58
April	159	106	53
May	155	102	49
June	150	97	44
July	146	93	40
August	142	89	36
September	137	84	31
October	133	80	27
November	128	75	22
December	124	71	18
13 month Average Balance	$150	$97	$44

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

	2001	2002	2003
December 2000	$486	$268	$268
January 2001	482	268	268
February	477	268	268
March	484	268	268
April	435	268	268
May	432	268	268
June	433	268	268
July	280	280	280
August	281	281	281
September	281	281	281
October	279	279	279
November	267	267	267
December	268	268	268
13 Month Average	$376	$272	$272

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED DEFERRED INCOME TAXES
ACCUMULATED INVESTMENT TAX CREDITS
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

		Projected 2002			Projected 2003		
	2001	Changes	Balance	Average	Changes	Balance	Average
Accumulated Deferred Income Taxes							
Liberalized Depreciation	$3,879						
Contribution in Aid of Construction	(91)						
Customer Advances	(93)						
North Dakota Normalization	577						
Balance	$4,272	($365)	$3,907	$4,090	($314)	$3,593	$3,842
Accumulated Investment Tax Credits							
Balance	$274	($36)	$238	$256	($33)	$205	$231

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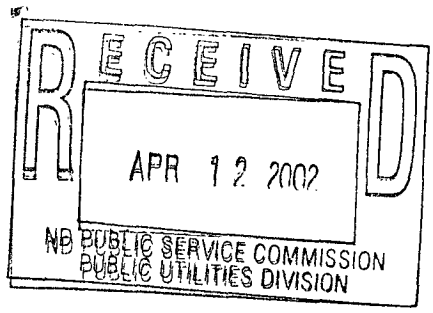

MONTANA-DAKOTA UTILITIES CO.

CASE NO. PU-399-02-___
TESTIMONY AND EXHIBITS

In the Matter of the Application of
Montana-Dakota Utilities Co. for
Authority to Establish Increased Rates
for Natural Gas Service in the
State of North Dakota

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Testimony and Exhibits

by Montana-Dakota Utilities Co., a Division of MDU Re

Exhibit # 3-9

04/12/2002 CC: Comm Legal Illona, Pat, Jerry Mike

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-___

Direct Testimony
of
C. Wayne Fox

Q. Would you please state your name and business address?

A. Yes, my name is C. Wayne Fox. My business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the President of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your duties and responsibilities with Montana-Dakota?

A. I have executive responsibility for the development, coordination and implementation of Company strategies and policies relative to all areas of operations.

Q. Would you please outline your educational and professional background?

A. In 1964, I received a Bachelor of Science degree in Electrical Engineering from Chicago Technical College, Chicago, Illinois. I received a Master of Arts degree in Business Administration from the University of Illinois, Springfield, Illinois, in 1975. Upon graduating from college in 1964, I joined the Illinois Commerce Commission, the state body regulating public utilities in Illinois, as an electrical engineer. Upon termination of my employment with the Illinois Commerce Commission in

June 1980, I was serving as Manager of the Public Utilities Division. In that capacity, my duties included testifying in formal cases before the Commission, formulating and coordinating Commission policies on technical and administrative matters, processing formal and informal cases, and advising the Commission on matters related to the regulation of public utilities operating in the state of Illinois.

In June 1980, I joined Montana-Dakota as Assistant Treasurer - Regulatory Affairs, retaining that position until May 1982 when I was elected Assistant Vice President - Regulatory Affairs. In May 1985, I was promoted to Vice President - Regulatory Affairs. In May 1987, my duties were broadened to include the Company's purchasing and general services activities. At that time, my title was changed to Vice President - Regulatory Affairs and General Services. I assumed my present position in August 2000.

I also have been involved with the activities of the Electric Power Research Institute, the Edison Electric Institute and the American Gas Association.

Q. Have you testified before this Commission and other state regulatory bodies?

A. Yes. I have previously sponsored testimony before this Commission, the Montana Public Service Commission, the Wyoming Public Service Commission, the Minnesota Public Utilities Commission and the South Dakota Public Utilities Commission.

In addition, during my tenure with the Illinois Commerce Commission, I testified in a number of cases before that Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of our North Dakota natural gas operations, explain our request for a gas rate increase and discuss the policies and reasons underlying the major aspects of the request. I will also identify the Company witnesses in this proceeding.

Q. Would you provide a summary of Montana-Dakota's gas operations in North Dakota?

A. The North Dakota natural gas distribution system serves approximately 83,500 customers in 76 communities. The customer mix is about 86.5% residential, 13.3% firm commercial, with the small interruptible and large interruptible customers making up about 0.2% of customers. In addition, gas is provided to the U.S. Air Force base at Minot and at a location in northeastern North Dakota. The residential, firm commercial and small interruptible customers use natural gas primarily for space and water heating. As such, Montana-Dakota's system has a low load factor with peak gas requirements occurring during the winter with summer loads being small by comparison. The total annual gas used by our North Dakota customers is 18.3 Mmdk as projected for 2003 in this case. Consumption by customer class is as follows: 43% residential, 31% firm commercial, 8% small interruptible, 12% large interruptible and 6% U.S. Air Force. Montana-Dakota's North Dakota gas service area is

divided into two operating regions with regional offices located in Bismarck and Dickinson. In addition, there are a number of district offices located in communities throughout the state. As of December 31, 2001, the Company had 587 full and part time employees who live and work throughout our North Dakota electric and gas service area.

Q. Mr. Fox, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for a gas rate increase?

A. Montana-Dakota is requesting an increase in its general gas rates at this time because the current cost of providing natural gas service to our North Dakota customers is not adequately reflected in the currently authorized rates. It should be noted that this application does not include any cost changes related to the cost of gas which is handled through the Commission authorized Purchased Gas Cost Adjustment tariff.

Q. Would you please explain the basic elements that make up the total costs of providing gas service and which of those elements is subject to regulation by this Commission?

A. Yes. The costs of providing natural gas service can be best broken down into two major categories; first, the cost of gas delivered to the town border station, where it leaves the interstate or intrastate pipeline and enters our distribution system, and second, the cost of delivering the gas from the town border station through our distribution system to the

individual customers. We call this portion distribution costs or non-gas costs.

Natural gas purchased from a producer or supplier is a commodity like wheat or corn and prices are not regulated. The charges for moving the gas to our distribution system on the pipeline system are regulated by the Federal Energy Regulatory Commission or other regulatory agencies. These two elements, which we call "gas costs", are passed on to our customers on a dollar-for-dollar basis as specified in the Purchased Gas Cost Adjustment tariff, and there is no profit made by Montana-Dakota. This portion currently comprises about 66% of a typical residential bill for gas service.

The distribution cost portion of our rates is regulated by this Commission and is the subject of this proceeding. This portion includes operation and maintenance expenses, depreciation, taxes, and a component for the opportunity to earn a return on the investment we have in facilities to provide natural gas service. The distribution costs are currently about 34% of a typical residential bill. The last time this portion of the rates increased was in 1994.

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting an increase of $2,844,132 based on a projected 2003 test year.

Q. How will the requested increase affect the various classes of customers?

A. The proposed percentage change in rates by customer class is as follows:

Class	Change
Residential	4.6%
Firm General Service	4.6%
Air Force	----
Small Interruptible	-4.1%
Large Interruptible	----
Total	4.1%

Q. What are the primary reasons that Montana-Dakota needs an increase at this time?

A. The primary reasons are increased operating expenses (operation and maintenance costs, depreciation and taxes other than income) and a higher required return on equity.

Q. When was the last gas general rate increase for Montana-Dakota?

A. Montana-Dakota's gas rates were last increased in November 1994. The increase was $565,000 annually and was authorized in Case No. PU-399-94-297.

Q. Have the gas general rates changed since that time?

A. Yes. In Case No. PU-399-96-325, the gas general rates were decreased by $800,000, or about 1.2%, as a result of a settlement accepted by the Commission with the lower rates becoming effective January 15, 1999.

Q. Would you please explain how Montana-Dakota has been able to hold its gas rates down since 1994?

A. From 1994 through 2001 the consumer price index has risen almost 20%. In spite of this increase, we have been able to hold the line on our gas rates by finding ways of operating our business more efficiently and taking advantage of new technologies where it makes economic sense to do so. For example, we have created a customer service center in Bismarck representing a one-stop-shop for our customers and we have installed computers in our servicemen's trucks allowing them to receive orders electronically resulting in savings of at least one hour per day. We continue to look for opportunities to reduce costs and increase efficiencies, however, we now find ourselves in a position where, despite our efforts, we must seek rate relief.

Q. What policy changes are proposed by the Company in this filing?

A. We are proposing a change in policy regarding service lines. Montana-Dakota is proposing to own all service lines on a prospective basis. Currently, Montana-Dakota owns the service lines in the communities designated as Rate Zone 2 in its tariff. The customers currently own the service lines in the communities designated as Rate Zone 1. We are proposing that Montana-Dakota will own, and pay for, subject to appropriate extension policy conditions, all new and replacement service lines on a prospective basis. This change will remove the distinction between Rate Zones 1 and 2 and will serve to form

a uniform policy on a state-wide basis for all of our service areas. It will also align the ownership of the service line with the responsibility for ongoing testing and maintenance of the lines, which rests with Montana-Dakota and will avoid customer confusion and frustration in those instances when a replacement is necessary.

Q. Is Montana-Dakota proposing changes in its rate structure in this proceeding?

A. Yes. The proposed changes in the rate structure, which will be fully described by other witnesses, accomplish the objectives of providing a measure of stability for our customers during periods of abnormal weather, being easily understandable for customers, being simple to administer and providing for enhanced fixed cost recovery. I should note that our witnesses also present an alternative proposal in the event that the Commission finds the primary proposal unacceptable. The alternative proposal is fully described in the testimony of other witnesses. I would urge the Commission to accept the primary proposal as it provides the best fit with the objectives noted above.

Q. Will you please identify the other witnesses who will testify on behalf of Montana-Dakota in this proceeding?

A. Yes. In addition to myself, Mr. J. Stephen Gaske, President of Zinder Companies, Inc., will testify regarding the appropriate cost of common equity and overall cost of capital for Montana-Dakota's electric operations. Mr. Craig A. Keller, Vice President, Controller and Chief

Accounting Officer for Montana-Dakota will testify regarding the capital structure and overall debt and preferred equity costs. Ms. Rita A. Mulkern, Regulatory Analysis Manager for Montana-Dakota, will testify regarding the total revenue requirements necessary for Montana-Dakota's North Dakota gas operations. Mr. Richard A. Espeland, Vice President – Human Resources for MDU Resources Group, Inc., will testify regarding the Supplemental Income Security Plan. Mr. Russell A. Feingold, Managing Director of Navigant Consulting, Inc., will testify regarding certain rate design policy matters and Ms. Tamie A. Aberle, Pricing and Tariff Manager for Montana-Dakota, will testify on the specific rate design proposals.

Q. Mr. Fox, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable because they are reflective of the total costs being incurred by Montana-Dakota in providing gas service to its customers. The proposed rates will allow Montana-Dakota the opportunity to earn a just and reasonable return on its North Dakota gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

Exhibit No.___(JSG-1)

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-_____

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am President of Zinder Companies, Inc., 7720 Wisconsin Avenue, Suite B-102 Bethesda, MD 20814.

Q2. Would you please describe your educational and professional background?

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also received a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates as a research assistant and later as supervisor of regulatory research. In 1980 and 1981, I was employed by Olson and Company where my primary duties were to assist in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986 I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986 I was coordinator for the Edison Electric Institute Electric Rate Fundamentals course. In 1986 I accepted an appointment as

assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988 I returned to H. Zinder & Associates as a consultant. I have testified or filed testimony or affidavits before the Federal Energy Regulatory Commission on more than twenty occasions. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, and market power. I also have filed testimony on the cost of capital and capital structure issues for electric, gas distribution and oil pipeline operations before six state regulatory bodies including North Dakota. In addition, I have testified on rate design and pricing issues before the Maine Public Utilities Commission, the Iowa Utilities Board and the Postal Rate Commission, and on issues related to generating plant economics before the Wisconsin Public Service Commission. I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on economic, competitive and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals courses. Finally, I am a member of the American Economic Association and its Transportation and Public Utilities Group, the Financial Management Association, and the AGA Rate Committee.

I. INTRODUCTION

Scope and Overview

Q3. What is the scope of your testimony in this proceeding?

A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to evaluate the required overall rate of return for the company's natural gas distribution operations in the state of North Dakota and to estimate the cost of common equity capital for those operations. In this testimony, I calculate the cost of common equity capital for Montana-Dakota's natural gas distribution operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Montana-Dakota's North Dakota natural gas distribution operations. The results of this DCF study are supported by various benchmark criteria that I have used to test the reasonableness of the DCF study results.

Q4. What rate of return is Montana-Dakota requesting in this proceeding?

A. Based on its test period capital structure, Montana-Dakota is requesting the following rate of return:

Source	Amount (000s)	Percent	Cost	Overall Rate of Return
Long-Term Debt	$132,600.0	43.039%	9.180%	3.951%
Preferred Stock	$16,250.0	5.274%	4.622%	0.244%
Common Equity	$159,245.8	51.687%	13.250%	6.849%
TOTAL	$308,095.8	100.00%		11.044%

As my testimony discusses, an overall allowed rate of return of 11.044 percent, with a 13.25 percent return on common equity, represents the cost of capital for Montana-Dakota.

Company Background

Q5. Would you please describe Montana-Dakota's operations and those of its parent company, MDU Resources Group, Inc.?

A. Montana-Dakota is a wholly-owned division of MDU Resources Group, Inc. ("MDU Resources") that is engaged in the generation, transmission and distribution of electricity, and the distribution of natural gas, in the states of North Dakota, Montana, South Dakota and Wyoming. Through other divisions and subsidiaries, MDU Resources is engaged in natural gas exploration, production and transmission and also produces and markets aggregates and other construction materials. MDU Resources also has subsidiaries engaged in utility infrastructure construction and a recently acquired division, Great Plains Natural Gas Company ("Great Plains"), distributes natural gas in southeastern North Dakota and western Minnesota.

In 2001, Montana-Dakota and the much smaller Great Plains served a total of 236,000 residential, commercial and industrial gas distribution customers. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's natural gas distribution assets comprised 7.0 percent of MDU Resources' total assets. In addition, the natural gas distribution utility revenues and operating income accounted for 11.5 percent and 1.5 percent of MDU Resources' total, respectively. North Dakota accounted for 39 percent of the natural gas distribution utility operating revenues, while Montana (25 percent), South Dakota (19 percent), Wyoming (6 percent) and Minnesota (11 percent) accounted for the other 61 percent of natural gas distribution utility revenues. Nearly all of

Montana-Dakota's gas supply is transported by Williston Basin Interstate Pipeline Company.

II. FINANCIAL MARKET STUDIES

Criteria for a Fair Rate of Return

Q6. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company?

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 603 (1944)).* There the Court described the relevant criteria as follows:

> "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That

> return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;

2. sufficient to maintain the financial integrity of the regulated company; and,

3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk there is a return that investors must expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

Q7. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A. The same standards should apply. When a regulated entity faces competition, consumers will implicitly determine the fair rate of return by their consumption decisions. When regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, the consumer and public interest also lies in establishing a return that will readily attract capital without being excessive.

Q8. How are the costs of preferred stock and long-term debt determined?

A. For purposes of setting regulated rates, the current, embedded costs of preferred stock and long-term debt are used in order to ensure that the company receives a return that is sufficient to pay the fixed dividend and interest obligations that are attached to these sources of capital.

Q9. How is the cost of common equity determined?

A. The practice in setting a fair rate of return on common equity is to use the current market cost of common equity in order to ensure that the return is adequate to attract capital and is commensurate with returns available on other investments with similar levels of risk. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a fixed level of interest or dividends is relatively easy to determine. For

example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This high degree of uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital. For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on several DCF analyses. In addition, I have conducted Risk Premium and Alternative Equity Investment analyses in order to establish benchmarks for a reasonable rate of return. Each of these approaches are described later in this testimony.

Cost of Debt

Q10. What debt cost rates have you used for Montana-Dakota?

A. Calculation of the overall cost of long-term debt and the effective cost of each of the long-term debt issues is shown in the Prepared Direct Testimony of Craig Keller, the Controller for Montana-Dakota.

Q11. What cost of preferred stock did you use?

A. Montana-Dakota's annual cost of preferred stock is 4.622 percent, as shown also in the Prepared Direct Testimony of Craig Keller.

Interest Rates and the Economy

Q12. What are the general economic factors that affect the cost of capital?

A. Investors are often influenced by their perceptions of the economy and both short- and long-term trends. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows various general economic statistics. The economy has had a record of persistent growth during the past thirty years, with only temporary recessionary periods. Real growth in the Gross Domestic Product ("GDP") has averaged 3.2 percent annually during the past 30 years, 3.1 percent for the past 20 years and 3.1 percent for the past ten years. However, the economy recently has been shrinking and in a recession. Although there are signs that the recession may be ending, recent reports indicate that manufacturing jobs continue to decline. In addition, utility stock prices in general are lower now than they were prior to September 11. The decline in utility stock market prices was partially the result of an increase in the perceived risk of utility equity investments.

Investors also are influenced by the level of inflation, which has been persistent in the past. During the past decade, the Consumer Price Index has increased at an average annual rate of 2.8 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 2.1 percent.

Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates provide a standard measure of returns currently available on less risky securities. As Page 2 of Schedule 1 of Exhibit No. ___(JSG-2) shows, long-term interest rates have remained

relatively stable during the past two years. The recent yields on A-rated public utility bonds have been approximately 7.6 percent and the yields on Baa-rated public utility bonds have been approximately 8.0 percent.

Discounted Cash Flow ("DCF") Method

Q13. Please describe the DCF method of estimating the cost of common equity capital.

A. The DCF method reflects the assumption that the market price of a share of stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield, plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital with the DCF method therefore is a matter of calculating the current dividend yield and estimating the long-term future growth rate in dividends that investors reasonably expect from a company.

The dividend yield portion of the DCF method utilizes readily-available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives. However, the other component of the DCF formula, investors' expectations regarding the future long-run

growth rate of dividends, is not readily apparent from stock market data and must be estimated using informed judgment.

Q14. What is the appropriate DCF formula to use in this proceeding?

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend increase is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by (1 + .75 g). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by (1 + .5 g). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D\,(1 + .625g)}{P} + g \qquad (1)$$

where:
- K = the cost of capital, or total return that investors expect to receive;
- P = the current market price of the stock;
- D = the current annual dividend rate; and
- g = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

Flotation Cost Adjustment

Q15. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

A. Yes. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital. Schedule 3 of Exhibit No. ___(JSG-2) shows a representative sample of flotation costs incurred with 34 new common stock issues by natural gas transmission and distribution companies between 1992 and 2001. Flotation costs associated with these new issues averaged 4.85 percent. This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Montana-Dakota must have an expected return that places a value on its equity that is approximately 4.75 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.0475.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important

purpose of a flotation cost adjustment is to establish a return that is sufficient to enable a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

DCF Study of Natural Gas Distribution Companies

Q16. Would you please describe the overall approach used in your DCF analysis of Montana-Dakota's cost of common equity?

A. Because Montana-Dakota must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method provides a good measure of the returns required by investors in the financial markets. However, the DCF method requires a market price of common stock to compute the dividend yield component of the DCF analysis. Since Montana-Dakota is a division of MDU Resources and does not have publicly-traded common stock, a direct, market-based DCF analysis of Montana-Dakota's natural gas distribution operation as a stand-alone company is not possible. To get around this problem, I have used the Moody's Natural Gas Distribution Companies as a

proxy group for purposes of estimating the cost of common equity for Montana-Dakota's North Dakota natural gas distribution operations.

Q17. How did you calculate the dividend yields for the companies in your comparison group?

A. These calculations are shown on page 3 of Schedule 2 of Exhibit No. __(JSG-2). For the price component of the calculation I used the average of the high and low stock prices experienced by each company during the six month period from August 2001 to January 2002. The dividend yields were calculated for each company by dividing the indicated annual dividend by the average of the stock prices for each company. These dividend yields can be multiplied by the quarterly DCF model factor (1 + .625 g) to arrive at the dividend yield component of the DCF model.

Q18. Please describe the method you used in estimating the future growth rate that investors expect from this group of companies?

A. I developed three different DCF analyses of the proxy companies based on three different growth rate estimation methods. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect.

In the first approach I calculated a DCF rate of return using a combination of securities analysts' growth projections and the Value Line retention growth forecasts to produce a Second-Stage Retention Growth analysis. As a second approach, I conducted a Basic DCF analysis that relied solely on the analysts'

forecasts for the growth rate component of the model. Finally, my Primary DCF uses a variety of sources and analyses to develop an estimate of the composite growth rate that investors would expect from the sample group of proxy companies.

Second-Stage Retention Growth Analysis

Q19. How did you use your Second-Stage Retention Growth analysis to estimate investors' long-term growth rate expectations for the proxy companies?

A. The Second-Stage Retention Growth rate approach combines: (i) estimates of long-term growth for each company that are published by various investment analysts and (ii) Value Line retention growth forecasts.

Q20. How did you estimate the first stage of expected future growth?

A. Among the best sources of information regarding investors' growth rate expectations are the long-term earnings growth rate forecasts of investment analysts. Zack's is a service that collects estimates by professional investment analysts and publishes a summary of the consensus forecasts. I have used the Zack's consensus forecasts as the source for analysts' forecasts in my calculations. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 5, the average of the analysts' long-term growth rate estimates for the natural gas distribution proxy companies is 7.6 percent.

Q21. Would you please describe the second stage, retention growth rate component of your analysis?

A. In addition to analysts' growth rate forecasts, I have relied upon Value Line projections of the retention growth rates that the proxy companies are

expected to begin maintaining three to five years in the future. Although companies may experience extended periods of growth for other reasons, in the long-run, growth in earnings and dividends per share depends in part on the amount of earnings that are being retained and reinvested in a company. Thus, the primary determinants of growth for the proxy companies will be (i) their ability to find and develop profitable opportunities; (ii) their ability to generate profits that can be reinvested in order to sustain growth; and, (iii) their willingness and inclination to reinvest available profits. Expected future retention rates provide a general measure of these determinants of expected growth, particularly items (ii) and (iii).

Q22. How can a company's earnings retention rate affect its future growth?

A. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that are generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (b) times the rate of return on common equity (r) that a company is expected to earn in the future. For example, a company that is expected to earn a return of 15 percent and retain 80 percent of its earnings might be expected to have a growth rate of 12 percent, computed as follows:

$$.80 \times 15\% = 12\%$$

On the other hand, another company that is also expected to earn 15 percent but only retains 20 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$.20 \times 15\% = 3\%$$

Thus, the rate of growth in a firm's book value per share is primarily determined by the level of earnings and the proportion of earnings retained in the company.

Q23. How did you calculate the expected future retention rates of the proxy companies?

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have 3-5 years in the future. Since these retention rates are projected for several years in the future they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect 3-5 years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 4 of Schedule 2 of Exhibit No.___(JSG-2). The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that are being retained and reinvested in the company. This earnings retention rate is multiplied times the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 5.5 percent.

Q24. How did you utilize the projected earnings retention rates in estimating expected growth for the proxy companies?

A. As shown on page 5 of Schedule 2 of Exhibit No.___(JSG -2), I calculated a weighted average of the analysts' projected growth rates and the projected retention growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave a two-thirds weighting to the analysts' growth rate projections to reflect the fact that analysts are attempting to evaluate all sources of growth and not just growth that is expected to result from retained earnings. This weighting also reflects the fact that the analysts' long-term growth forecasts can be expected to prevail for a relatively long period of time in the future. This two-thirds weighting for analysts' forecasts is the same weighting that the FERC used in Opinion No. 414-A for setting the allowed return on equity for natural gas pipeline companies. *Transcontinental Gas Pipeline Co.*, 80 FERC ¶ 61,084 (1998). The average of the weighted average growth rates for the proxy companies is 6.9 percent and the median is 6.7 percent.

Q25. How did you utilize these Second-Stage Retention Growth rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A. The dividend yield for each company shown on page 3 of Schedule 2 of Exhibit No.___(JSG-2) is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.0475 to arrive at the cost of common equity

capital for the proxy companies. These calculations are shown on page 6 of Schedule 2 of Exhibit No.___(JSG-2). This Second-Stage Retention Growth DCF analysis indicates that the cost of common equity capital for the natural gas distribution proxy companies is in a range between 9.7 percent and 16.1 percent. The median for the group is 12.5 percent and the average for the group is 12.8 percent.

Basic DCF Analysis

Q26. What approach did you use in conducting a Basic DCF analysis?

A. This analysis is conducted in substantially the same manner as the Second-Stage Retention Growth Rate analysis. However, the growth rate component of the analysis is based solely on the analysts' forecasts for each company and the retention growth rate component is omitted from the analysis. This Basic DCF analysis recognizes that the consensus of analysts' forecasts reflects the most important component of investors' growth rate expectations and it assumes that the analysts' forecasts incorporate all information required to estimate a long-term expected growth rate for a company.

Q27. How did you calculate the cost of capital using the Basic DCF analysis?

A. These calculations are shown on page 7 of Schedule 2 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.0475 to arrive

at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a median cost of common equity for the proxy companies of 13.2 percent and an average cost of 13.6 percent.

Primary DCF Analysis

Q28. Would you please describe your Primary DCF analysis?

A. My primary DCF approach refines the growth rate estimates to reflect my analysis of the appropriate range of growth rate expectations that are implicit in the stock prices and dividend yields of this group. As the following analysis indicates, my primary analysis indicates a DCF required rate of return that is quite close to the level that is indicated by both the Second-Stage Retention Growth DCF analysis and the Basic DCF analysis.

Q29. In your opinion, what are the factors that will affect growth rates for the proxy companies in the future?

A. One important factor will be growth in the overall economy. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows that the United States Gross Domestic Product has grown at an average annual rate of 7.6 percent during the past 30 years. During the past decade U.S. GDP growth has averaged 5.5 percent. It is reasonable to expect that long-term future growth in the economy generally will be comparable to past growth rates. For example, DRI-WEFA forecasts that the U.S. GDP will grow at a rate of approximately 5.9 percent over the long-term.

Another factor will be demand for natural gas. Natural gas usage has been increasing in recent years and many analysts are expecting demand to increase

steadily during the next decade and beyond. For example, the Energy Information Administration of the U.S. Department of Energy forecasts that gas consumption in the United States will grow from its current level of approximately 23 Tcf per year to approximately 34 Tcf per year in 2020. Steady increases in demand for gas distribution services of the proxy companies should be fueled by the availability of domestic and imported supplies and the superior environmental characteristics of natural gas that should allow it to achieve a greater market share relative to other fuels. While the real gas distribution capacity of the proxy companies is expected to increase, additional growth will occur because the amount of investment required will increase in nominal dollars. In other words, the effects of inflation needs to be added to the real growth rate in the industry to get a measure of likely growth in investment and earnings.

In my opinion, investors reasonably expect the six companies in this comparison group to grow at a rate that is somewhere in the range of 6.75 percent to 7.75 percent. Based on the average growth rate of approximately 7.6 percent currently projected by investment analysts, as well as the 5.9 percent growth rate in the economy, increasing demands for natural gas, and my review of these companies, I consider this growth rate range to be a reasonable estimate of the future growth expectations that are implicit in current dividend yields. This growth rate range is also consistent with the retention growth rates projected for these companies and their ability to grow by means other than retained earnings.

Q30. What does your primary DCF analysis indicate with regard to investors' current market rate of return requirements?

A. Page 8 of Schedule 2 of Exhibit No. ___(JSG-2) shows the calculation of the cost of capital based on my primary DCF growth rate estimates. The dividend yield used in this analysis is the average dividend yield for the natural gas distribution proxy companies that is developed on page 3 of Schedule 2. This market-based primary DCF analysis indicates that the cost of capital for the proxy companies is approximately in the range of **12.7 percent** to **13.8 percent**.

Risk Premium Analyses

Q31. Have you conducted additional analyses in determining the cost of capital to Montana-Dakota?

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of bondholders. This superior standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing

in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual returns on large company common stocks have exceeded the yields on Long-Term U.S. Government Bonds by an average of 780 basis points (7.8 percent). However, the returns on relatively small company stocks in the size range of Montana-Dakota's natural gas distribution operations have been 1,520 basis points (15.2 percent) above the yields on long-term government bonds. As shown on page 1 of Schedule 2 of Exhibit No. ___ (JSG-2), Montana-Dakota is a fraction of the size of any of the proxy companies. In recent months, the yield on long-term U.S. Government bonds has been approximately 5.5 percent. Adding a 7.8 percent premium to a yield of 5.5 percent indicates that investors in large company common stocks require a return of at least 13.3 percent. Adding the 15.2 percent premium for companies in Montana-Dakota's size range suggests a required return of 20.2 percent.

Another risk premium approach is to examine the long-term premium of large company common stock returns as compared with returns on corporate bonds. This premium has averaged 740 basis points (7.4 percent) annually over a long period of time in the past. When this premium is added to the 7.4 percent yield on

Moody's corporate bonds that has prevailed in recent months, the result is an investor return requirement for large company stocks of 14.8 percent. However, over the long-term companies in Montana-Dakota's size range have had a premium of 1,480 basis points (14.8 percent) over the average returns on long-term corporate bonds. When added to the recent average corporate bond yields, this size-related premium suggests an expected return of 22.2 percent.

Alternative Equity Investment Analysis

Q32. Have you analyzed the returns available on common equity investments in other industries?

A. Yes. When investors consider whether to invest their funds in a particular company or line of business, they evaluate the returns potentially available from other companies. This process whereby projects and companies compete for scarce equity capital ensures that capital resources are deployed efficiently. As a result, regulated natural gas distribution operations must bid against other companies and other possible projects within the same company for equity capital by offering potential returns that investors find attractive relative to the risks involved.

Q33. What level of returns are potentially available to unregulated companies?

A. The potential returns are often considerably above 20 percent and the average returns for broad-based, diversified portfolios have averaged 20.0 percent or more in recent years. For example, page 3 of Schedule 1 of Exhibit No. ___(JSG-2) shows the average return on equity book value earned by companies in the S&P 500 each year from 1977 to 2000. It can be seen, in fact, that average returns for the

S&P 500 companies have been 21.47 percent for the past five years. For purposes of comparison with allowed returns for regulated natural gas distribution operations, a better indicator of earnings on alternative equity investments is provided by data on 746 industrial, retail and transportation companies published by *The Value Line Investment Survey*. Excluding extraordinary and non-recurring items, the average returns on the original cost book value of common equity for these companies in recent years has been:

1996	27.57%
1997	29.35
1998	28.28
1999	30.08
2000	31.75
5-year Average	**29.41%**

Q34. Is it appropriate to set the allowed rate of return for a natural gas distribution company equal to the average return available to industrial companies?

A. The average return for industrials serves as a useful indicator of the cost of capital because natural gas distribution companies must offer potential returns that are competitive with other investments in order to attract capital. It is important to remember that an industrial company has an opportunity to earn returns far in excess of 20 percent. In fact, the average company has earned normal returns on the book value of equity well in excess of 20 percent in recent years. This average reflects many companies that experienced enormous losses as well as those with large returns.

Similarly, when a regulator sets an allowed return it is providing only an *opportunity* to earn that return. In exceptionally good times a regulated company might earn slightly more than this amount, but it might earn substantially less than the allowed return and, in fact, often does earn less than that amount. Natural gas distribution companies generally have risks that are less than those of the average large industrial company. Consequently, it would be appropriate to view average returns earned by a broad cross-section of industry as being only a general indicator for reasonable allowed returns.

As a benchmark, allowed returns for natural gas distribution companies can be compared to returns on book value for large companies. Normal returns have averaged 29.4 percent during the past five years. Similarly, the average level of return experienced by the S&P 500 companies has been approximately 21.47 percent. As this comparison indicates, an allowed return of 13.25 percent for Montana-Dakota would be quite low in comparison with the returns earned by other large companies. Consequently, a return of this magnitude could potentially be too low for Montana-Dakota's natural gas distribution operations to successfully compete for capital.

Relative Risk Analysis

Q35. Have you compared the risks faced by Montana-Dakota's North Dakota natural gas distribution operations with the risks faced by the proxy group of companies?

A. Yes. There are four broad categories of risk that concern investors. These include:

i. Business Risk;
ii. Regulatory Risk;
iii. Financial Risk; and,
iv. Market Risk.

Q36. Would you please describe the business risks inherent in the natural gas distribution industry?

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived natural gas distribution assets, for which cost recovery occurs over a period of thirty years or more, are subject to enormous uncertainties and risks that demand, costs, supply and competition may change in ways that adversely affect the value of the investment.

Q37. What are some of the business risks faced by Montana-Dakota's North Dakota natural gas distribution operations?

A. These operations face many of the same risks that are associated with other natural gas distribution companies. However, Montana-Dakota's gas distribution operation faces some risks that distinguish it from many other distribution companies.

As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's natural gas distribution operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the typical proxy company. For example, Montana-Dakota's natural gas distribution assets are equal to only 7.2 percent of the assets of the median proxy company.

Similarly, Montana-Dakota's gas distribution operating revenues and operating income are only 17.1 percent and 2.2 percent of the level for the median proxy company. Thus, depending upon the measure of size, the typical proxy company is somewhere between approximately six and 46 times the size of Montana-Dakota's natural gas distribution operations. With its small revenue base, Montana-Dakota is subject to slightly greater risk that a major employer or industry, such as a mining operation or refinery, might experience a downturn that would significantly affect overall employment and income in the areas served.

Ibbotson Associates has documented the significantly higher returns that generally have been associated with small companies. On a practical level, Montana-Dakota's relatively small natural gas distribution operations are heavily dependent upon a relatively undiversified local economy. Factors that negatively influence the local economy can reduce demand for Montana-Dakota's gas distribution services and adversely impact investments in facilities used to provide those services. Considering only its smaller size, Montana-Dakota might require a return that is more than 100 basis points higher than the return required for the typical proxy company.

In addition, Montana-Dakota faces direct competition from propane and heating oil for new and existing load in its North Dakota service territory. Another risk faced by Montana-Dakota is the fact that it recovers a substantial portion of its fixed costs in the volumetric component of its rates and it does not have a weather normalization adjustment mechanism. In contrast, several of the proxy companies have rate designs that better reflect the fixed cost nature of their

operations. These companies have slightly less rate design risk as a result. Montana-Dakota is requesting in this filing a rate design that better reflects costs, but until such rate design is approved, Montana-Dakota's North Dakota gas distribution operations face somewhat greater overall business risk than the typical company in the natural gas distribution proxy group.

Q38. What are the regulatory risks faced by Montana-Dakota's North Dakota utility operations?

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for a natural gas distribution company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow full cost recovery. In effect, the binding constraint on utilities is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for competition where markets are not workably competitive. As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries. Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of gas distribution utilities to finance their operations. Thus, in some instances regulation may substitute for competition and in other instances it may limit the potential returns available to successful competitors. In either case, regulatory risk is an important

consideration for investors and has a significant effect on the cost of capital for all firms in the natural gas distribution industry.

Value Line rates the regulatory climate in North Dakota as being "average," thus, Montana-Dakota should be considered to have average regulatory risk relative to the proxy companies.

Q39. Would you please describe Montana-Dakota's relative financial risks?

A. Financial risk exists to the extent a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from bond ratings. Because Montana-Dakota does not have its own bonds outstanding, it is difficult to make direct comparisons between the ratings of Montana-Dakota and the proxy group. However, page 2 of Schedule 2 of Exhibit No. ___ (JSG-2) shows the bond ratings assigned by Moody's and Standard & Poor's to each of the companies in the comparison group and MDU Resources bonds that are secured by the assets of Montana-Dakota Utilities. The median bond ratings for companies in the proxy group are AA-/A+ for Standard & Poor's and A1 for Moody's. In comparison, MDU Resources bonds carry an A+ rating with Standard & Poor's and an A2 rating with Moody's. This suggests that the perceived risk of MDU Resources' bonds is slightly greater than that of

the typical company in the comparison group. Examination of the capital structure data shown on page 9 of Exhibit No. ___ (JSG-2), Schedule 2 shows that Montana-Dakota's filed common equity ratio, 51.7 percent, is very close to the median for the proxy companies. This common equity ratio, combined with its bond rating, suggests average financial risk for Montana-Dakota's North Dakota natural gas distribution operations.

Q40. Would you please describe Montana-Dakota's market risks?

A. Market risk is associated with the changing value of all investments because of business cycles, inflation and fluctuations in the general cost of capital throughout the economy. Different companies are subject to different degrees of market risk largely as a result of differences in their business and financial risks. Because of the substantial similarity in their operations, Montana-Dakota's degree of market risk is not significantly different from that of the companies in the natural gas distribution comparison group.

Q41. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's natural gas distribution operations?

A. Montana-Dakota faces overall risks that are above average relative to those of the proxy companies. Montana-Dakota has above-average business risks due primarily to its exceptionally small size relative to the proxy companies and its exposure to a relatively undiversified economy. Montana-Dakota also has slightly greater rate design risk than the typical company in the proxy group. On the other hand, it has average financial risks. These factors and the perception of an average regulatory climate in North Dakota lead me to conclude that the overall risks of

Montana-Dakota's natural gas distribution operations are somewhat above average relative to the risks of the proxy companies.

III. SUMMARY AND CONCLUSIONS

Q42. Would you please summarize the results of your cost of capital study?

A. Yes. I conducted several DCF analyses on a group of natural gas distribution companies that have a range of risks that includes risks roughly comparable to those of Montana-Dakota. The results of my various analyses can be summarized as follows:

	Investor Requirement Median/Average	Cost of Capital Median/Average
DCF Analyses		
Natural gas distribution Proxies:		
- Second-Stage Retention Growth	11.94%	12.51%
- Basic DCF	12.61%	13.21%
- Primary DCF	12.63%	13.22%
Benchmark Analyses		
Risk Premium Return Based On:		
- U.S. Treasury Bonds		
v. Large Companies	13.3	
v. Small Companies	20.2	
- Corporate Bonds		
v. Large Companies	14.8	
v. Small Companies	22.2	
Alternative Investments		
- S&P 500	21.5	
- Value Line Industrials	29.4	

My second-stage retention growth analysis indicates a median cost of common equity capital of 12.5 percent. Because projected retention growth is sustainable indefinitely and it is directly related to the growth rate expectations for an individual company, it is a good indicator of the minimum growth rate that a company can maintain in the very long run. However, companies can achieve growth through means in addition to retained earnings. Consequently, analysts' forecasts provide the best measure of expected growth for the foreseeable future. Combining these two measures provides a good estimate of the long-term growth that investors can reasonably expect from these proxy companies.

The Basic DCF analysis, which relies solely on the analysts' forecasts, also provides a good estimate of investors' growth rate expectations and required return for the proxy companies. This DCF analysis indicates a median required rate of return of 13.2 percent.

My primary approach has been to analyze a variety of sources of information, including investment analysts' forecasts, in order to estimate a weighted average annual growth rate that investors reasonably can expect the natural gas distribution comparison companies to achieve during a long period of time in the future. This primary DCF analysis indicates that the cost of capital for natural gas distribution companies with risks comparable to those of Montana-Dakota is in a range between 12.7 percent and 13.8 percent. The mid-point of this range is approximately 13.2 percent.

My risk premium analyses indicate that my DCF estimates produce a premium over corporate bond yields that is below the average long-run risk

premium available from common stocks. The DCF return estimates provide a premium over the return on corporate bonds that is considerably below the average premium experienced by companies in Montana-Dakota's relative size range. In addition, my examination of returns available on alternative equity investments suggests that my DCF estimates generally are significantly below the 21.5 percent average return earned by the S&P 500 companies during the past five years. Moreover, the DCF returns are far below the 29.4 percent average normal returns earned by the Value Line Industrials in recent years.

Q43. What rate of return on common equity do you recommend for Montana-Dakota in this proceeding?

A. My analyses indicate that an appropriate rate of return on common equity for Montana-Dakota's North Dakota natural gas distribution operations at this time would be **13.25 percent**. This recommended return reflects my assessment that Montana-Dakota's overall risks are slightly above-average relative to the proxy group. A return of 13.25 percent is very near the middle of the range for my Primary DCF analysis and also is very close to the median for my Basic DCF analysis. It also is above the median return calculated using a Second-Stage Retention Growth analysis and, thus, appropriately reflects the above-average risks faced by Montana-Dakota.

Q44. Does this conclude your Prepared Direct Testimony?

A. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1971-2001

Year	Percentage Price Changes: Consumer Price Index	Percentage Price Changes: GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP (Billions)
1971	4.4%	5.0%	3.3%	1,128.6
1972	3.2%	4.3%	5.4%	1,240.4
1973	6.2%	5.6%	5.8%	1,385.5
1974	11.0%	9.0%	-0.6%	1,501.0
1975	9.1%	9.3%	-0.4%	1,635.2
1976	5.8%	5.7%	5.6%	1,823.9
1977	6.5%	6.4%	4.6%	2,031.4
1978	7.6%	7.1%	5.5%	2,295.9
1979	11.3%	8.3%	3.2%	2,566.4
1980	13.5%	9.2%	-0.2%	2,795.6
1981	10.3%	9.3%	2.5%	3,131.3
1982	6.2%	6.2%	-2.0%	3,259.2
1983	3.2%	4.0%	4.3%	3,534.9
1984	4.3%	3.7%	7.3%	3,932.7
1985	3.6%	3.1%	3.8%	4,213.0
1986	1.9%	2.2%	3.4%	4,452.9
1987	3.6%	3.0%	3.4%	4,742.5
1988	4.1%	3.4%	4.2%	5,108.3
1989	4.8%	3.8%	3.5%	5,489.1
1990	5.4%	3.9%	1.8%	5,803.2
1991	4.2%	3.6%	-0.5%	5,986.2
1992	3.0%	2.4%	3.0%	6,318.9
1993	3.0%	2.4%	2.7%	6,642.3
1994	2.6%	2.1%	4.0%	7,054.3
1995	2.8%	2.2%	2.7%	7,400.5
1996	3.0%	1.9%	3.6%	7,813.2
1997	2.3%	1.9%	4.4%	8,318.4
1998	1.6%	1.2%	4.3%	8,781.5
1999	2.2%	1.4%	4.1%	9,268.6
2000	3.4%	2.3%	4.1%	9,872.9
2001	2.8%	2.2%	1.2%	10,205.6
Average Rate of Change: 1/				
1971-2001	5.1%	4.4%	3.2%	7.6%
1981-2001	3.7%	3.2%	3.1%	6.1%
1991-2001	2.8%	2.1%	3.1%	5.5%

1/ Nominal GDP growth rates are based on the geometric average rate of change in nominal GDP.

Source: *Economic Report of the President*, February 2002 and U.S. Department of Commerce, Bureau of Economic Analysis.

Montana-Dakota Utilities Co.

Moody's Bond Yield Averages
January 2000 - January 2002

		Average Corporate	Public Utility Bonds	
			A-Rated	Baa-Rated
2000	JAN	8.06	8.35	8.40
	FEB	7.96	8.25	8.33
	MAR	7.99	8.28	8.40
	APR	7.98	8.29	8.40
	MAY	8.41	8.70	8.86
	JUN	8.05	8.36	8.47
	JUL	7.98	8.25	8.33
	AUG	7.88	8.13	8.25
	SEP	7.98	8.23	8.32
	OCT	7.95	8.14	8.29
	NOV	7.90	8.11	8.25
	DEC	7.65	7.84	8.01
2001	JAN	7.55	7.80	7.99
	FEB	7.50	7.74	7.94
	MAR	7.41	7.68	7.85
	APR	7.63	7.94	8.06
	MAY	7.69	7.99	8.11
	JUN	7.56	7.85	8.02
	JUL	7.51	7.78	8.05
	AUG	7.37	7.59	7.95
	SEP	7.54	7.75	8.12
	OCT	7.41	7.63	8.02
	NOV	7.32	7.57	7.96
	DEC	7.55	7.83	8.27
2002	JAN	7.38	7.66	8.13

Source: Mergent Bond Record.

Montana-Dakota Utilities Co.

Average Return on Book Value of Equity for S&P 500 Companies

	Average Return on Equity	5-Year Moving Average ROE
2000	23.17	21.47
1999	23.49	20.69
1998	18.50	19.77
1997	20.89	18.99
1996	21.30	17.33
1995	19.27	15.12
1994	18.90	14.10
1993	14.57	13.43
1992	12.60	13.88
1991	10.25	13.97
1990	14.20	14.20
1989	15.53	13.70
1988	16.81	13.31
1987	13.05	12.35
1986	11.43	11.99
1985	11.67	12.51
1984	13.59	13.07
1983	12.00	13.50
1982	11.24	13.99
1981	14.04	14.50
1980	14.46	
1979	15.76	
1978	14.45	
1977	13.77	

Montana-Dakota Utilities Co.

Moody's Natural Gas Distribution Companies
Fiscal Year 2001 Operating Data

	Assets ($000,000)	Operating Revenues ($000,000)	Operating Income ($000,000)
AGL Resources, Inc.	$3,368	$1,049	$209
Keyspan Corp.	$11,790	$6,633	$801
The Laclede Group, Inc.	$976	$1,002	$72
Northwest Natural Gas Co. **	$1,355	$532	$104
Peoples Energy Corp.	$2,994	$2,270	$162
WGL Resources, Inc.	$2,081	$1,940	$206
High	$11,790	$6,633	$801
Median	**$2,538**	**$1,494**	**$184**
Low	$976	$532	$72
Montana-Dakota Gas Distribution*	**$183**	**$255**	**$4**
MDU Resources Group, Inc.	$2,623	$2,224	$273
Montana-Dakota Gas Distribution % of:			
- Proxy Company Median	**7.2%**	**17.1%**	**2.2%**
- MDU Resources Group, Inc.	7.0%	11.5%	1.5%

* Also includes Results for Great Plains Natural Gas Co.

** Assets as of 9/30/2001; Operating Revenues and Income for 2000.

Sources: Zacks.com; Annual Reports and 10-K's.

Montana-Dakota Utilities Co.

Bond Ratings of
Moody's Natural Gas Distribution Companies

	Standard & Poor's	Moody's
AGL Resources, Inc.	A-	A3
Keyspan Corp.	A+	A2
The Laclede Group, Inc.	AA-	Aa3
Northwest Natural Gas Co.	A	A2
Peoples Energy Corp.	AA-	Aa2
WGL Resources, Inc.	AA-	Aa2
Median	AA-/A+	A1
MDU Resources Group	A+	A2

Source: C.A. Turner, *Utility Reports*, February 2002.

Montana-Dakota Utilities Co.

Moody's Natural Gas Distribution Companies
Dividend Yields
August 2001 - January 2002

		Stock Price August '01 - January '02				
		High	Low	Average	Dividend	Yield
AGL Resources, Inc.	ATG	$ 25.15	$ 18.95	$ 22.05	$ 1.08	4.90%
Keyspan Corp.	KSE	$ 35.55	$ 29.85	$ 32.70	$ 1.78	5.44%
The Laclede Group, Inc.	LG	$ 25.35	$ 21.95	$ 23.65	$ 1.34	5.67%
Northwest Natural Gas Co.	NWN	$ 27.99	$ 22.00	$ 25.00	$ 1.26	5.04%
Peoples Energy Corp.	PGL	$ 42.94	$ 35.40	$ 39.17	$ 2.04	5.21%
WGL Resources, Inc.	WGL	$ 29.75	$ 25.30	$ 27.53	$ 1.26	4.58%
Average						5.14%
Median						5.12%

Sources: America Online and Wall Street Journal, Feb. 1, 2002.

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Moody's Natural Gas Distribution Companies

	Value Line Forecast 2004-2006				
	EPS	DPS	ROE	Retention Rate	Retention Growth
AGL Resources, Inc.	$ 2.05	$ 1.16	13.50%	43.41%	5.9%
Keyspan Corp.	$ 3.80	$ 1.86	13.50%	51.05%	6.9%
The Laclede Group, Inc.	$ 2.15	$ 1.45	13.00%	32.56%	4.2%
Northwest Natural Gas Co.	$ 2.40	$ 1.30	11.00%	45.83%	5.0%
Peoples Energy Corp.	$ 4.05	$ 2.16	12.00%	46.67%	5.6%
WGL Resources, Inc.	$ 2.55	$ 1.35	12.00%	47.06%	5.6%
Average					5.5%
MDU Resources	$ 2.50	$ 1.06	10.00%	57.60%	5.8%

Source: *Value Line*, December 21, 2001 and February 15, 2002.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth Rate
Estimates for Moody's Natural Gas Distribution Companies

		2/3 Zacks 5-Yr Earnings Growth Est.	1/3 Retention Growth	Weighted Average
AGL Resources, Inc.	ATG	7.03%	5.9%	6.64%
Keyspan Corp.	KSE	7.83%	6.9%	7.52%
The Laclede Group, Inc.	LG	12.00%	4.2%	9.41%
Northwest Natural Gas Co.	NWN	7.50%	5.0%	6.68%
Peoples Energy Corp.	PGL	7.00%	5.6%	6.53%
WGL Resources, Inc.	WGL	4.00%	5.6%	4.55%
Average		7.6%	5.5%	**6.9%**
Median				**6.7%**

Sources: Zacks.com and page 4.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth DCF Calculation for Moody's Natural Gas Distribution Companies

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Investor Required Return	Flotation Cost Adjustment	Cost of Capital
AGL Resources, Inc.	4.90%	5.10%	6.64%	11.74%	1.0475	12.30%
Keyspan Corp.	5.44%	5.70%	7.52%	13.22%	1.0475	13.84%
The Laclede Group, Inc.	5.67%	6.00%	9.41%	15.41%	1.0475	16.14%
Northwest Natural Gas Co.	5.04%	5.25%	6.68%	11.93%	1.0475	12.50%
Peoples Energy Corp.	5.21%	5.42%	6.53%	11.95%	1.0475	12.52%
WGL Resources, Inc.	4.58%	4.71%	4.55%	9.26%	1.0475	9.70%
Average	5.14%		6.89%	12.25%		**12.83%**
High				15.41%		16.14%
Median				11.94%		**12.51%**
Low				9.26%		9.70%

Case No. _____
Exhibit No. ___(JSG-2)
Schedule 2
Page 6 of 9

Montana-Dakota Utilities Co.

Basic DCF Calculation
for Moody's Natural Gas Distribution Companies

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Investor Required Return	Flotation Cost Adjustment	Cost of Capital
AGL Resources, Inc.	4.90%	5.11%	7.03%	12.14%	1.0475	12.72%
Keyspan Corp.	5.44%	5.71%	7.83%	13.54%	1.0475	14.18%
The Laclede Group, Inc.	5.67%	6.09%	12.00%	18.09%	1.0475	18.95%
Northwest Natural Gas Co.	5.04%	5.28%	7.50%	12.78%	1.0475	13.38%
Peoples Energy Corp.	5.21%	5.44%	7.00%	12.44%	1.0475	13.03%
WGL Resources, Inc.	4.58%	4.69%	4.00%	8.69%	1.0475	9.10%
Average	5.14%		7.56%	12.95%		**13.56%**
High				18.09%		18.95%
Median				12.61%		**13.21%**
Low				8.69%		9.10%

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Exhibit No. ___(JSG-2)
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Montana-Dakota Utilities Co.

Primary DCF Analysis
Computation of the Cost of Capital
for Moody's Natural Gas Distribution Companies

Growth Rate Estimate (g)	6.75%		7.75%
Current Dividend Yield (D/P)	5.14%		5.14%
Quarterly Model Dividend Yield Factor (1 + .625 g)	X 1.042		X 1.048
DCF Dividend Yield Component (Y)	5.36%		5.39%
Investor Required Return (Y + g)	12.11%		13.14%
Flotation Cost Adjustment	X 1.0475		X 1.0475
Cost of Capital	12.69%		13.76%
Mid-Point		**13.22%**	

Montana-Dakota Utilities Co.

Moody's Natural Gas Distribution Companies
Capital Structures as of September 30, 2001

	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
AGL Resources, Inc.	$ 890.0	49.96%	$ -	0.00%	$ 891.3	50.04%	$ 1,781.3
Keyspan Corp.	$ 4,809.6	60.11%	$ 84.1	1.05%	$ 3,108.0	38.84%	$ 8,001.7
The Laclede Group, Inc.	$ 284.5	49.55%	$ 1.6	0.28%	$ 288.1	50.18%	$ 574.1
Northwest Natural Gas Co.	$ 418.4	46.31%	$ 34.0	3.76%	$ 451.1	49.93%	$ 903.6
Peoples Energy Corp.	$ 644.3	44.44%	$ -	0.00%	$ 805.5	55.56%	$ 1,449.8
WGL Resources, Inc.	$ 632.5	43.65%	$ 28.2	1.94%	$ 788.3	54.40%	$ 1,449.0
Average		**49.00%**		**1.17%**		**49.82%**	
Median		**47.93%**		**0.66%**		**50.11%**	

Sources: Zacks.com.

Case No. _____
Exhibit No. ___(JSG-2)
Schedule 2
Page 9 of 9

Montana-Dakota Utilities Co.

Common Equity Flotation Costs of Natural Gas Distribution/Transmission Companies 1992-2001

Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Bay State Gas Co.	3/13/1992	1,550,000	$23.250	$22.280	4.35%
El Paso Natural Gas Co.	5/12/1992	5,000,000	$19.000	$17.770	6.92%
New Jersey Resources Co.	9/15/1992	1,500,000	$22.250	$21.270	4.61%
Washington Energy Co.	9/29/1992	2,750,000	$21.000	$20.190	4.01%
Equitable Resources	9/22/1993	2,400,000	$38.500	$37.250	3.36%
Brooklyn Union Gas	9/29/1993	1,700,000	$25.750	$24.770	3.96%
S.E. Michigan Gas Enterprises	1/19/1994	650,000	$20.500	$19.620	4.49%
Connecticut Energy Corp.	3/3/1994	900,000	$20.125	$19.220	4.71%
Mobile Gas Service Corp.	9/14/1994	400,000	$22.000	$20.300	8.37%
Northwest Natural Gas	2/15/1995	1,000,000	$29.750	$28.590	4.06%
MCN Corp.	3/14/1995	5,000,000	$17.875	$17.210	3.86%
Piedmont Natural Gas	3/20/1995	1,500,000	$20.000	$19.140	4.49%
Laclede Gas	5/15/1995	1,550,000	$19.000	$18.120	4.86%
United Cities	6/8/1995	1,200,000	$14.500	$13.880	4.47%
Atlanta Gas Light	6/12/1995	1,300,000	$33.625	$32.510	3.43%
WICOR, INC.	12/5/1995	1,100,000	$31.875	$30.630	4.06%
Connecticut Natural Gas	6/5/1996	640,000	$23.250	$22.190	4.78%
Delta Natural Gas	7/15/1996	350,000	$16.000	$15.070	6.17%
Tejas Gas	7/22/1996	3,075,000	$35.000	$33.420	4.73%
KN Energy	7/31/1996	3,100,000	$32.250	$31.010	4.00%
Cascade Natural Gas	8/13/1996	1,350,000	$15.250	$14.450	5.54%
Energen	1/17/1997	1,500,000	$29.500	$28.390	3.91%
KCS Energy	1/29/1997	3,000,000	$39.000	$36.910	5.66%
Energen	9/18/1997	1,200,000	$35.500	$34.160	3.92%
COHO Energy, Inc.,	9/29/1997	8,585,000	$10.500	$9.870	6.38%
Fall River Gas Co.	10/30/1997	340,000	$13.250	$12.060	9.87%
Connecticut Energy Corp.	11/12/1997	900,000	$24.250	$23.170	4.66%
Roanoke Gas Co.	2/22/1998	166,000	$20.000	$18.668	7.13%
KN Energy	3/4/1998	11,000,000	$52.000	$49.902	4.20%
Enron Corp.	5/5/1998	15,000,000	$50.000	$48.466	3.17%
Washington Gas Light	12/12/1998	2,000,000	$25.063	$24.089	4.04%
Laclede Gas	5/5/1999	1,100,000	$20.188	$19.252	4.86%
Semco	6/12/2000	9,000,000	$10.000	$9.600	4.17%
WGL Holdings	6/26/2001	1,790,000	$26.730	$25.804	3.59%
Average 1992-2001					**4.85%**
				Selected Flotation Costs for Cost of Equity	**4.75%**

Sources: EBASCO, *Analysis of Public Utility Financing* and *Public Utility Financing Tracker*

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-___

Direct Testimony
of
Craig A. Keller, CPA

Q. Would you please state your name, business address and position?

A. Yes. My name is Craig A. Keller and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Vice President, Controller and Chief Accounting Officer (CAO) for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties?

A. As Vice President, Controller and Chief Accounting Officer, I am responsible for providing overall direction and management of the accounting, information systems and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and obtained a Masters degree in Business Administration from the University of Montana. I am a certified public accountant and a member of the AICPA and the North Dakota Society of Certified Public Accountants. I was employed with Montana-Dakota in 1986 as an Internal Auditor and during my career with the company have held positions of Income Tax Supervisor, Corporate Financial Planning

Manager, and General Accounting Manager.

Q. Are you familiar with the territory served by Montana-Dakota and the facilities of the Company utilized in providing gas service?

A. Yes, I am.

Q. What is the purpose of your testimony in this proceeding?

A. I am responsible for presenting Statement A, Statement B, and Statement F.

Q. Would you describe Statement A, Statement B and Statement F?

A. Statement A, pages 1 and 2 show Montana-Dakota's balance sheet as of December 31, 2000 and December 31, 2001. Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2001. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Statement F shows the gas utility capital structure of Montana-Dakota for the twelve months ended December 31, 2001 and the projected average capital structure for 2002 and 2003. Statement F includes the associated costs of debt, preferred stock and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 11.044%. The basis for the requested 13.25% return on common equity contained within the overall requested rate of return is supported by the testimony of Dr. J. Stephen Gaske.

Q. Were these statements and the data contained therein prepared by you or under your supervision?

A. Yes, they were.

Q. Are they true to the best of your knowledge and belief?

A. Yes, they are.

Q. Would you please explain Statement F?

A. Pages 1 through 3 of Statement F summarize the actual average gas utility capital structure at December 31, 2001 and the projected average capital structure and the related utility costs of capital for 2002 and 2003. As shown on page 3, the components of the 2003 projected overall annual rate of return, which are used by Ms. Mulkern to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	3.951%
Preferred Stock	0.244%
Common Equity	6.849%
Required Rate of Return	11.044%

The debt costs reflected on Statement F, pages 1 through 3 represent the actual weighted embedded costs of the long-term debt at December 31, 2001 and that projected to be outstanding at December 31, 2002 and December 31, 2003 and are supported by Statement F, Schedule F-1. In calculating the debt costs the "Yield-to-Maturity" method (also referred to as the Internal Rate of Return ("IRR") method) is used to determine the total cost for each respective debt issue as presented on Schedule F-1, page 4 of 7. The yield-to-maturity calculation of each debt issue outstanding gives consideration to the stated rates of interest being paid on such debt, the timing of the interest payments, related issuance expenses, underwriters' commissions and indenture revision costs, the discount or premium realized upon issuance and the

amortization of losses on bond redemption transactions.

Statement F, Schedule F-2, supports the cost of Montana-Dakota's preferred stock capital, representing the weighted cost of the issues at December 31, 2001 and projected to be outstanding at December 31, 2002 and December 31, 2003.

Statement F, Schedule F-3, supports the Company's average utility common equity balance at December 31, 2001, and the projected average balances for 2002 and 2003.

Q. What does Statement F, Schedule F-1 show?

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2001 and average cost of debt. Page 2 shows the projected average long-term debt and costs for 2002 and page 3 shows the same information for projected 2003. Page 4 shows the cost and the debt balance by issue at December 31, 2001.

Q. How did you derive the projected cost of debt as for 2002 and 2003?

A. The projected cost of debt for 2002 and 2003 is based upon the yield to maturity of each debt issue outstanding.

Q. Would you please describe Statement F, Schedule F-1, pages 5 through 7 and explain the amortization method utilized?

A. Pages 5 through 7 reflect the detail by issue of the annual amortization of net discounts (losses) on advance purchases of debt that are necessary to meet sinking fund requirements. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues, the same calculation as is used by the Company for accounting purposes.

Q. What does Statement F, Schedule F-2 show?

A. Pages 1 through 3 present the preferred stock balances at December 31, 2001 and the projected average balances for 2002 and 2003. The anticipated weighted average cost of preferred stock is also shown. Page 4 sets forth the various preferred stock issues outstanding at December 31, 2001.

Q. What does Statement F, Schedule F-3 show?

A. Pages 1 through 3 present the common equity balances at December 31, 2001 and the projected average balances for 2002 and 2003 including the projected changes in the balances each year.

Q. What does Statement F, Schedule F-4 show?

A. Page 1 indicates that, during the five-year period preceding December 31, 2001, MDU Resources Group, Inc. issued 17.2 million additional shares of common stock in connection with a three-for-two stock split. Also during that period, the number of authorized shares of common stock was increased from 75 million at a par value of $3.33 to 150 million with a par value of $1.00.

Q. Would you please describe Statement F, Schedule F-5?

A. This schedule presents various financial and market data relative to the Company's common stock for the years 1997 through 2001, and for each month of the twelve month period ended December 31, 2001.

Q. Would you please describe Statement F, Schedule F-6?

A. This schedule shows that there was no reacquisition activity for bonds and a summary of scheduled retirements of preferred stock for the 18 months ended December 31, 2001.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-

Direct Testimony
of
Rita A. Mulkern

Q. Would you please state your name and business address?

A. Yes. My name is Rita A. Mulkern and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Analysis Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

A. Would you please describe your duties as Regulatory Analysis Manager?

A. I am responsible for the preparation of cost of service studies, fuel cost adjustments, purchased gas cost adjustments and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

Q. Would you please describe your education and professional background?

A. I graduated from North Dakota State University in 1981 with a Bachelor of Arts degree with majors in Economics and Business Administration and a minor in Statistics. I joined Montana-Dakota in July 1981 as a Regulatory Statistician, became Cost of Service Supervisor in 1986 and assumed my current position in 1999.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes, I have presented testimony before the Public Service Commissions of Montana, North Dakota, and Wyoming and the South Dakota Public Utilities Commission.

Q. Are you familiar with the territory served by Montana-Dakota and the facilities of the Company utilized in providing gas service?

A. Yes, I am.

Q. Are you familiar with the books and records of Montana-Dakota and the manner in which they are kept?

A. Yes. Montana-Dakota's books and records are kept in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the per books cost of service for the twelve months ended December 31, 2001, the projected cost of service for 2002 and 2003 and the calculation of the revenue deficiency.

Q. What statements, schedules and exhibits are you sponsoring?

A. I am sponsoring Statements C through E, Statements G through L, Statements N and O and Exhibit No.___(RAM-1)

Q. Were these statements and exhibits prepared by you or under your direct supervision?

A. Yes, they were.

Q. What were the results of North Dakota gas operations for 2001?

A. Statement L, pages 1 and 2 show the per books income statement and rate base for total Company and North Dakota gas operations. The details for each line item, i.e. sales revenue, other revenue, plant in service, etc., are included in the applicable Statement listed.

Q. How was the per books cost of service allocated to North Dakota?

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense and rate base to the jurisdictions as part of the regular accounting process on a monthly basis, resulting in jurisdictional results on an ongoing basis. The allocation methods and procedures are the same as have previously been adopted by this Commission and are based on the principle of assigning and/or allocating costs to the cost causer. The total Company and North Dakota information included in the Statements is from the books and records of the Company.

Q. What test period are you using to determine the revenue requirement?

A. The revenue requirement is based on a projected average 2003 test year. Since the rates will become effective in late 2002, an average 2003 cost of service will best match the cost and customer levels at the time that the rates will go into effect. The rates from this proceeding will be in effect for 2003 and the closer that revenues, expenses and rate base reflect levels to be experienced in 2003, the better the match will be and the better opportunity Montana-Dakota will have to earn its authorized return. Montana-Dakota is using a future test year in accordance with North Dakota Century Code §49-05-04.1.

Q. Would you describe the development of the projected cost of service for 2002 and 2003?

A. The projected 2002 and 2003 cost of service is presented in Statement N, which contains all of the schedules supporting the income statement on page 1, and Statement O, which contains all of the schedules supporting the rate base on page 1. The revenues and expenses reflect the annual level that will be experienced when the new rates become effective. Likewise, the rate base reflects average 2002 and 2003 plant and related balances.

Q. Would you describe the development of the projected revenues and expenses contained in Statement N?

A. Sales and transportation revenues are shown on page 2 and reflect projected sales and transportation volumes for all classes. The projected residential and firm general service sales volumes for 2002 and 2003 were based on actual historical data and forecasted for 2002 and 2003 using the Company's gas supply/forecasting model SENDOUT™. This model forecasts consumption based on the number of customers and the non-heating and weather normalized heating use per customer. The projections incorporate customer growth, ongoing conservation and normal weather. The number of firm customers is projected to grow at approximately 0.9 percent per year and the projected volumes reflect continuing conservation of 1.0% per year. The projected firm revenues were calculated based on the projected volumes and number of customers using the currently effective rates inclusive of the PGA effective

March 1, 2002, exclusive of the surcharge adjustment and margin sharing adjustment.

The sales and transportation volumes for the U.S. Air Force, small interruptible and large interruptible classes were projected on a customer-by-customer basis and the revenues were calculated using current rates.

Miscellaneous revenues, shown on page 3, are projected to remain at the 2001 level.

Q. Would you describe the development of the operation and maintenance expenses?

A. Yes. Pages 4 and 5 of Statement N summarize the projected 2002 and 2003 operation and maintenance (O&M) expenses, with the details provided on pages 6 through 14. The cost of gas, shown on page 6, uses the projected sales volumes, adjusted for losses, and current gas costs effective March 1, 2002. The loss factor of 0.45% was calculated by comparing the gas volumes delivered into the town border stations in North Dakota to the gas volumes sold and dk transported to customers on a billing cycle basis for a twelve-month period ending June 2001. The difference between deliveries at the town border station and deliveries to customers (sales) is the lost and unaccounted for gas, which is then expressed as a percentage of total deliveries.

Labor expense is shown on page 7, with actual labor expense for the twelve months ended December 31, 2001 as the starting point. The labor expense for 2002 and 2003 was developed by applying the projected percentage increase in total Company labor costs to the 2001

per books North Dakota labor expense. The projected labor costs were based on the labor amounts budgeted for 2002, adjusted to reflect a three year average amount for the bonuses and commissions and amounts to a 3.15 percent increase for 2002. A labor increase of 3% was applied to the 2002 labor expense to arrive at the 2003 labor expense.

Benefits expense consists of medical/dental insurance, pension expense, the Supplemental Income Security Plan (SISP), 401K, post-retirement, workers compensation and other benefits. Each of these items, excluding the other benefits, was projected individually for 2002 using the 2002 budgeted amounts and applying the projected increase to each type of benefit. Benefits expense for 2003 reflects a projected increase by type of benefit. Mr. Espeland discusses the inclusion of the SISP expense in his testimony.

Insurance expense, as shown on page 9, reflects the current insurance level for 2002, which is a 40 percent increase over the 2001 level and a projected 2.75% increase for 2003.

Rate case expense is shown on page 10. The projected 2002 and 2003 level incorporates the projected rate case expenses from this case amortized over a three-year period.

Page 11 shows the projected level of advertising expense for 2002 and 2003. Informational advertising is increased to reflect the reclassification of informational advertising recorded in the incorrect account. Promotional advertising has been eliminated, pursuant to North Dakota Administrative Code (NDAC) §69-09-01-29.

Q. Is the Company requesting the inclusion of institutional advertising in this case?

A. Montana-Dakota is seeking to include institutional advertising that falls within NDAC Section 69-09-01-29 1.e.(7). Section 69-09-01-29 of the NDAC relates to advertising by gas utilities. The rule defines various types of advertising as well as stating which types of advertising are allowable in the cost of service. Part 2 of the rule states that "Any expenditure by the utility for institutional, promotional, or political advertising shall be excluded from operating expenses in the cost of service determination for ratemaking purposes." However, the rules exclude from institutional advertising; at 1.e.(7) "Advertising determined by the Commission to benefit customers and serve the public interest." As a corporate citizen, Montana-Dakota needs to be active in the communities that it serves. Our communities expect nothing less and advertising in the local newspapers, school yearbooks, programs, etc., is a necessary part of being active in the community. This advertising benefits the community and the customers in that community, thus serving the public interest. Another example of this type of advertising is the Community Matters publication, which is included as a supplement in various local newspapers in the state. This supplement contains articles on topics such as gas prices, Montana-Dakota's community involvement and safety related articles. The Community Matters supplement serves to inform customers about what is important to them and to confirm that Montana-

Dakota is a part of the community, which benefits both the customers and their communities.

Q. What other O&M expenses are included in Statement N?

Page 12 reflects the inclusion of contributions to Energy Share of North Dakota (Energy Share). Energy Share fulfills a critical role by assisting customers who do not qualify for other forms of assistance in paying their energy bills. This has a positive effect on arrears and ultimately helps reduce the uncollectible accounts for Montana-Dakota. It also provides a needed service for those who are experiencing difficulty in paying their bills. Energy Share also performs weatherization and repair services, which help energy conservation and assure that customers have safe equipment.

Pages 13 and 14 show the O&M expenses not specifically identifiable or calculated as described above, adjusted for the effects of inflation. A 2.81% inflation factor based on the increase in the consumer price index for 1999-2001 was applied to the expenses not specifically identifiable.

Q. Would you describe the calculation of depreciation expense?

A. Yes. Depreciation expense for projected 2002 and 2003 is shown on page 15 and was calculated using projected plant in service and the depreciation rates obtained from a study by Stone & Webster Management Consultants, Inc., as shown in Statement I. Internal studies for computer equipment, work equipment and transportation equipment

were used. The composite depreciation rates and calculation are shown on Statement O, pages 5 and 6.

Q. Would you describe the calculation of taxes other than income?

A. Yes. Taxes other than income are shown on pages 16 through 19. Ad valorem taxes were calculated using the projected 2002 and 2003 plant in service and applying the effective tax rates based on the 2001 ratio of ad valorem taxes to plant.

Payroll taxes projected for 2002 and 2003 follow labor expense. The ratio of payroll taxes to labor expense for 2001 was calculated and applied to the projected 2002 and 2003 labor expense to determine the projected levels. All other taxes other than income were projected to remain at the 2001 level.

Q. Would you describe the calculation of federal and state income taxes?

A. The current income tax calculation is shown on pages 20 through 22. Interest expense is calculated on the projected rate base using the weighted cost of long term debt from Statement F. The tax deductions on page 22 were individually projected. The tax rate of 39.61% reflects the composite state and federal rate. Deferred income taxes are shown on page 23 and include the full normalization of federal and state deferred income taxes.

Q. Would you please describe the development of the projected rate base for 2002 and 2003?

A. Yes. The rate base was developed as shown in Statement O. Page 1 shows the 2001 actual and projected 2002 and 2003 average rate

base for North Dakota gas operations. Pages 2 and 3 show the projected plant in service for 2002 and 2003. The projected plant was developed by adding the capital budget items for 2002 to the 2001 plant in service balances. Retirements, based on a three-year average of retirements by function, were deducted and the average 2002 balance calculated. The process was repeated for 2003. In addition to the capital budget items for 2003, plant additions also include the cost of new and replacement service lines. As discussed by Mr. Fox, Montana-Dakota is proposing to own the customer service line on all new and replacement lines, which is a change from past practice. It is estimated that there will be approximately 880 new and replacement service lines each year. The acquisition adjustment relates to the Hettinger propane system. Montana-Dakota purchased the system in 1993, and in 1999 rolled the distribution rates for Hettinger together with the natural gas rates. Upon purchase of the system, Montana-Dakota recorded an acquisition adjustment on the books. In this case, Montana-Dakota is proposing to recover the acquisition adjustment over a 34.5 year period.

The accumulated reserve for depreciation was calculated using the reserve balances at December 31, 2001, adding the calculated depreciation expense and deducting retirements based on a three-year average of retirements. The average 2002 balances were then calculated and are shown on pages 4 through 6. The process was repeated to arrive at the average 2003 reserve balances. The accumulated reserve on the acquisition adjustment relates to the propane distribution system in

Hettinger. Montana-Dakota recorded an acquisition adjustment on the books in 1993, but did not begin to amortize the acquisition adjustment at that time. In this case, Montana-Dakota is proposing to recover the acquisition adjustment and has reflected the reserve as if Montana-Dakota had begun to amortize it upon purchase.

Q. How were the working capital items derived?

A. The projected working capital items are shown on pages 7 through 12. Materials and supplies were restated to a thirteen month average balance on page 8 and the propane fuel stocks are restated to a thirteen month balance on page 9.

Prepayments, made up of prepaid insurance and the prepaid tax-free option plan, as shown on page 10, are also restated to a thirteen-month average balance. Projected 2002 starts with the actual balances for January 2002 and projected levels for the remaining months, based on the projected insurance expense for 2002 and 2003.

The unamortized portion of the gas IRP and gas supply analysis costs arising from the ten year amortization of the costs are restated to reflect the current amortization and a thirteen month average and are shown on page 11.

Customer Advances for construction are restated to a thirteen month balance as of December 2001.

The accumulated deferred income tax balances on page 13 were derived by adding the deferred income taxes related to property for 2002

and 2003 to the 2001 balance from Statement N, page 31 and calculating average balances.

The accumulated investment tax credit balances were derived by subtracting the projected amortization for 2002 and 2003 from the 2001 balance and calculating average balances.

Q. What does Exhibit No.____(RAM-1) show?

A. Exhibit No.____(RAM-1), page 1, which is identical to Statement L, page 4, shows the calculation of the revenue deficiency of $2,840,000 based on the projected 2003 operating income and rate base and using the overall rate of return of 11.044% from Statement F, page 1. Page 2 shows the per books and projected average rate base for 2002 and 2003 and is identical to Statement O, page 1.

Q. Does that complete your testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - NORTH DAKOTA
(000s)

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$67,962	**$2,840**	$70,802
Transportation	900		900
Other	287		287
Total Revenues	69,149	2,840	71,989
Operating Expenses			
Operation and Maintenance			
Cost of Gas	50,072		50,072
Other O&M	14,354		14,354
Total O&M	64,426		64,426
Depreciation	3,261		3,261
Taxes Other Than Income	1,352		1,352
Current Income Taxes	(1,961)	1,125	(836)
Deferred Income Taxes	1,612		1,612
Total Expenses	68,690	1,125	69,815
Operating Income	$459	$1,715	$2,174
Rate Base	$19,681		$19,681
Rate of Return	**2.332%**		**11.044%**

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

		Projected	
	2001	2002	2003
Gas Plant in Service	$68,787	$70,446	$72,793
Accumulated Reserve for Depreciation	44,629	47,021	49,356
Net Gas Plant in Service	24,158	23,425	23,437
CWIP in Service Pending Reclassification	167		
Total Gas Plant in Service	24,325	23,425	23,437
Additions			
Materials and Supplies	402	439	439
Fuel Stock	21	22	22
Prepayments	19	84	84
Other	151	97	44
Total Additions	593	642	589
Total Before Deductions	$24,918	$24,067	$24,026
Deductions			
Accumulated Deferred Income Taxes	$4,297	$4,090	$3,842
Accumulated Investment Tax Credits	290	256	231
Customer Advances	377	272	272
Total Deductions	4,964	4,618	4,345
Total Rate Base	$19,954	$19,449	$19,681

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-___

Direct Testimony
of
Richard A. Espeland

Q. Would you please state your name and business address?

A. Yes, my name is Richard A. Espeland. My business address is 918 East Divide Avenue, Bismarck, North Dakota 58506.

Q. What is your position?

A. I am Vice President—Human Resources for MDU Resources Group, Inc. (MDU Resources).

Q. What are your duties and responsibilities with MDU Resources?

A. I have overall responsibility for the Human Resource functions throughout the corporation. The primary areas include employment, total compensation (general and executive compensation and benefits), training and development, employee relations and employee communications.

Q. Would you please outline your educational and professional background?

A. In 1966, I received a Bachelor of Arts degree from the University of North Dakota in Business Administration with a major in Personnel Management. In 1981, I received a Masters degree from the University of North Dakota in Public Administration.

Upon graduating from college, I spent four years in the U.S. Army. Prior to my employment with MDU Resources I was employed by the City of Grand Forks, the State of North Dakota and North American Coal Corporation, all in the human resources area.

In December 1989, I joined MDU Resources as Human Resource Manager, retaining that position until August 2000 when I was elected Vice President—Human Resources.

I am a member of the Society for Human Resource Management and the Central Dakota Human Resource Association. I have spoken on retirement and employee benefit issues on many occasions at national conferences in Boston, Orlando, Chicago and San Francisco.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Supplemental Income Security Plan (SISP), the cost of which has been included by Company witness Mulkern in the cost of service in this proceeding.

Q. What are your duties and responsibilities relative to the SISP?

A. I am the Plan Administrator assigned the responsibility by the Board of Directors for the management of the plan, plan design, eligibility, interpretation, communication and benefits administration.

Q. Would you briefly describe what the SISP is and what it is designed to do?

A. The SISP is a plan that provides a supplemental pension benefit to key employees. It was designed to provide equitable retirement benefits for key employees and to attract and retain key employees in a number of positions within the Company.

Q. Who are the "key employees" you refer to who are participants in SISP?

A. "Key employees" are officers, directors and senior managers of MDU Resources and Montana-Dakota who have the vision to adequately plan for the future, implement appropriate strategies for the Company and to see how to reduce costs, streamline the organization, and implement new technologies to maintain and increase the efficiencies of the Company with fewer employees while keeping the rates stable and competitive in the industry.

Q. When was the SISP implemented?

A. The SISP was implemented in 1982.

Q. Montana-Dakota, other than in a recent electric proceeding in North Dakota, has not previously sought rate recovery of the SISP. Would you please explain why?

A. Yes. When the SISP was implemented in 1982, it was a visionary plan that was new to the utility industry. It was not common at that time anywhere within the industry. In the intervening years since then, and particularly in the last few years, Supplemental Employee Retirement Plans (SERPs) like Montana-Dakota's SISP have become common practice in utilities and related companies. These types of plans have become necessary due to various changes in federal regulations, social security benefits, and employment practices. Those changes have adversely affected Montana-Dakota's key employees as to potential retirement benefits. Because of those changes, SERPs such as Montana-

Dakota's SISP have become necessary in order to attract, retain, and provide equitable benefits for key employees.

Q. Please describe the various changes in federal regulations that have adversely affected retirement plans for key employees.

A. In the early 1980s, defined benefit pension plans could provide benefits in consideration of up to $225,000 in salary. That limit was reduced in the mid 1980s to $150,000 maximum covered compensation, therefore, reducing the benefit eligibility and pension benefits provided by one-third. This compensation limit has slowly increased to the current $200,000 level, but certainly not at a pace equal to general wage inflation. In addition, the 401(k) Plan regulations limit the employee contribution to $11,000. (The effect is the employee with $50,000 in annual income can contribute 22% of salary while senior executives are generally limited to 10% or less of salary).

Q. What changes in social security benefits have adversely affected key employees?

A. The social security covered wage base, while increasing over the years, has not kept pace with general wage inflation and benefits provided to higher income levels are significantly less than at lower income levels.

Q. How do the overall retirement benefits for employees included in the SISP compare with the retirement benefits for those employees not included in the SISP?

A. When compensation and benefit programs are designed and implemented, they must be looked at in the context of total benefits. To

put the retirement programs in perspective, I have prepared Exhibit No. ___(RAE-1) which reflects the retirement programs available to employees, including SISP. As you will note from the graph, at the lower income levels, the replacement income through retirement programs is about 80 percent. This includes Social Security, the Defined Benefit Pension Plan, and the Company match to employee contributions under the 401(k) Plan. As you move up the income scale, the percentage of income replaced by retirement plans significantly decreases based on retirement plan design requirements and government limitations on retirement plans. The SISP, as a supplemental plan, has been designed to replace some—but not all—of the income that is not replaced by Social Security, the Defined Benefit Pension Plan, and the 401(k) Plan. At the higher income levels only about 50 percent of the annual income is replaced, compared to 80 percent at the lower income levels.

Q. Does the SISP benefit last as long as the other retirement benefits you've noted?

A. No, it does not. The retirement benefits under SISP are payable over 15 years beginning at age 65 and not the remaining lifetime of the individual (which currently is about 20 years after retirement). Social Security, the Defined Benefit Pension, and the 401(k) Plan income projections meanwhile cover a retired employee's lifetime.

Q. Should the costs of Montana-Dakota's SISP be included in rates?

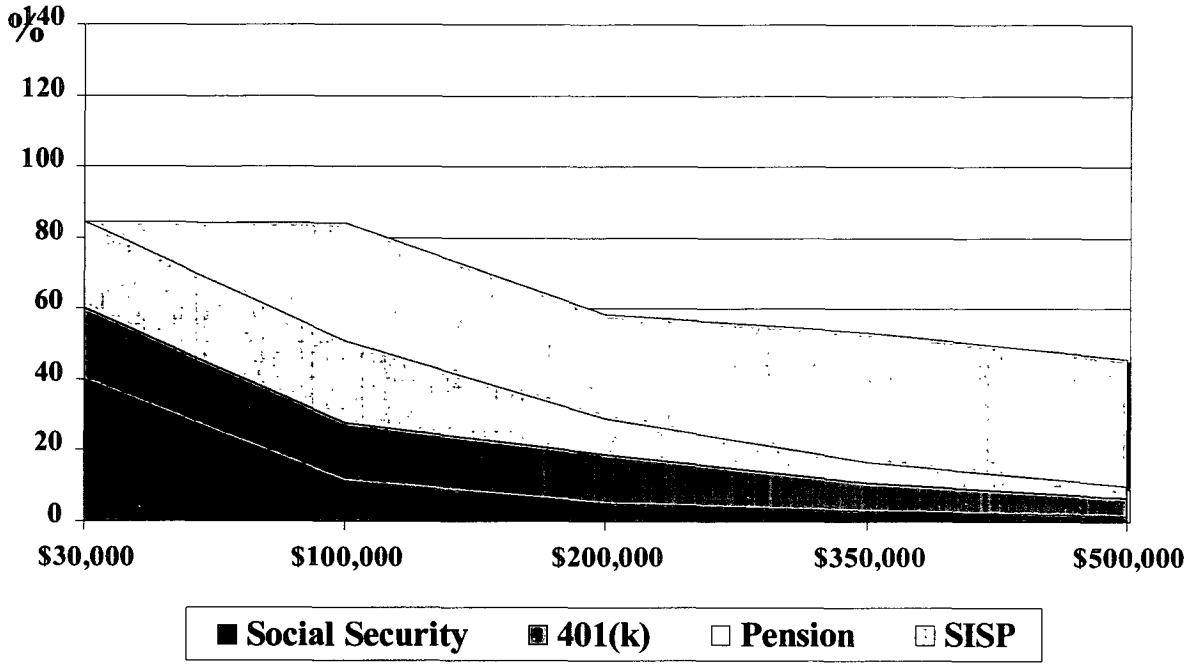
A. Yes, they should be. The SISP is a common type of benefit provided in today's business environment. The combined replacement

income from all retirement plans when taken together is equitable, reasonable and justifiable. The SISP recognizes the contributions of key employees whose abilities and vision have enabled Montana-Dakota to streamline operations, reduce costs and employee numbers, implement new technologies and, most importantly to the ratepayer, to keep Montana-Dakota's rates competitive.

Q. Does this complete your direct testimony?

A. Yes, it does.

% Retirement Replacement Income



Case No._____

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Direct Testimony

of

Russell A. Feingold

on behalf of

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.

April, 2002

Case No._____

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DIRECT TESTIMONY OF RUSSELL A. FEINGOLD

Background And Qualifications

Q. Please state your name and business address.

A. My name is Russell A. Feingold and my business address is 200 Wheeler Road, Suite 400, Burlington, Massachusetts 01803. I am employed by Navigant Consulting, Inc. ("NCI") as a Managing Director and lead its Regulation & Litigation Support Practice. I have been employed by NCI since January 1997.

Q. Please describe in more detail the business activities of NCI.

A. NCI has served the electric and natural gas industries since 1983. We offer a wide range of consulting services related to information technology, process/operations management, business strategy development, and marketing and sales designed to assist our clients in a business environment of changing regulation, increased competition and evolving technology. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide

variety of client assignments. NCI has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 27 years of experience in the utility industry, the last 24 years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. I have prepared and presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and several state and provincial regulatory commissions and have spoken widely on issues and activities dealing with the pricing and marketing of gas and electric utility services.

Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in Appendix A to my testimony.

Q. Have you previously testified on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company"), a Division of MDU Resources Group, Inc.?

A. Yes, I have. I previously testified on behalf of Montana-Dakota before the Montana Public Service Commission in Docket Nos. 87.12.77 and 88.11.53 on the subjects of gas rate design and gas marginal cost analyses.

Purpose

Q. For what purpose has Montana-Dakota retained NCI?

A. NCI has been retained by Montana-Dakota as a consultant in the area of utility rate design and related regulatory matters for its gas operations.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to address certain gas rate design concepts that the Company has evaluated in formulating its rate proposal in this proceeding. Specifically, I will discuss the conceptual underpinnings and industry-wide trends associated with the Company's proposal to enhance the recovery of its gas distribution margin through rate design. In addition, I will provide an overview and analysis of an alternative ratemaking mechanism that

Montana-Dakota could apply to its heat sensitive classes of service.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

- Exhibit No. __ (RAF-1), Survey of Monthly Customer Charges of North American Gas Distribution Utilities
- Exhibit No. __ (RAF-2), Distribution Delivery Stabilization Mechanism

Enhanced Margin Recovery Through Rate Design

Q. Why has Montana-Dakota chosen to propose certain rate design changes that will enhance the recovery of its authorized level of distribution margin?

A. The Company has chosen to address this issue because it has been unable historically to recover its Commission authorized level of distribution margin due to the significant portions of fixed costs included in the volumetric portions of its gas rate structure. As I will discuss later in my testimony, this condition is not unique to Montana-Dakota and is, in fact, quite commonplace in the gas distribution segment of the energy industry.

Q. Do the Cost of Service Study ("COSS") results presented by the Company's witness, Ms. Tamie Aberle, provide guidance in establishing the appropriate rate structure within each rate class?

A. Yes. The classified costs, as allocated to each class of service within the Company's COSS, provide useful cost information in determining the level of customer, demand and commodity charges.

Q. Please explain how the classified costs from the Cost of Service Study presented by Ms. Aberle can be used for rate design purposes.

A. If the classified costs presented by Ms. Aberle in Statement M were used to set three-part rates (Customer, Demand and Commodity), the Company's operating expenses and return on investment in its non-gas revenue requirement would be fully recovered from its customers. The use of three part rates is becoming more widely accepted as the unbundling of utility services continues to evolve and the sale of the gas commodity in an increasingly competitive market is distinguishable from utility delivery service. The unit costs from the Company's COSS provide useful information for the design of portions of its tariff services, in particular for establishing cost-based fixed charges for customer related costs. The unit costs also can be used to design demand charges where either demand metering is available or algorithm-based billing demands for its customers can be determined. Demand based rates provide for a unit charge based upon the maximum demand

imposed by a customer on the utility's gas system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service.

Q. Please describe other considerations or criteria that should be used in the design of utility rates.

A. Utility rate design should recognize that rates must be just and reasonable and not cause undue discrimination. Thus, customer impact considerations must be factored into the rate design process. Market conditions within the utility service territory with respect to the general economic environment and competitive fuel prices, where appropriate, should be reviewed. Another important consideration is the financial stability of the utility. Toward this goal, it is generally an unsound ratemaking practice to recover a substantial portion of fixed costs, such as customer related costs which bear no relationship to customer consumption patterns, in the volumetric portion of the rate structure. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of gas can be extremely sensitive to the vagaries of weather patterns and changing consumption characteristics. Moreover, recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well reasoned energy consumption decisions. Ultimately, Montana-Dakota must establish a reasonable balance between the various cost guidelines and the other

aforementioned criteria in the process of designing rates.

Q. Do the Company's proposed rate schedules reflect increases to its existing monthly service charges?

A. Yes. The Company's schedule of proposed rates includes an increase to the level of the existing residential monthly basic service charge from $6.50 to $11.70. In addition, the firm general service classes include an increase in their monthly basic service charges from $8.50 to $24.00 for small meters (less than 500 cu. ft. per hour) and from $17.00 to $51.00 for large meters. As discussed by Ms. Aberle, the proposed charges are stated on a daily basis.

Q. Do increased fixed charges such as those proposed by the Company provide any benefits to customers?

A. Yes. An increase in the fixed charge component of the rate structure has the effect of reducing the impact of weather variances on customers' bills. By increasing the basic service charge, the usage or volumetric charge is reduced, resulting in lower customer bills during periods of colder than normal weather and generally adding a measure of stability to the monthly bills of customers throughout the year.

Higher monthly basic service charges help equalize the contribution of each

customer within a class towards recovery of the customer-related costs attributable to that class. The increase in the basic service charge will thus help reduce intra-class subsidies. When the basic service charge does not recover the fixed costs of serving a customer, the higher use customers subsidize the lower use customers.

Furthermore, the pricing practices associated with consumer services have evolved in recent years to be more oriented towards fixed charges, which have been widely embraced by the public. Today's consumer is much more accustomed to paying higher up-front fixed charges in exchange for low, or non-existent, usage charges. For example, basic cable television service carries a flat monthly charge and many internet service providers have restructured their pricing in the form of fixed monthly fees with no additional usage charges. Cellular phone companies offer a multitude of rate plans with an escalating scale of fixed monthly charges in exchange for additional "free" talk time. In addition, rental car companies typically charge a flat daily fee that permits the customer to drive, in some cases, an unlimited number of miles without incurring additional usage charges. Finally, at the federal level, the FERC moved to a straight fixed-variable rate design for interstate pipelines with the issuance of Order No. 636.

Q. Why is the Company proposing to increase these service charge levels?

A. As mentioned earlier in my testimony, the Company utilized the unit costs from

its cost of service study to identify costs related to providing monthly service to customers. The level of customer-related costs for its residential class of customers, as presented in Statement M, is $12.77 per month. The corresponding level of customer costs for the firm general class of customers, as presented in this Statement, averages $37.98 per month over all meter sizes.

Establishing higher monthly basic service charges helps to reduce the intra-class subsidies that exist within a particular rate class. This method of customer cost recovery is preferable to including such costs in the commodity block charges, which has the effect of causing higher use customers to subsidize the lower use customers relative to the customer-related costs they impose on the Company.

The basic service charges provide for recovery of a portion of the Company's fixed customer costs that are incurred solely because of the existence of customers connected to its gas distribution system. These costs, associated with facilities in place to serve customers, regardless of use and expenses such as reading meters and billing, occur regardless of whether gas is consumed and are not related to demands placed on the system. The proposed basic service charge increases will also ensure recovery by the Company of a greater portion of its fixed costs of providing service. Since customer costs are not related to gas usage, they should be recovered to the extent possible through a tariff component that does not depend upon volumetric billing.

Q. In view of the level of customer costs indicated by the Company's cost study, would you please explain the choice of the basic service charge levels that have been proposed?

A. Given the relatively high level of customer costs shown in Statement M as compared to its current level of customer related charges, the Company has chosen to move much closer to full cost of service in setting new customer related charges (basic service charge). In the case of the residential class, the level of customer costs identified in Montana-Dakota's cost of service study is more than twice the current level of its customer-related fixed charge. The proposed basic service charge for the Company's Residential Gas Service (Rate 60) of $11.70 per month ($0.39/day) will address the current gap between this class' customer-related costs and its corresponding unit charge. The Company's proposed levels of basic service charges for the Firm General Gas Service (Rate 70) will also bring this class essentially to its full cost of service.

Q. At these proposed rate levels, would the Company's monthly basic service charges result in substantial recovery of the fixed costs for these classes?

A. Yes. However, there still exists approximately $1.5 million of remaining customer-related costs and $3.3 million of fixed demand-related costs in the residential and firm general service classes, representing approximately 25% of the total fixed costs of the Company, to be recovered through the volumetric

rates for the residential and firm general classes.

Q. Are Montana-Dakota's efforts to improve its distribution margin recovery through increased fixed cost recovery in its fixed monthly charges consistent with the recent actions of other gas distribution companies?

A. Yes. In my opinion, there has been a noticeable recent trend in the gas distribution utility industry to increase monthly fixed charges. The monthly fixed charges are often labeled as customer charges, base charges, or basic service charges. Over the last few years, many gas distribution companies have requested increases to their monthly customer charges, where feasible, based on the results of cost of service studies that indicate gaps between the currently approved customer charges and the corresponding levels of allocated customer costs. As a result, customer charges have been increasing over time, and in some cases, increasing on a disproportionate basis.

The results of a recent informal survey conducted by NCI of North American gas distribution companies confirm these conclusions. Forty-one (41) of the gas distribution companies surveyed had implemented increases to their monthly service charges since 1999. Of the sixty-four (64) companies surveyed, encompassing eighty-one (81) different state or provincial service territories, forty-three (43) respondents had residential monthly service charges greater than or equal to $9.00, with the average monthly service charge for this group equal to

$10.67. The results of the NCI survey are presented in Exhibit No. ___ (RAF-1), Survey of Monthly Customer Charges of North American Gas Distribution Utilities.

Q. **Are there any other factors that should be taken into consideration by this Commission in the establishment of the Company's basic service charges?**

A. Yes, there are. Historically, regulatory commissions have approved residential basic service charges well below the level indicated by cost of service studies. The main reasons for this treatment have appeared to be concerns related to the impact of high basic service charges on low use customers and the desire to encourage conservation through the recovery of more costs in a usage charge. While some may view these reasons as valid rate design considerations, they do not properly take into consideration the Company's substantial investment in fixed costs (e.g., mains, services and meters) necessary to serve a customer, regardless of the customer's gas usage level. Setting the basic service charges below cost results in an improper price signal to customers by recovering these fixed distribution costs in a usage or volumetric charge.

Alternative Distribution Delivery Stabilization Mechanism

Q. **Is the Company proposing a Distribution Delivery Stabilization Mechanism ("DDSM") to adjust rates to its heat sensitive classes of service to reflect**

the actual weather conditions it experiences on an annual basis in comparison to the normal weather it uses to establish base rates?

A. No, not at this time. As presented earlier in my testimony, the Company's preference is to address variability in margin recovery through increased collection of fixed costs through fixed charges. However, an acceptable alternative rate design technique would be to increase monthly fixed charges by some level and implement a DDSM to correct for the over and under collection of distribution delivery revenues, due to weather fluctuations, on an annual basis. The DDSM would apply to the Company's weather sensitive rate classes of residential and firm general service.

Q. Has the Company previously submitted to this Commission a similar adjustment mechanism for the purpose of adjusting rates to its heat sensitive classes of service?

A. Yes, it has. In a July 1992 filing before the North Dakota Public Service Commission ("Commission") in Case No. PU-399-92-616, the Company proposed a Weather Normalization Adjustment Rate 89 ("WNA"). That particular WNA had been designed to adjust each customer's monthly bill on a current or *real-time* basis to reflect what would have been billed had normal weather occurred. The Commission's subsequent denial of the WNA proposal was attributed primarily to the complexity of the WNA, the multiple assumptions

necessary to compute the adjustment, and the confusion it could cause Montana-Dakota's customers in attempting to rationalize the fluctuations in their monthly bills caused by the *real-time* adjustments from the WNA. *[Ref. Commission Order in Case No. PU-399-92-616, dated October 20, 1992]*

However, because of the widely recognized beneficial aspect of an adjustment mechanism in addressing the continued impact of weather variability on the Company's margin recovery, Montana-Dakota management believes that a DDSM based on a more simplified approach is appropriate to discuss as an alternative at this time.

Q. Please discuss the reasons for recommending a DDSM.

A. Because of Montana-Dakota's largely volumetric rate design, as discussed earlier in my testimony, the Company will only recover its Commission authorized level of non-gas fixed costs of providing distribution service if the underlying sales volumes are achieved. Deviations from normal weather, the basis for those underlying sales volumes, result in either over or under recovery of Montana-Dakota's fixed costs. Erratic financial results from the constant over and under recovery of distribution margin can adversely impact Montana-Dakota's outlook in the financial community and, ultimately could increase the Company's financing costs. A DDSM addresses the foregoing adverse conditions. It is based on the premise that normal weather represents the best

estimate of an uncontrollable variable and is a logical method for Montana-Dakota to adjust rates to account for the unpredictability of weather. A deferral type of DDSM would address wide swings in Montana-Dakota's total margin recovery through modest year-to-year adjustments in customers' bills in subsequent periods.

Q. How does a deferral type of DDSM in this case differ from the WNA previously proposed by Montana-Dakota?

A. As mentioned earlier, the WNA was a *real-time* approach to adjusting customer billings on a current month basis for the variations from normal weather conditions. Monthly bills for the Company's heat sensitive classes of service rendered from November 1st through April 30th of each year were subject to adjustment for the WNA. A separate WNA adjustment was determined each month for each service period within a billing cycle and applied to all billings within that service period.

A deferral type of adjustment mechanism is a simplified application that corrects for the over/under collection of revenues due to weather fluctuations throughout the winter heating season. Once a year, following the end of the winter heating season, a true-up calculation would be performed to compare actual weather conditions, as represented by the actual level of annual Heating Degree Days (HDDs), with the level of HDDs under normalized weather conditions. The

Company would utilize the normal level of HDDs established in the instant general rate case. The HDD excess or deficiency for the winter period would be applied to the class-by-class use per customer per HDD, also from the general rate case, and the respective class-by-class delivery service margins. The resulting revenue excess or deficiency would be divided by the projected annual sales volumes for the identified rate classes to determine a surcharge or refund component to be applied as an adjustment to the distribution charge.

Q. Please provide a formulaic representation of the DDSM that you just described.

A. A formulaic representation of the DDSM is as follows:

$$DDSM_i = \frac{R_i\,(DDF_i\,(NDD - ADD)) + (PDDSM_i - ADDSM_i)}{ANU_i}$$

Where:

$DDSM_i$ = Weather normalization dollar amount per dk

i = Applicable rate class subject to the DDSM

R_i = Applicable delivery service rate per dk

DDF_i = Weather sensitive use per customer per degree day

NDD = Normal degree days for the winter service period

ADD = Actual degree days for the winter service period

ANU_i = Average normal use per customer for the prospective twelve month period

$PDDSM_i$ = Projected DDSM revenue from the preceding twelve month period

ADDSMi = Actual DDSM revenue recovered during the preceding twelve month period

The result of the calculation, the DDSM factor, is multiplied by the customer's monthly gas consumption and added to or subtracted from the customer's bills during the twelve-month recovery/refund period, depending on the arithmetic sign of the DDSM.

Q. Can this type of DDSM accommodate any variation in the actual margin revenues collected through the DDSM in a particular year compared to the expected level of margin revenues upon which the previous DDSM factor was derived?

A. Yes, it can. The illustrated DDSM has a true-up feature that will adjust the DDSM factor in any subsequent year to reflect any over-collections or under-collections in the prior year caused by variations in the margin revenues derived through application of the then current DDSM factor to the Company's actual gas volumes.

Q. Have you tested the performance of a deferral type of DDSM on Montana-Dakota's recent experience with weather variability in its North Dakota service territory?

A. Yes. Exhibit No.___(RAF-2), DDSM Analysis, provides an illustration of the operation of the annual adjustment mechanism and the determination of the DDSM. Revenue adjustments were computed that would have occurred had this type of DDSM been in effect during each of the last four complete heating seasons, from 1997 – 1998 to 2000 – 2001.

Q. Why was this time period selected to demonstrate the operation of the DDSM?

A. This time period was chosen because it contained weather extremes, both above and below normal conditions assumed by the Company.

Q. Please describe the results of your analysis.

A. The results of the analysis are shown on Exhibit No.___(RAF-2). This schedule shows the year-to-year impact on the Company's revenues due to the variations in temperature. A negative adjustment of ($293,648) would have occurred at the end of the 2000 – 2001 heating season, due to the 4.8% colder than normal temperatures. By contrast, a positive adjustment of $1,284,142 would have occurred at the conclusion of the 1999 – 2000 heating season resulting from 19.6% warmer than normal temperature conditions. Smaller adjustments would have occurred in the earlier years where there was less deviation from normal temperature conditions.

Q. Have you analyzed how this DDSM would have impacted individual customer bills?

A. Yes. The average annual impact on individual residential customer bills corresponding to the 2000 – 2001 colder than normal heating season would have been a negative adjustment of ($2.42). Likewise, a positive total adjustment to an average residential customer bill of $10.12 would have resulted from the 1999

– 2000 warmer than normal heating season. The annual customer DDSM adjustments are shown in the analysis for the heat sensitive classes. In view of the temperature variations that occurred during the heating seasons examined, the analysis presented in Exhibit No. __ (RAF – 2) confirms what one would expect to result from the operation of the DDSM, had it been in effect during those years.

Q. Mr. Feingold, does that complete your direct testimony?

A. Yes, it does.

RUSSELL A. FEINGOLD

EDUCATION

- Bachelor of Science degree in Electrical Engineering from Washington University, St. Louis.
- Master of Science degree in Financial Management from Polytechnic Institute of New York

PROFESSIONAL EMPLOYMENT

1997 – Present	**Navigant Consulting, Inc.** Managing Director, Regulation & Litigation Support Practice
1990 – 1997	**R.J. Rudden Associates, Inc.** Vice President and Director
1985 – 1990	**Price Waterhouse** Director, Gas Regulatory Services Public Utilities Industry Services Group
1978 – 1985	**Stone & Webster Management Consultants, Inc.** Executive Consultant Regulatory Services Division
1973 – 1978	**Port Authority of New York and New Jersey** Staff Engineer and Utility Rate Specialist Design Engineering Division

PRESENTATION OF EXPERT TESTIMONY

- Federal Energy Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Montana Public Service Commission
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities
- New York Public Service Commission
- Ohio Public Utilities Commission
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Quebec Natural Gas Board (Canada)
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission

EDUCATIONAL AND TRAINING ACTIVITIES

- Chairman, Rate Training Subcommittee, Rate and Strategic Issues Committee of the American Gas Association
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison, 1985 – 2001
- Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland - College Park, 1987 –1992
- Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987
- Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987
- Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress)

PUBLICATIONS AND PRESENTATIONS

- "LDC Perspectives on Managing Price Volatility" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2002.
- "Can a California Energy Crisis Occur Elsewhere?" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2001.
- "Downstream Unbundling: Opportunities and Risks," American Gas Association, Rate and Strategic Issues Committee Meeting, April 2000.

- "Form Follows Function: Which Corporate Strategy Will Predominate in the New Millennium?" American Gas Association 1999 Workshop on Regulation and Business Strategy for Utilities in the New Millennium, August 1999
- "Total Energy Providers: Key Structural and Regulatory Issues," American Gas Association, Rate and Strategic Issues Committee Meeting, April 1999.
- "The Gas Industry: A View of the Next Decade," National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Accounts, 1998 Fall Meeting, September 1998.
- "Regulatory Responses to the Changing Gas Industry," Canadian Gas Association, 1998 Corporate Challenges Conference, September 1998
- "Trends in Performance-Based Pricing," American Gas Association Financial Analysts Conference, May 1998.
- "Unbundling – An Opportunity or Threat for Customer Care?" presented at the American Gas Association/Edison Electric Institute Customer Services Conference and Exposition, May 1998.
- "Experiences in Electric and Gas Unbundling," presented at the 1997 Indiana Energy Conference, December 1997.
- "Asset and Resource Migration Strategies," presented at the Strategic Marketing For The New Marketplace Conference sponsored by Electric Utility Consultants, Inc. and Metzler & Associates, November 1997.
- "The Status of Unbundling in the Gas Industry," presented at the American Gas Association Finance Committee, March 1997.
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- "State Regulatory Update," presented at the American Gas Association - Financial Forum, May 1995.
- "Gas Pricing Strategies and Related Rate Considerations," presented before the Rate Committee of the American Gas Association, April 1995.
- "Avoided Cost Concepts and Management Considerations," presented before the Workshop on Avoided Costs in a Post-636 Industry, sponsored by the Gas

Research Institute and Wisconsin Center for Demand-Side Research, June 1994.

- "DSM Program Selection Under Order No. 636: Effect of Changing Gas Avoided Costs," presented before the NARUC-DOE Fifth National Integrated Resource Planning Conference, Kalispell, MT, May 1994.
- "A Review of Recent Gas IRP Activities," presented before the Rate Committee of the American Gas Association, March 1994.
- Seminar organizer and co-moderator at the American Gas Association seminar, "The Statue of Integrated Resource Planning," December 1993.
- "Industry Restructuring Issues for LDCs, presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland, 1993-1996.
- "Acquiring and Using Gas Storage Services," presented before the 8th Cogeneration and Independent Power Congress and Natural Gas Purchasing '93, June 1993.
- "Capitalizing on the New Relationships Arising Between the Various Industry Segments: Understanding How You Can Play in Today's Market," presented before the Institute of Gas Technology's Natural Gas Markets and Marketing Conference, February 1993.
- "The Level Playing Field for Fuel Substitution (or, the Quest for the Holy Grail)," presented before the 4th Natural Gas Industry Forum - Integrated Resource Planning: The Contribution of Natural Gas, October 1992.
- "Key Methodological Considerations in Developing Gas Long-Run Avoided Costs," presented before the NARUC-DOE Fourth National Integrated Resource Planning Conference, September 1992.
- "Mega-NOPR Impacts on Transportation Arrangements for IPPs," co-presented before the 7th Cogeneration and Independent Power Congress and Natural Gas Purchasing '92, June 1992.
- "Cost Allocation in Utility Rate Proceedings," presented before the Ohio State Bar Association - Annual Convention, May 1992.

- "The Long and the Short of LRACs," presented before the Natural Gas Least-Cost Planning Conference April 1992, sponsored by Washington Gas Company and the District of Columbia Energy office.
- Seminar organizer and moderator at the American Gas Association seminar, "Integrated Resource Planning: A Primer," December 1991.
- Session organizer and moderator on integrated resource planning issues at the American Gas Association Annual Conference, October 1991.
- "Strategic Perspectives on the Rate Design Process," presented before the Executive Enterprises, Inc. conference, "Natural Gas Pricing and Rate Design in the 1990s," September 1990.
- "Distribution Company Transportation Rates," presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland 1987-1992.
- "Design of Distribution Company Gas Rates," presented before the American Gas Association - Gas Rate Fundamentals Course, University of Wisconsin, 1985-1998.
- Seminar organizer, speaker and panel moderator at the American Gas Association seminar, "Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing," 1988-1990.
- "Local Distribution Company Bypass - Issues and Industry Responses," (Co-author) June 1989.
- "So You Think You Know Your Customers!," presented before the American Gas Association–Annual Marketing Conference, April 1990.
- "Gas Transportation Rate Considerations - A Review of Gas Transportation Practices Based on the Results of the A.G.A. Annual Pricing Strategies Survey," presented before the Rate Committee of the American Gas Association, April 1985-1991.
- "Market-Based Pricing Strategies - Targeted Rates to Meet Competition," presented before the American Gas Association Annual Marketing Conference, March 1989.

- "Gas Rate Restructuring Issues - Targeted Prices to Meet Competition," presented before the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.
- "Gas Transportation Rates - An Integral Part of a Competitive Marketplace," *American Gas Association, Financial Quarterly Review*, Summer 1987.
- "Gas Distributor Rate Design Responses to the Competitive Fuel Situation," *American Gas Association, Financial Quarterly Review*, October 1983.
- "Demand-Commodity Rates: A Second Best Response to the Competitive Fuel Situation," presented before the American Gas Association, Ratemaking Options Forum, September 1983.
- Cofounder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.
- "Current Rate and Regulatory Issues," presented before the National Fuel Gas Regulatory Seminar, July 1986.

AFFILIATIONS AND HONORS

- Financial Associate Member, American Gas Association
- Member, Rate and Strategic Issues Committee of the American Gas Association
- Member, Energy Bar Association
- Member, Institute of Electrical and Electronic Engineers
- Listed in Who's Who of Emerging Leaders in America, 1989-1992

(Current as of March 2002)

Montana-Dakota Utilities Company
Survey of Monthly Customer Charges
of North American Gas Distribution Utilities

	Company		Current Customer Charge	Current Charge Effective		Company		Current Customer Charge	Current Charge Effective
	(A)		(B)	(C)		(D)		(E)	(F)
1	Ameren (IL)		$ 9.50	Feb-99	42	MidAm (IL)	$	9.00	Jul-00
2	Ameren (MO)		$ 9.00	Nov-00	43	Missouri Gas	$	10.05	Aug-01
3	Apollo Gas (PA)		$ 9.00	N/A	44	Nashville Gas Division	$	8.00	Dec-00
4	Arkansas Oklahoma Gas		$ 9.00	Sep-97	45	New Jersey Natural Gas Co.	$	6.54	Dec-00
5	ArkLa (TX)		$ 10.70	N/A	46	NFG (NY)	$	14.18	Oct-97
6	ATCO Gas North		$ 7.68	Jan-01	47	NFG (PA)	$	11.09	May-93
7	ATCO Gas South		$ 8.41	Jan-01	48	Niagara Mohawk	$	14.55	Aug-00
8	Atlanta Gas Light		$ 9.76	N/A	49	NIPSCO	$	6.36	Dec-00
9	Atlas Gas Utilities		$ 9.06	Jan-01	50	Northern Utilities (ME)	$	9.92	N/A
10	Avista Utilities		$ 5.00	Dec-00	51	Northern Utilities Natural (NH)	$	6.91	Dec-00
11	Baltimore Gas & Electric		$ 12.25	Jun-00	52	Northwest Natural (Rate 2) (WA)	$	4.00	Nov-00
12	Bay Stae Gas (MA)		$ 7.47	Dec-00	53	Northwest Natural (Rate 24) (WA)	$	4.00	Nov-00
13	Berkshire Gas (MA)		$ 10.50	Feb-02	54	Northwest Natural (OR)	$	5.00	Dec-00
14	Boerne Utilities (TX)		$ 11.00	N/A	55	NYSEG (NY)	$	14.00	N/A
15	Boston Gas Company		$ 9.98	N/A	56	Ohio Valley (OH)	$	11.19	Nov-95
16	Centra Gas, (MB)		$ 6.47	Nov-00	57	Peoples Gas (Non-West Fla Region)	$	7.00	Nov-00
17	Central IL Pub. Serv.		$ 9.50	Feb-99	58	PG Energy (PA)	$	11.25	Jan-01
18	Central Ill Light & Power		$ 9.85	Jun-97	59	PNG- West (BC)	$	6.95	Jan-01
19	Cheyenne Light, Fuel & Power		$ 9.00	Aug-00	60	PNG (NE) Ltd. (Dawson Creek)	$	4.53	Jan-01
20	CILCO (IL)		$ 9.85	N/A	61	PNG (NE) Ltd. (Tumbler Ridge)	$	5.50	Jan-01
21	Citizens Gas & Coke Utility (IN)		$ 9.00	N/A	62	Providence Gas Company	$	8.00	Jan-96
22	Columbia Gas (MD)		$ 9.25	Apr-00	63	Public Service Co (NM)	$	9.00	Oct-00
23	Columbia Gas (PN)		$ 10.81	Oct-00	64	Puget Sound	$	4.46	Jan-01
24	Columbia Gas (PA)		$ 11.35	N/A	65	Reliant Energy (MS)	$	9.30	N/A
25	Columbia Gas (VA)		$ 12.25	N/A	66	SaskEnergy, SK (Farm)	$	7.47	Dec-00
26	Con Ed (NY)		$ 11.82	Dec-98	67	SaskEnergy, SK (Residential)	$	6.79	Dec-00
27	Consumers Energy Co. (MI)		$ 6.50	Mar-00	68	South Carolina Elect & Gas	$	3.00	Nov-00
28	Delta Natural Gas Co. (KY)		$ 8.00	Nov-00	69	Southern California Gas	$	10.00	Dec-98
29	Dominion Peoples (PA)		$ 11.00	Mar-00	70	Southwest Gas Corp. (North)	$	6.00	Jan-01
30	Enbridege Consumers (On)		$ 6.47	Oct-00	71	Southwest Gas Corp. (South)	$	6.00	Jan-01
31	Equitable (PA)		$ 11.65	Oct-97	72	UGI (PA)	$	8.55	Aug-95
32	Gaz Metropolitain (PQ)	[1]	$ 6.03	Oct-99	73	Union Gas (ON) (Eastern)	$	6.47	Oct-00
33	Illinois Gas		$ 9.55	Oct-98	74	Union Gas (ON) (Fort Frances)	$	5.82	Oct-00
34	Illinois Power		$ 9.95	Jan-94	75	Union Gas (ON) (Northern)	$	6.47	Oct-00
35	Indiana Gas		$ 9.00	N/A	76	Union Gas (ON) (S. Western)	$	4.85	Oct-00
36	Intermountain Gas (Apr-Nov)	[2]	$ 2.50	Dec-00	77	Union Gas (ON) (Western)	$	6.47	Oct-00
37	Intermountain Gas (Dec-Mar)	[2]	$ 6.50	Dec-00	78	United Cities (IL)	$	9.90	Oct-00
38	KeySpan Energy (NH)		$ 7.89	Dec-00	79	United Cities (VA)	$	6.00	Mar-01
39	Keyspan (NY)		$ 21.16	Oct-01	80	VA Natural Gas	$	9.78	N/A
40	Laclede Gas (MO)		$ 12.00	Sep-96	81	Valley Gas Company (RI)	$	5.60	Jan-95
41	MidAm (IA)		$ 9.00	May-99	82	Yankee Gas (CT)	$	8.75	N/A

[1] Charge stated as a daily charge of 0.19832. For the purpose of this exhibit it has been multiplied by 30.4 (average number of days in a month)
[2] Charges are seasonally differentiated and apply to the same jurisdiction.

Customer Charge Statistics

Mean	$	8.58
Median	$	9.00
Mode	$	9.00
Range	$	18.66
Minimum	$	2.50
Maximum	$	21.16
Count		82

Average of Charges Greater than or Equal to $9.00 =	$	10.67

Montana-Dakota Utilities Co.
Distribution Delivery Stabilization Mechanism Analysis

	Heating Use			Firm	Total	Total Firm	Adjustment
	Actual	Normal	Residential	General	DDSM	Sales [1]	Per Dk
1997	7,558,423	8,453,772	$439,720	$277,552	$717,272	13,521,235	$0.053
1998	7,733,853	8,510,614	365,317	230,002	595,319	14,091,817	$0.042
1999	7,120,518	8,851,055	788,756	495,386	1,284,142	13,973,984	$0.092
2000	8,826,286	8,430,475	(179,804)	(113,844)	(293,648)	13,092,758	($0.022)
Average Adjustment					$2,303,085	54,679,794	$0.042

Customer Bill Impact of DDSM:		Residential	Firm General	Firm General
	Annual Usage (Dk)	Small Meter 110	Small Meter 300	Large Meter 900
1997	**Annual Impact**	$5.83	$15.90	$47.70
1998		$4.62	$12.60	$37.80
1999		$10.12	$27.60	$82.80
2000		($2.42)	($6.60)	($19.80)
Average Adjustment		$4.62	$12.60	$37.80

[1] Adjustment is based on subsequent year's normalized sales.

Case No. _____
Exhibit No. ___ (RAF-2)
Page 1 of 1

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-_____

Direct Testimony
of
Tamie A. Aberle

Q. Would you please state your name and business address?

A. Yes. My name is Tamie A. Aberle, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Pricing & Tariff Manager in the Regulatory Affairs Department of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your responsibilities as the Pricing & Tariff Manager?

A. My responsibilities include the preparation of rate design and miscellaneous tariff revision filings to ensure that the applicable revenue requirements are properly recovered from various customer classes via applicable rate forms. I also administer utility tariffs and rules and regulations effective in each of the jurisdictions in which Montana-Dakota provides utility service.

Q. Would you please outline your educational and professional background?

A. I graduated from Moorhead State University, Moorhead, Minnesota in 1982 with a Bachelor of Science degree in Accounting. I began my career with Montana-Dakota in 1983 in the Regulatory Affairs Department, I was promoted to Rate Administration Supervisor in 1990 and achieved

my present position in May 1999.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission and the Montana Public Service Commission and I have filed testimony with the South Dakota Public Utilities Commission and the Wyoming Public Service Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the results of the class cost of service study and to address the effect of the proposed revenue requirement, as identified by Ms. Mulkern in her direct testimony, on each of the Company's gas rates, including how the distribution of the revenue requirement was made among the various classes of customers served. In addition, my testimony will discuss the extent to which Montana-Dakota is proposing changes in rate design and/or tariff conditions.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Statement M and Exhibit No. ____ (TAA-1) through Exhibit No. ____ (TAA-3).

Q. Were they prepared by you or under your supervision and direction?

A. Yes, they were.

Q. Are they true and correct to the best of your knowledge and belief?

A. Yes, they are.

Q. Do you also sponsor the proposed rate schedules appended to the Application in this proceeding?

A. Yes, I do.

Q. What is the total revenue effect of the proposed gas rate changes?

A. The proposed rates will produce additional revenues of $2,844,132

or 4.1% annually based on projected throughput. Exhibit No. ____ (TAA-1) represents summaries by rate classification of the proposed revenue increase for the projected 2003 test year and is identical to Statement M, Page 1. The exhibit shows the rate number and a description along with the revenues calculated under the present and proposed rates for the projected 2003 test year. The amount and percentage increase is also shown for the proposed revenue increase.

Q. Would you please explain the embedded class cost of service study contained in Statement M?

A. Yes. Turning to Part A, the first report appearing therein is entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the overall requested 11.04% rate of return was to be earned for the demand, energy and customer cost components of each rate schedule.

The next report appearing in Statement M is entitled "Summary." This report shows the results of all of the succeeding reports in summary form. Following this summary report is a detailed report showing the development of each line on the Summary Report.

Part B of Statement M, entitled "Allocation Assignment Report," is a report that shows how the various allocation factors and items directly assigned were applied in producing the various reports shown in Part A.

Part C of Statement M, entitled "Allocation Factor Report," is simply a list of the allocation factors used to produce the various reports shown in Part A. By using the Allocation Assignment Report and the Allocation Factor Report, it can be readily determined how the various components of revenue, expense, and plant were allocated or assigned among the

classes of service.

The class cost of service study is based on the results for North Dakota gas operations as recorded for the 12 months ended December 31, 2001. The study was adjusted to reflect volumes based on normal weather and the resulting revenues and the cost of gas based on current rates effective March 1, 2002.

Q. What were the results of the cost of service study?

A. The results are summarized on Statement M, Part A, page 5. The results are based on the actual results for the 12 months ending December 31, 2001 adjusted to reflect normal weather and current (March 2002) gas costs. These results were used to extrapolate the projected 2003 cost of service on a class basis. The overall North Dakota gas rate of return based on the projected 2003 overall cost of service is 2.33%. The returns by customer class are as shown below:

Residential Service	1.1%
Firm General Service	1.4%
Air Force	18.2%
Small Interruptible	45.5%
Large Interruptible	28.5%

Q. For what purpose has the class cost of service study been used?

A. The study results have been used as a guide in the distribution of total revenue requirements among customers and for the purpose of pricing the various components comprising the total rate applicable to each customer class.

Q. What methodology did you use to apportion the proposed rate increase among the customer classes?

A. In designing the proposed rates to reflect the additional revenue requirements, we have attempted to group the class rates of return more closely about the overall system return.

Given the disparity between the firm and interruptible class contributions to the overall return, the proposed increase was allocated by first increasing the Firm General Service class by an amount that brings the class to the overall rate of return of 11.04% and secondly decreasing the Small Interruptible revenues by 4.1% in order to bring the Small Interruptible class return closer to the return produced by the other interruptible services (Air Force and Large Interruptible). The remaining increase was assigned to the Residential class. No change was proposed for the Air Force and Large Interruptible classes.

Q. What is the percentage of the proposed final increase by class of customer?

A. As shown on Exhibit No. ____ (TAA-1), the proposed increase to each of the classes is as follows:

Class	% Increase
Residential	4.6%
Firm General Service	4.6%
Air Force	---
Small Interruptible	-4.1%
Large Interruptible	---
Overall	**4.1%**

Q. Why did you not propose a decrease for the Air Force or Large Interruptible customer classes?

A. There are basically two reasons. While both the Air Force and Large Interruptible classes are above the overall rate of return, the Small Interruptible class was higher yet and warranted a decrease in order to position all interruptible classes at similar return levels. We also have flexibility in setting the distribution charge applicable to the individual interruptible classes and finally, we did not want to further raise the amount of increase required from the residential and firm general service classes of customers.

Q. What is the effect of the proposed revenue increase on the class returns?

A. The revenue allocation explained above results in an increase in the residential class return from 1.1% to 10.2% and an increase in the firm general service class return from 1.4% to 11.1%. The proposed decrease allocated to the Small Interruptible class results in a reduction in that class return from 45.5% to 30.0%. The class returns for the Air Force and Large Interruptible classes remain unchanged from the projected 2003 level because no change in revenues is proposed for those classes.

Q. What changes are you proposing to the rate form applicable to the firm service customers?

A. In order to accomplish the rate structure objectives which include providing a measure of stability for our customers during periods of abnormal weather, having easily understandable rates for customers, having a rate form that is simple to administer and enhancing fixed cost recovery, the Company is proposing several changes to the firm service rate form. Before I discuss those changes I need to explain a change we

are proposing in the way the components of the gas bill applicable to all customers are to be presented in the future. Our goal is to provide customers with price stability, better price signals and better information that will allow them to understand the nature of their gas bill. We propose to accomplish this by redefining the components of the gas bill applicable to all customers into 3 parts:

1. Basic Service Charge
2. Distribution Delivery Charge and
3. Cost of Gas

I will explain each component more fully below, including the changes that will accomplish the objectives noted above.

1. The Basic Service Charge applicable to each customer class has been set at or nearly at the customer cost level identified in the Class Cost of Service Study for each of the customer classes. This component is currently identified as the "base rate" on the current tariffs and consumer bill. Setting the Basic Service Charge at or nearly at the customer cost level from the class cost of service study will serve to stabilize the portion of the bill currently recovered on a volumetric basis. The Basic Service Charges applicable to the Residential and Firm General Service classes have been stated on a daily basis. Charging this fixed cost on a daily basis better matches the way customers are billed i.e., the days between billing periods vary due to meter reading cycles and customer cut-ins and cut-outs occurring outside their normal billing cycle. Bills for service outside a normal period are currently normalized but the

customer cannot readily determine how the bill was determined. A daily Basic Service Charge will allow the customer to simply multiply the number of days in service during the current billing period (now shown on the bill) times the applicable Basic Service Charge.

2. The Distribution Delivery Charge is proposed to be recovered through a flat commodity charge and the declining block rate currently applicable to Residential and Firm General Service customers under Rates 60, 70 and 72 will be eliminated. The declining block commodity rate is no longer required because the fixed customer related costs that are now recovered through the rate differential assigned to the 1st block of energy (1st 5 dk for residential customers and 1st 15 dk for firm general service customers) will now be properly recovered through the Basic Service Charge. The Distribution Delivery Charge primarily reflects the distribution demand related (fixed) costs discussed by Mr. Feingold plus any customer related costs not recovered through the Basic Service Charge due to the rate design process.

3. The Cost of Gas component is comprised of the items currently recovered through the Purchased Gas Cost Adjustment Rate 88. Under the current rate form, the base cost of gas authorized in the last rate case is buried in the commodity charge component and the changes in gas cost related items are identified separately in a Purchased Gas Cost Adjustment. Under the proposed rate form customers will readily know what

portion of their bill is associated with gas related costs that change upward and downward with the market price of natural gas changes and are subject to the Purchased Gas Cost Adjustment mechanism and not determined in a rate case proceeding such as this.

Q. What are you proposing as Basic Service Charges for the Residential and Firm General Service classes?

A. The Basic Service Charge proposed for customers taking service under Residential Rate 60 has been set at $0.39 per day which reflects an average monthly charge of $11.70. The differential between meters rated less than 500 cubic feet per hour and those rated over 500 cubic feet per hour has been eliminated for the Residential class due to the small number of meters falling into the latter category. The differential has been retained for the Firm General Service Rate 70 rate schedule due to the diversity of customers served under this rate. The Basic Service Charge applicable to Firm General Service customers with meters rated less than 500 cubic feet per hour has been set at $0.80 per day and $1.70 per day for customers requiring the larger meters capable of measuring gas flows of 500 cubic feet per hour or greater. The resulting average monthly charge will be $24.00 and $51.00 respectively.

Q. Would you please explain Exhibit No. ____(TAA-2)?

A. Yes. Exhibit No. ____ (TAA-2) depicts bill comparisons based on typical monthly consumption levels for an annual period for residential and firm general service customers. As shown by the comparisons, the proposed rate structure will result in an average increase of approximately $2.00 per month for the typical Residential customer using 110 dk on an

annual basis. The proposed rate form will also provide customers with price stability during those months where their gas usage may vary significantly due to the weather. For example, a residential customer typically uses 20 dk during the month of January. Under the current rate structure the customer's monthly bill will be $78.38 (based on gas costs as of March 2002). Under the proposed rate structure the customer's bill will be $78.48 – essentially the same amount. However, to the extent the weather is colder than normal and assuming this same customer uses approximately 28 dk the customer would pay $1.03 less under the proposed rate structure. Properly recognizing the fixed costs in a fixed charge minimizes the over-collection of customer related costs by the Company in periods of colder than normal weather as well as minimizing the under-collection during periods of warmer than normal weather.

Q. What changes are you proposing to make to the optional seasonal rates for residential and firm general service customers?

A. The Company is proposing to eliminate the seasonal rate applicable to Residential customers. Since the rate's inception, use by residential customers has been minimal and at the present time there are not any customers taking service under the Residential Service Rate 62 rate schedule. The Optional Seasonal Rate 72 is appropriate for customers such as irrigation loads and municipal swimming pools and has been revised to reflect the proposed Basic Service Charge and Distribution Delivery Charge for Firm General Service Rate 70. The differential between the summer and winter periods continues to be based on the demand component of the cost of gas.

Q. What changes are you proposing to make to the Air Force Rate 64?

A. The Air Force Rate 64 has been revised to reflect an increase in the Basic Service Charge from $750.00 per month to $1,000.00 per month for the Minot Air Force Base and from $35.00 per month to $135.00 per month for the Perimeter Acquisition Radar Site. The commodity charges have been calculated to produce the remaining class revenue requirement. As noted earlier, no overall increase or decrease is proposed for the Air Force. The Air Force Rate 64 tariff sheet has also been revised to exclude the offering of transportation service as the Air Force facilities are now purchasing gas supplies from the Company.

Q. Would you please describe the changes proposed to the Small Interruptible Service Rate 71 and Large Interruptible Service Rate 85 sales rates?

A. Yes. A Basic Service Charge of $100.00 per month has been proposed for the small interruptible class (interruptible customers using less than 100,000 dk annually) and a Basic Service Charge of $675.00 per month is proposed for the large interruptible customer group (customers using 100,000 dk or more annually). The proposed Basic Service Charges reflect the customer costs determined in the embedded class cost of service study while the interruptible commodity charges were calculated as a residual to achieve each class' revenue requirement.

Q. Ms. Aberle, are you proposing any changes to the current interruptible transportation service rates?

A. The only change to the interruptible transportation rates is an increase in the Basic Service Charges to the level identified in the class cost of service study. The current fee of $50.00 per month presently identified as a nomination charge has been included with the Basic

Service Charge applicable to transportation service customers.

Q. Have you prepared a Distribution Delivery Stabilization Mechanism tariff as an alternative as described by Mr. Fox and Mr. Feingold?

A. Yes. A Distribution Delivery Stabilization Mechanism (DDSM) tariff, as discussed by Mr. Feingold, is depicted in Exhibit No. ____(TAA-3). This mechanism, coupled with some level of increase in fixed monthly charges, could be used as an alternative to the implementation of a Basic Service Charge at the customer related cost level identified in the class cost of service study which is the Company's primary proposal. As described in the tariff, the DDSM would be applied to the firm service classes as a per dekatherm adjustment reflecting the amortization of a balancing account representing the over/under recoveries of the Distribution Delivery Charge due to weather related volume fluctuations.

Q. Would you please briefly describe other changes made to the Company's gas tariff?

A. Yes, following is a description of other changes the Company is proposing to make to its gas tariff:

- A Rate Summary Sheet has been added to allow readers to see, at a glance, all charges associated with a particular rate. Page 2 of the Rate Summary Sheet provides a summary of other miscellaneous charges that are discussed throughout the entire gas tariff.
- The penalty for failure to curtail or interrupt, applicable under each of the interruptible sales and transportation service schedules has been increased from $10.00 per dk to $50.00 per dk in order to sensitize the critical nature of a call for

interruption and to provide sufficient incentive for a customer to interrupt or curtail their use of gas when called upon to do so.

- Firm Gas Transportation Service Rate 84, currently available for the firm requirements of interruptible customers, has been eliminated due to lack of customer interest in this rate option.
- The fee charged when a check is returned for non-payment back to the Company has been increased to $20.00 to reflect the current going rate charged by banks and other businesses.
- The reconnection fees for seasonal customers will now be tied to the Basic Service Charge that would have been applied during the period the customer was out of service with a minimum set at the actual cost associated with reconnecting the service. The reconnection charge for a customer disconnected for nonpayment of bills has been increased to $30.00, the actual cost of reconnecting service.
- Firm Gas Service Extension Policy Rate 120 and Rate 124 related to service line installations have been revised to reflect the Company's proposal to own all prospective service line installations as discussed by Mr. Fox and Ms. Mulkern in their testimony. The Company is proposing to install service lines that are cost justified by the expected connected load at no cost to the customer. A customer contribution will be required for the portion of the installation not supported by the expected connected load in accordance with the Maximum Allowable Investment formula currently used under Firm Gas Service Extension Policy Rate 120. The change in service line policy

has allowed the elimination of the Rate Zone 1 and Rate Zone 2 designations that were used to differentiate between those communities where the customer owned the service lines (Zone 1) and the communities where the company owned the service lines (Zone 2).

- Minor changes which are self explanatory have been made to the majority of the rate schedules. These changes are clearly denoted on the tariff sheets reflecting the legislative format.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA

Customer Class/Rate	Projected 2003 Bills	Projected 2003 Dk	Projected 2003 Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	878,101	7,899,840	$39,198,383	$40,988,358	$1,789,975	4.6%
Firm General Service - Rate 70	135,039	5,609,220	24,779,326	25,914,843	1,135,517	4.6%
Air Force - Rate 64						
Firm	12	36,450	132,624	132,621		
Interruptible	24	1,014,790	2,448,094	2,448,235		
Total Air Force	36	1,051,240	2,580,718	2,580,856	138	0.0%
Small Interruptible						
Sales - Rate 71	852	489,700	1,403,132			
Transport - Rate 81	860	1,030,440	557,408			
Total Small Interruptible	1,712	1,520,140	1,960,540	1,879,181	(81,359)	-4.1%
Large Interruptible						
Sales - Rate 85	0	0	0			
Transport - Rate 82	108	2,246,820	342,735			
Total Large Interruptible	108	2,246,820	342,735	342,596	(139)	0.0%
Total North Dakota	1,014,996	18,327,260	$68,861,702	$71,705,834	$2,844,132	4.1%

Case No. _____
Exhibit No. _____(TAA-1)
Page 1 of 1

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RESIDENTIAL GAS SERVICE - Rate 60
Bill Comparison

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	20	$78.38	$78.48	$0.10	0.13%
February	14	57.49	58.45	0.96	1.67%
March	14	57.49	58.45	0.96	1.67%
April	9	40.08	41.75	1.67	4.17%
May	6	29.64	31.73	2.09	7.05%
June	3	18.30	21.72	3.42	18.69%
July	2	14.36	18.38	4.02	27.99%
August	2	14.36	18.38	4.02	27.99%
September	4	22.23	25.06	2.83	12.73%
October	8	36.60	38.41	1.81	4.95%
November	12	50.53	51.77	1.24	2.45%
December	16	64.45	65.12	0.67	1.04%
Total	110	$483.91	$507.70	$23.79	4.92%

PRESENT RATE 60: 1/		PROPOSED RATE 60: 2/	
Base Rat	$6.50	Basic Delivery Charge	$11.70
1st 5 dk	$3.932	Distribution Delivery	$0.432
Over 5 dl	3.481	Cost of Gas	$2.907

1/ Rate effective March 1, 2002 for Rate 60 Zone 1 (Meters rated < 500 cubic feet per hour).
2/ Includes March 2002 Cost of Gas based on .45% loss factor plus surcharge & margin sharing.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
Original Sheet No. 37

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 95

APPLICABILITY:

This rate schedule represents a Distribution Delivery Stabilization Mechanism (DDSM) and specifies the procedure to be utilized to correct for the over/under collection of distribution delivery charge revenues due to weather fluctuations during the heating season defined as October 1 through April 30. Service provided under the Company's Residential Rate 60 and Firm General Service Rate 70 shall be subject to decreases or increases under the DDSM.

EFFECTIVE DATE:

Adjustments under this DDSM will commence in May 2003 and continue through April 2004. The DDSM will be recalculated on an annual basis and a new DDSM will be filed to be effective May 1 each year thereafter.

DISTRIBUTION DELIVERY STABILIZATION MECHANISM:

A DDSM will be determined for each rate schedule subject to the DDSM and shall be expressed as rate per dk. Monthly bills beginning with the first billing cycle following May 1, 2003 and each May 1st thereafter, will be adjusted (decreased or increased) by the application of a DDSM rate computed in accordance with the procedures based on temperature conditions for the winter heating season beginning November 1, 2002 ending March 31, 2003, and each heating season thereafter, compared to normal temperature levels established in the most recent general rate case. The DDSM rate will be stated as a surcharge or credit on all rate schedules to which the DDSM is applicable. A DDSM rate will be computed for each applicable rate schedule to be effective for a period of one year. Following the initial one-year term, and annually thereafter, the DDSM rate calculation shall include any over or under collection of DDSM revenue from the preceding twelve-month recovery period.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
Original Sheet No.37.1

Distribution Delivery Stabilization Mechanism Rate 95

DDSM RATE CALCULATION:

A DDSM shall be determined for each rate schedule subject to the DDSM and shall be expressed as a rate per dk. In order to calculate the respective DDSM rates, the winter season HDD variation from the normal HDDs will be determined and multiplied by the temperature sensitive consumption per customer per HDD, as determined in the most recent general rate case. The resulting product shall be multiplied by the applicable Distribution Delivery Charge rate and then divided by the average annual use per customer to determine a dollar amount per dk.

$$DDSM_i = \frac{R_i\,(DDF_i\,(NDD - ADD)) + (PDDSM_i - ADDSM_i)}{ANU_i}$$

Where:

$DDSM_i$ = Distribution Delivery Stabilization dollar amount per dk

i = Applicable rate class subject to the DDSM

R_i = Applicable Distribution Delivery Charge per dk

DDF_i = Temperature sensitive use per customer per degree day

NDD = Normal degree days for the winter service period

ADD = Actual degree days for the winter service period

ANU_i = Average normal use per customer for the prospective twelve month period

$PDDSM_i$= Projected DDSM revenue from the preceding twelve month period

$ADDSM_i$= Actual DDSM revenue recovered from the preceding twelve month period

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
Original Sheet No.37.2

Distribution Delivery Stabilization Mechanism Rate 95

DEFINITIONS:

Heating Degree Days	-	The difference between the average of the daily high and low temperature subtracted from 60 degrees Fahrenheit.
Normal Degree Days	-	The heating degree days that are based on the 30 year average ending June 30, 2001.
Actual Degree Days	-	The actual degree days reported by National Weather Service Stations for applicable service areas in North Dakota weighted by customers.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **29th day of August, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and containing a photocopy of:

Order Granting Trade Secret Protection

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7099 3220 0002 8482 2851

Sharon Helbling further deposes and says that on the **29th day of August, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope by regular mail, with postage fully prepaid, securely sealed, each containing a photocopy of the same.

C Wayne Fox
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

Charles King
120 Court St
Castine ME 04421

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **29th day of August, 2002**.

Sandra L. Scott

Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

APPROVED
DATE: 8-28-02
KMF

MOTION

August 28, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission adopt the Order granting trade secret protection in this proceeding.

Sdh

46 **PU-399-02-183** Pages: 1

Motion adopting Trade Secret Order

by Public Service Commission

08/28/2002 CC: Comm Legal PUD (3) Mike ALJ .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

ORDER GRANTING TRADE SECRET PROTECTION

August 28, 2002

On August 9, 2002, Montana-Dakota Utilities Co. (MDU) filed an application for a protective order limiting the disclosure of trade secret information included in responses to the certain information sought by the Commission Staff (Staff) as part of its First Data Requests. On August 22, 2002, MDU filed an application for a protective order limiting the disclosure of trade secret information included in responses to the certain information sought by the Staff as part of its Second Follow-Up Data Requests. MDU provides the general description of the nature of the information sought to be protected, as follows:

RESPONSES TO NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF'S FIRST DATA REQUESTS

Request No. 2 -- The response is a page from an actuarial report by Towers Perrin on the performance of the health and welfare benefit plans for both bargaining unit and non-bargaining unit employees.

Request No. 3 -- The response is information concerning the amount of short-term borrowings by MDU and MDU Resources at the end of each month in 2000 and 2001 along with the weighted average cost of MDU's short-term borrowings.

RESPONSES TO NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF'S SECOND FOLLOW-UP DATA REQUESTS

Request No. 2 -- The response is documentation relating to senior notes, commercial paper, revolving line of credit and term agreements.

Request No. 3 -- The response is the breakdown of year-end 2001, 2002, and 2003 "Subsidiary Portion of Balance" by specific subsidiary.

Request No. 4 -- The response is the data, workpapers, and allocation ratios by which policies and procedures outlined in Response No. 39, Attachment A are implemented.

MDU requests trade secret protection for MDU Resources subsidiary information. MDU states that such information is not publicly available and is treated as confidential business information. MDU believes that disclosure of the MDU Resources information would be of independent economic value to competitors and would create a competitive

would be of independent economic value to competitors and would create a competitive disadvantage for MDU Resources if publicly disclosed to others because of the competitive nature of the businesses conducted by the various subsidiaries.

N.D.C.C. Section 47-25.1-01(4) defines "trade secret" as:

"Trade secret" means information, including a formula, pattern, compilation, program, device, method, technique, or process, that:

a. Derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by other persons who can obtain economic value from its disclosure or use; and

b. Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy.

On August 14, 2002 Staff filed its response to MDU's request for trade secret protection on responses to Staff's First Data Requests. On August 23, 2002, Staff filed its response to MDU's request for trade secret protection on responses to Staff's Second Follow-Up Data Requests. Staff noted that the information qualifies as trade secret and that MDU's application satisfies the requirements of the law that allows the Commission to grant trade secret protection and recommended granting the application. Staff noted that the Commission's process provides a means for interested parties to review trade secret documents upon signing a nondisclosure agreement.

Order

The Commission Orders:

1. MDU's application for trade secret protection filed August 9, 2002 is GRANTED.

2. MDU's application for trade secret protection filed August 22, 2002 is GRANTED.

3. The Commission, under N.D.A.C. § 69-02-02-11, suspends the requirements of N.D.A.C. § 69-02-09-07, to the limited extent necessary so that the materials which are hereby granted trade secret status may be supplied by Montana-Dakota Utilities Co. to Mr. Charles King outside the Commission office, for his inspection and review for purposes related to his engagement by the Commission as a consultant in this matter, after which he will return said materials to the Company.

PUBLIC SERVICE COMMISSION

Anthony T. Clark	**Susan E. Wefald**	**Leo M. Reinbold**
Commissioner	**President**	**Commissioner**

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

August 23, 2002

Mr. Jon H. Mielke
Public Service Commission
600 E Boulevard Ave. Dept. 408
Bismarck, ND 58505-0480

RECEIVED
AUG 23 2002
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

RE: **Montana-Dakota Utilities Co.**
Natural Gas Rate Increase Application
Case No. PU-399-02-183

Dear Jon:

Enclosed for filing in the above referenced case is the original and seven copies of the **Staff Response to Montana-Dakota's Application Requesting Trade Secret Protection for Responses to Data Requests**.

Thank you.

Sincerely,

William W. Binek
Chief Counsel

WWBsls
Enclosure

C: William P. Pearce, Attorney
Douglas W Schulz, Attorney
Don R. Ball

44 **PU-399-02-183** Pages: 1

Cover letter re filing

by Public Service Commission

08/23/2002 CC: Comm Legal PUD (3) Mike ALJ .

RECEIVED
AUG 23 2002
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

STAFF RESPONSE TO MONTANA-DAKOTA'S APPLICATION REQUESTING TRADE SECRET PROTECTION FOR RESPONSES TO DATA REQUESTS

On August 22, 2002, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota) filed an application for a protective order limiting the disclosure of trade secret information included in responses to the Commission Staff's second follow-up data requests that are served on the Commission staff in this proceeding. Montana-Dakota provides the general description of the nature of the information sought to be protected, as follows:

General Description of the Nature of the Information Sought to be Protected.

1. **REQUEST NO. 2.** The request is a follow-up request to Request No. 18 and requests documentation to support the statement that the senior notes, commercial paper, revolving line of credit and term agreements are related to the subsidiaries only, not to Montana-Dakota along with identifying the specific subsidiary to which the issue of senior notes, commercial paper, revolving line of credit or term credit is related.

2. **REQUEST NO. 3.** The request is a follow-up to Request No. 19 and requests a breakdown of the year 2001, 2002 and 2003 "Subsidiary Portion of Balance" by specific subsidiary.

3. **REQUEST NO. 4.** The request is a follow-up to Request No. 39 and requests data, workpapers, and allocation ratios by which the policies and procedures outlined in Response No. 39, Attachment A are implemented.

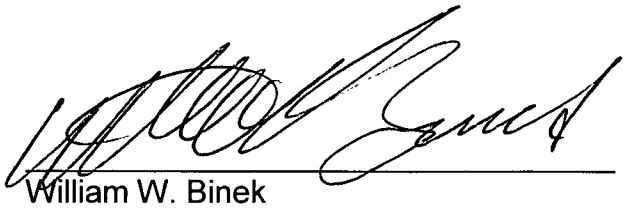
Montana-Dakota requests trade secret protection for MDU Resources subsidiary information. Montana-Dakota states that such information is not publicly available, and

is not only treated as confidential business information, but information which cannot be selectively disclosed without violating the public reporting requirements of the Securities and Exchange Commission. Montana-Dakota believes that disclosure of the MDU Resources information would be of independent economic value to competitors and would create a competitive disadvantage for MDU Resources if publicly disclosed to others because of the competitive nature of the businesses conducted by the various subsidiaries.

Staff has reviewed the information for which Montana Dakota requests trade secret protection. Staff believes that the information qualifies as trade secret and that Montana-Dakota's application satisfies the requirements of the law, which allows the Commission to grant trade secret protection in this proceeding. The Commission's process provides a means for interested parties to review trade secret documents upon signing a nondisclosure agreement.

For reasons set forth above, staff recommends that the Commission grant Montana-Dakota's Application For Trade Secret Protection in this case.

Dated August 23, 2002.



William W. Binek
Chief Counsel

RECEIVED
AUG
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra L. Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **23rd day of August, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **four** envelopes with first class postage, fully prepaid, securely sealed and each containing a photocopy of:

Staff Response to Montana-Dakota's Application Requesting Trade Secret Protection For Data Requests

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

Douglas W Schulz
Senior Attorney
MDU Resources Group Inc.
P O Box 5650
Bismarck ND 58506-5650

William P Pearce
Attorney at Law
Pearce & Durick
P O Box 400
Bismarck ND 58502-0400

Charles W King
Snavely King Majoros O'Connor & Lee Inc
1220 L Street NW, Suite 410
Washington DC 20005

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sandra L. Scott

CHARLENE A. MAGSTADT
Notary Public, State of NORTH DAKOTA
My Commission Expires Jan. 7, 2004

Subscribed and sworn to before me
this **23rd day of August 2002**.

Notary Public Charlene A. Magstadt

SEAL

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

RECEIVED
AUG 22 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

August 22, 2002

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505-0480

Re: Case No. PU-399-02-183
Application for Trade Secret Protection

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith respectfully files an original and seven (7) copies of an Application for Trade Secret Protection covering certain information sought by the Commission Staff as part of its Second Follow-Up Data Requests as fully described in the attached Application.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball

Donald R. Ball
Director of Regulatory Affairs

Attachment
cc: Douglas W. Schulz

41 PU-399-02-183 Pages: 1
Cover letter re filing
by Montana-Dakota Utilities Co., a Division of MDU R
08/22/2002 CC: Comm Legal PUD (3) Mike ALJ

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., For Authority to Establish Increased Rates for Natural Gas Service	Case No. PU-399-02-183

APPLICATION FOR TRADE SECRET PROTECTION

COMES NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota) and respectfully moves the Commission for entry of a trade secret protective order under §69-02-09-01 of the North Dakota Administrative Code. The purpose of the requested protective order is to protect against public disclosure of trade secret information as defined by NDCC §47-25.1-(4).

The specific information which needs protection at this time is certain information requested by the Commission Staff in its Second Follow-Up Data Requests as follows:

1. Request No. 2. The request is a follow-up to Request No. 18 and requests documentation to support the statement that (t)he senior notes, commercial paper, revolving line of credit and term agreements are related to the subsidiaries only, not to Montana-Dakota along with identifying the specific subsidiary to which the issue of senior notes, commercial paper, revolving line of credit or term credit is related. Montana-Dakota requests that trade secret protection be given to the MDU Resources subsidiary information. Such information is not publicly available, and is not only treated as confidential

business information, but information which cannot be selectively disclosed without violating the public reporting requirements of the Securities and Exchange Commission. Montana-Dakota believes that disclosure of the MDU Resources information would be of independent economic value to competitors and would create a competitive disadvantage for MDU Resources if publicly disclosed to others because of the competitive nature of the businesses conducted by the various subsidiaries.

2. Request No. 3. The request is a follow-up to Request No. 19 and requests a breakdown of the year-end 2001, 2002 and 2003 "Subsidiary Portion of Balance" by specific subsidiary. Montana-Dakota requests that trade secret protection be given to the MDU Resources subsidiary information. Such information is not publicly available, and is not only treated as confidential business information, but information which cannot be selectively disclosed without violating the public reporting requirements of the Securities and Exchange Commission. Montana-Dakota believes that disclosure of the MDU Resources information would be of independent economic value to competitors and would create a competitive disadvantage for MDU Resources if publicly disclosed to others because of the competitive nature of the businesses conducted by the various subsidiaries.
3. Request No. 4. The request is a follow-up to Request No. 39 and requests data, workpapers, and allocation ratios by which the policies and procedures outlined in Response No. 39, Attachment A are implemented. Montana-Dakota requests that trade secret protection be given to the MDU Resources

subsidiary information. Such information is not publicly available, and is not only treated as confidential business information, but information which cannot be selectively disclosed without violating the public reporting requirements of the Securities and Exchange Commission. Montana-Dakota believes that disclosure of the MDU Resources information would be of independent economic value to competitors and would create a competitive disadvantage for MDU Resources if publicly disclosed to others because of the competitive nature of the businesses conducted by the various subsidiaries.

In accordance with §69-02-09-02 of the North Dakota Administrative Code, one copy of the trade secret material is provided in the enclosed sealed envelope which is labeled; TRADE SECRET – PRIVATE.

Respectfully submitted this 22nd day of August, 2002.

MONTANA-DAKOTA UTILITIES CO.,
A Division of MDU Resources Group, Inc.

By Donald R. Ball
Donald R. Ball
Director of Regulatory Affairs

Public Service Commission
State of North Dakota

RECEIVED
AUG 14 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

August 14, 2002

Mr. Jon H. Mielke
Public Service Commission
600 E Boulevard Ave. Dept. 408
Bismarck, ND 58505-0480

RE: **Montana-Dakota Utilities Co.**
Natural Gas Rate Increase Application
Case No. PU-399-02-183

Dear Jon:

Enclosed for filing in the above referenced case is the original and seven copies of the **Staff Response to Montana-Dakota's Application Requesting Trade Secret Protection for Responses to Data Requests**.

Thank you.

Sincerely,

William W. Binek
Chief Counsel

WWBsls
Enclosure

C: William P. Pearce, Attorney
Douglas W Schulz, Attorney
Don R. Ball

39 **PU-399-02-183** Pages: 1

Cover letter re Staff Response

by Public Service Commission by William W. Binek, Ct

08/14/2002 CC: Comm Legal PUD (3) Mike ALJ

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AUG 14 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

STAFF RESPONSE TO MONTANA-DAKOTA'S APPLICATION REQUESTING TRADE SECRET PROTECTION FOR RESPONSES TO DATA REQUESTS

On October 2, 2000, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota) filed an application for a protective order limiting the disclosure of trade secret information included in responses to the Commission Staff's first set of data requests that are served on the Commission staff in this proceeding. Montana-Dakota provides the general description of the nature of the information sought to be protected, as follows:

General Description of the Nature of the Information Sought to be Protected.

1. **REQUEST NO. 2.** The request refers to statements A-F, G-L, N-O and requests in hard copy and electronic format all workpapers underlying the company's filing. Page 67 if the workpapers supporting the statements is a page from an actuarial report by Towers Perrin on the performance of the health and welfare benefit plans for both bargaining unit and non-bargaining unit employees. The report is prepared by Towers Perrin for a number of MDU Resources Group, Inc. (MDU Resources) companies and not just Montana-Dakota.

2. **REQUEST NO. 3.** The request refers to statements A-F, G-L, N-O and specifically Statement A, asking for the amount of short-term borrowings by Montana-Dakota and MDU Resources respectively at the end of each month in 2000 and 2001 along with the weighted average cost of Montana-Dakota's short-term borrowings.

Montana-Dakota requests trade secret protection for MDU Resources information including the Towers Perrin report insofar as it relates to MDU Resources

subsidiaries. Montana-Dakota states that such information is not publicly available, and is not only treated as confidential business information, but information which cannot be selectively disclosed without violating the public reporting requirements of the Securities and Exchange Commission. Montana-Dakota believes that disclosure of the MDU Resources information would be of independent economic value to competitors and would create a competitive disadvantage for MDU Resources if publicly disclosed to others because of the competitive nature of the businesses conducted by the various subsidiaries.

Staff has reviewed the information for which Montana Dakota requests trade secret protection. Staff believes that the information qualifies as trade secret and that Montana-Dakota's application satisfies the requirements of the law, which allows the Commission to grant trade secret protection in this proceeding. The Commission's process provides a means for interested parties to review trade secret documents upon signing a nondisclosure agreement.

For reasons set forth above, staff recommends that the Commission grant Montana-Dakota's Application For Trade Secret Protection in this case.

Dated August 14, 2002.

William W. Binek
Chief Counsel

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra L. Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **14th day of August, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **four** envelopes with first class postage, fully prepaid, securely sealed and each containing a photocopy of:

Staff Response to Montana-Dakota's Application Requesting Trade Secret Protection For Data Requests

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

Douglas W Schulz
Senior Attorney
MDU Resources Group Inc.
P O Box 5650
Bismarck ND 58506-5650

William P Pearce
Attorney at Law
Pearce & Durick
P O Box 400
Bismarck ND 58502-0400

Charles W King
Snavely King Majoros O'Connor & Lee Inc
1220 L Street NW, Suite 410
Washington DC 20005

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **14th day of August, 2002**.

Notary Public

SEAL

CHARLENE A. MAGSTADT
Notary Public, State of NORTH DAKOTA
My Commission Expires Jan. 7, 2004

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

RECEIVED
AUG - 9 2002
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

August 9, 2002

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505-0480

Re: Case No. PU-399-02-183
Application for Trade Secret Protection

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith respectfully files an original and seven (7) copies of an Application for Trade Secret Protection covering certain information sought by the Commission Staff as part of its First Data Requests as fully described in the attached Application.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball
Director of Regulatory Affairs

Attachment
cc: Douglas W. Schulz

36 PU-399-02-183 Pages: 1
Cover letter re filing
by Montana-Dakota Utilities Co., a Division of MDU Re
08/09/2002 CC: Comm Legal PUD (3) Mike ALJ

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., For Authority to Establish Increased Rates for Natural Gas Service	Case No. PU-399-02-183

APPLICATION FOR TRADE SECRET PROTECTION

COMES NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota) and respectfully moves the Commission for entry of a trade secret protective order under §69-02-09-01 of the North Dakota Administrative Code. The purpose of the requested protective order is to protect against public disclosure of trade secret information as defined by NDCC §47-25.1-(4).

The specific information which needs protection at this time is certain information requested by the Commission Staff in its First Data Requests as follows:

1. Request No. 2. The request refers to Statements A-F, G-L, N-O and requests in hard copy and electronic format all workpapers underlying the company's filing. Page 67 of the workpapers supporting the statements is a page from an actuarial report by Towers Perrin on the performance of the health and welfare benefit plans for both bargaining unit and non-bargaining unit employees. The report is prepared by Towers Perrin for a number of MDU Resources Group, Inc. (MDU Resources) companies and not just Montana-Dakota. Neither MDU Resources nor Montana-Dakota publicly report or disclose this information and it is considered and treated as confidential

business information. Montana-Dakota requests trade secret protection for the Towers Perrin report insofar as it relates to MDU Resources subsidiaries. Montana-Dakota believes that disclosure of the MDU Resources subsidiary information would be of independent economic value to competitors and would create a competitive disadvantage for MDU Resources if publicly disclosed to others because of the competitive nature of the businesses conducted by the various subsidiaries. Access to such information by competitors would provide them with a portion of the costs of doing business and thus a competitive advantage.

2. Request No. 3. The request refers to Statements A-F, G-L, N-O and specifically Statement A, asking for the amount of short-term borrowings by Montana-Dakota and MDU Resources respectively at the end of each month in 2000 and 2001 along with the weighted average cost of Montana-Dakota's short-term borrowings. Montana-Dakota requests that trade secret protection be given to the MDU Resources information. Such information is not publicly available, and is not only treated as confidential business information, but information which cannot be selectively disclosed without violating the public reporting requirements of the Securities and Exchange Commission. Montana-Dakota believes that disclosure of the MDU Resources information would be of independent economic value to competitors and would create a competitive disadvantage for MDU Resources if publicly disclosed to others because of the competitive nature of the businesses conducted by the various subsidiaries.

In accordance with §69-02-09-02 of the North Dakota Administrative Code, one copy of the trade secret material is provided in the enclosed sealed envelope which is labeled; TRADE SECRET – PRIVATE.

Respectfully submitted this 9th day of August, 2002.

MONTANA-DAKOTA UTILITIES CO.,
A Division of MDU Resources Group, Inc.

By Donald R. Ball
Donald R. Ball
Director of Regulatory Affairs

APPROVED
DATE: 8-2-02
KMF

MOTION

August 2, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission appoint Bill Binek and Patrick Fahn as advocacy staff and Mike Diller, Illona Jeffcoat-Sacco and Jerry Lein as advisory staff in Montana-Dakota Utilities Co.'s s Natural Gas Rate Increase application in Case No. PU-399-02-183.

Sdh

33 **PU-399-02-183** Pages: 1

Mtn appoint Binek-Fahn as Advocacy staff/Illona-Lein-Diller as Advisory staff by Public Service Commission

07/02/2002 CC. Comm Legal PUD (3) Mike ALJ .

Statement Date
06/30/02

800340

Charges or Payments received after this date will appear on next statement
Terms:

KFYR-AM
CLEAR CHANNEL BROADCASTING, INC.
5584 COLLECTIONS CENTER DRIVE
CHICAGO, IL 60693
(701) 258-5555

KFYR NTR

770.0 -
001 -
22183 -
12 -2001

PUBLIC SERVICE COMMISSION
600 E BOULEVARD AVE
12TH & 13TH FLOOR
DEPT. 408
BISMARCK, ND 58505

PAID PU-399-02-183

REFERENCE DOCUMENT
NUMBER PS 2440 11303

Date				Amount
06/30/02	3249-00002-0000	Invoice: MDU PUBLIC MEETING - 26 DUBS	103.00	103.(

32 **PU-399-02-183** Pages: 2

Bill for Public Announcement
tapes/payment receipt
by KFYR

07/01/2002 CC: Comm Legal PUD (3) Mike ALJ

Jun	May	Apr	Mar +	Please Pay This Amount
103.00	0.00	0.00	0.00	103.00

Statement Date
06/30/02

Charges or Payments received after this date will appear on next statement
Terms:

800340

KFYR-AM
CLEAR CHANNEL BROADCASTING, INC.
5584 COLLECTIONS CENTER DRIVE
CHICAGO,
(701) 258-5

KFYR NTR

7700

PUBLIC S
600 E BOU
12TH & 13
DEPT. 408
BISMARC

Date	
06/30/02	3

SFN14599

CHECK STUB (FOR DEPARTMENT USE ONLY)

DEPARTMENT: PUBLIC SERVICE COMMISSIO
WARRANT: 06716152 DATE: 07/17/02
VENDOR NAME: KFYR-AM & KYYY-FM
CLEAR CHANNEL BROADCASTING INC
5584 COLLECTIONS CENTER DR
CHICAGO IL 60693-0055

FM/BIEN: 12/01 VENDOR: 0000800340-00

REF. DOC.	CLAIM	FUND	COST CENTER	OBJECT	APPN	LN	PROJECT	GRANT	AMOUNT
PS011303	599934	001	7700	2440	408	30	22193- -		103.00

CHECK AMOUNT 103.00

Jun	May	Apr	Mar +	Please Pay This Amount
103.00	0.00	0.00	0.00	103.00

SNAVELY KING MAJOROS O'CONNOR & LEE, INC.
ECONOMIC AND MANAGEMENT CONSULTANTS

RECEIVED
JUL 19 2002
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

July 15, 2002

Mike Diller
Director of Accounting
Public Service Commission
State of North Dakota
600 E Boulevard Ave, Dept 408
Bismarck, ND 58505-0480

Dear Mr. Diller:

Enclosed herewith is the signed copy of the Contract No. PU-399-02-183 between the Public Service Commission of North Dakota and Snavely King Majoros O'Connor & Lee, Inc. This contract covers consulting and expert witness services in connection with the application of Montana-Dakota Utilities Co. for an increase in its natural gas rates.

I very much look forward to working with you on this important project.

Sincerely,

Charles W. King
President

31 **PU-399-02-183** Pages: 1

Cover letter re signed contract

by Snavely King Majoros O'Connor & Lee, Inc.

07/19/2002 CC: Comm Legal PUD (3) Mike ALJ

1220 L STREET, NW, SUITE 410, WASHINGTON, DC 20005-(202)371-1111, FAX (202)842-4966

1471 CASTILLO DELMAR, CAROLINA, PR 00979-(809)783-7683, FAX(809)783-7559

CONTRACT

Administrator: Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505-0480
(701) 328-2400

Date: July 3, 2002

Anthony T. Clark	Susan E. Wefald	Leo M. Reinbold
Commissioner	**President**	**Commissioner**

Contractor

Snavely King Majoros O'Connor & Lee, Inc.
Name

1220 L St NW Ste 410	Washington D C 20005	202-371-9156
Address	**City/State/Zip**	**Phone**

Charles W. King	President
Typed Name	**Title**
Signature	**Date** July 15 2002

Agreement Information

Contract No.: PU-445-02

Start Date: 7-3-02

End Date: 6-30-03

Program Title: PU-399-02-183

Type of Contract: ( ) Fixed Price
(X) Cost Reimb. ( ) Unit Price
( ) Other

Budget Information

Cost Center: 7700

Services: $48,534

Optional on-site review: 0

Expenses: 0

ID 52-0901220

Type of Contractor: ( ) Individual
(X) Corporation ( ) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other

This contract is entered into between the above two parties. This contract consists of this sheet, general provisions and specific provisions.

Signed Contract No. PU-445-02
by Snavely King Majoros O'Connor & Lee, Inc.
07/19/2002 CC: Comm Legal PUD (3) Mike ALJ

GENERAL PROVISIONS

CONTRACTUAL FEATURES

Legal Authority

The Contractor assures that it possesses legal authority to participate in this contract.

Assignment/Subcontracting

The Contractor may not assign this contract or any part thereof, or assign any of the monies to be paid hereunder, nor shall any part of the work done or material furnished under this contract be sublet.

The Contractor may not enter into subcontracts for any of the work contemplated under this contract unless included in the specific provisions of this contract.

Termination

The Commission, by ten days written notice listing causes and reasons, may terminate this contract in whole or in part when it is determined that the Contractor has failed to meet the conditions of the contract. The Commission will be liable only for payment provisions of this contract for services satisfactorily rendered prior to the effective date of termination.

Significant deviation from performance standards in this contract may result in reduced or terminated financial participation of the Contractor, subsequent to negotiations with the Commission.

The Contractor or the Commission may terminate this contract in whole or in part upon settlement or when both parties agree that the continuation of the contract would not produce results commensurate with further expenditures of funds. The two parties shall agree upon the termination conditions including effective date and in the case of partial terminations, that portion to be terminated.

In the event state or federal funds are reduced or terminated, the financial participation of the Commission may be reduced or terminated.

Disputes

The Contractor agrees to attempt to resolve disputes arising from this contract by administrative process and negotiations in lieu of litigation. Continued performance by the Contractor during disputes is assured.

Any dispute concerning a question of fact arising under this contract which is not settled by the informal means shall be decided by the authorized representative of the Commission who shall reduce the decision to writing and mail or otherwise furnish a copy thereof to the Contractor.

The Contractor shall be afforded an opportunity to be heard and to offer evidence in support of an appeal. Pending final decision of a dispute, the Contractor shall proceed diligently with the performance of the contract and in accordance with the decision of the Commission.

FISCAL RESPONSIBILITIES

Records

The Contractor agrees to maintain program records required by the Commission and to produce program narrative and statistical data at times prescribed by the Commission.

The Contractor agrees to maintain and retain all books, records, and other documents required by the Commission relevant to this agreement for four years after final payment. Records shall be retained beyond four years if audit findings have not been resolved.

No Claim for Additional Work

No claim for additional services not specifically herein provided, done, or furnished by the Contractor will be allowed, nor shall the Contractor do any work or furnish any material not covered by the contract, unless such work is ordered in writing by the Commission.

Time Keeping Procedures

The Contractor shall require employees and subcontractors, if applicable, whose positions are funded under this contract or included as match, to maintain adequate documentation for services provided. For positions that are funded from more than one source, an analysis of duties performed by program shall also be prepared.

Monitoring, Evaluation and Audit

The Contractor agrees to cooperate with any monitoring, evaluating and/or audit conducted by the Commission, or their designees who shall have full access to and the right to examine all books, records and other relevant documents.

The Contractor agrees to take immediate corrective action on deficiencies disclosed through program monitoring of costs disallowed in the course of an audit, review, or monitoring.

PROGRAM REQUIREMENTS

Equal Opportunity

No individual shall be excluded from participation in, denied the benefits of, subjected to discrimination under, or denied employment in the administration of or in connection with this contract because of race, color, disability, or political affiliation or belief.

The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship.

Nondiscrimination

This contract and any subcontract hereunder is subject to the Age Discrimination Act of 1975, Section 504 of the Rehabilitation Act, Title VI of the Civil Rights of 1964 and the Americans with Disabilities Act of 1990.

Copyrights and Rights in Data

The contractor agrees that any plans, drawings, designs, specifications, computer programs (which are substantially paid for with federal grant or state funds), technical reports, operation manuals and other work submitted with a proposal or grant application or which are specified to be delivered under this contract or which are developed or produced and paid for under this contract (referred to in this clause as "subject data") are subject to the rights of the Commission to use, duplicate and disclose the subject data in whole or in part, in any manner for any purpose whatsoever, and have others do so. If the material is copyrightable, the contractor may copyright the material, subject to the rights in the government, but the Commission reserves a royalty-free, non-exclusive and irrevocable license to reproduce, publish and use the material, in whole or in part, and to authorize others to do so. The contractor shall include provisions appropriate to effectuate the purposes of this condition in all subcontracts expected to produce copyrightable "subject data."

SPECIFIC PROVISIONS
July 3, 2002

Purpose

Montana-Dakota Utilities Co. has filed an application to increase its North Dakota natural gas rates. To fully pursue and represent its case, staff requires assistance to analyze MDU's filing and to provide written and oral testimony. The contractor will determine the appropriate cost of service and rate design. The work will include sufficient detail as is necessary to successfully testify under cross-examination.

All work under this contract must be completed prior to the commission's fiscal year ending June 30, 2003. More importantly, the work needs to be sufficiently complete so as to provide written testimony by August 30, 2002 and oral testimony at the technical hearing to be held October 7-8, 2002.

The specific purpose is to investigate, analyze and provide testimony proposing the proper rate base, cost of capital, revenues and expenses, depreciation rates and rate design necessary to yield the opportunity for MDU to earn a fair and reasonable return on its natural gas investment in North Dakota including:

1. Professional analysis and review of filing.
2. Prepare and conduct discovery.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff updated.
4. Prepare written testimony and provide an advanced copy to staff for review prior to submitting as a formal document.
5. Prepare written and oral testimony in rebuttal to testimony of other parties in the proceeding.
6. Testify at the hearing.
7. Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings.
8. After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed commission decision.

Compensation

The Contractor will be compensated based on periodic submittal of progress reports. Final payment will be made upon satisfactory completion of the described project work, as determined by the commission.

In the event the case is settled or this agreement is otherwise terminated prior to completion of project work, then compensation will be awarded for work satisfactorily completed.

No part of this contract may be assigned, sublet or subcontracted.

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

July 3, 2002

Charles W King
Snavely King Majoros O'Connor & Lee Inc
1220 L St NW Ste 410
Washington D C 20005

Dear Mr. King:

Enclosed is Contract No. PU-445-02 for consulting services in Case No. PU-399-02-183. Please sign both copies of the contract, keep one copy for your files and return one copy to me.

When submitting invoices for payment, **please send them directly to me** and identify the case number for each invoiced amount.

If you have any questions, please call me at 701-328-4079.

Sincerely,

Mike Diller
Director of Accounting

Enclosures

29 **PU-399-02-183** Pages: 1

Letter to consluting service re contract

by Public Service Commission

07/03/2002 CC: Comm Legal PUD (3) Mike ALJ

APPROVED
DATE: 7-3-02
KME

MOTION

July 3, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission execute a $48,534 contract with Snavely King Majoros O'Connor & Lee, Inc. for consulting services in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase Application, Case No. PU-399-02-183.

MRD

28 **PU-399-02-183** Pages: 1

Motion

by Public Service Commission

07/03/2002 CC: Comm Legal PUD (3) Mike ALJ

CONTRACT

Administrator: Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505-0480
(701) 328-2400

Date: July 3, 2002

Anthony T. Clark	Susan E. Wefald	Leo M. Reinbold
Commissioner	**President**	**Commissioner**

Contractor		
Snavely King Majoros O'Connor & Lee, Inc.		
Name		
1220 L St NW Ste 410	Washington D C 20005	202-371-9156
Address	**City/State/Zip**	**Phone**
Charles W. King		President
Typed Name		**Title**
Signature		**Date**

Agreement Information

Contract No.:	PU-445-02
Start Date:	7-3-02
End Date:	6-30-03
Program Title:	PU-399-02-183

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(X) Cost Reimb. ( ) Unit Price
( ) Other

Budget Information

Cost Center:	7700
Services:	$48,534
Optional on-site review:	0
Expenses:	0
ID	52-0901220

Type of Contractor: ( ) Individual
(X) Corporation ( ) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other

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July 3, 2002

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1. Professional analysis and review of filing.
2. Prepare and conduct discovery.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff updated.
4. Prepare written testimony and provide an advanced copy to staff for review prior to submitting as a formal document.
5. Prepare written and oral testimony in rebuttal to testimony of other parties in the proceeding.
6. Testify at the hearing.
7. Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings.
8. After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed commission decision.

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Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

June 27, 2002

Dear Public Service Director:

Enclosed is an announcement of a Public Input Session that the Public Service Commission will conduct via interactive television on July 15, 2002, over the noon hour Central Daylight Time, at locations in the natural gas service area of Montana-Dakota Utilities Co. (MDU). The Commission requests this item be broadcast as a public service announcement during the period beginning July 1 through noon July 15, 2002. A copy of the Commission's official notice is enclosed.

The purpose of public input sessions is to solicit public comments and questions regarding MDU's application to increase rates for natural gas service, and provide an opportunity for customers to find out more about the case.

The Commission appreciates your assistance in this matter. If you have any questions, please contact me at 701-328-4076. Thank You.

Sincerely,

Sharon Helbling
Public Utilities Division

Enck

* See file ct 3 for copies of the recordings

27 **PU-399-02-183** Pages: 1

Cover letter re public service announcement & copies of the 6 by Public Service Commission

06/28/2002 CC: Comm Legal PUD (3) Mike ALJ .

Helbling, Sharon D.

From: Lein, Jerry R.
Sent: Friday, June 21, 2002 5:04 PM
To: Comm; Legal; PUD
Subject: Update - Public Service Announcements for MDU gas rate case

Commissioner Reinbold has an appointment with KFYR to produce 6 audio recordings on Thursday morning at a cost of $25 each. The recordings will be the same except for location information. We will need duplicates of each recording at $3 each.

Location	# of stations
Bismarck	8
Devils Lake	2
Dickinson	2
Jamestown	2
Minot	3
Williston	2
Total	20 dubs

We will need to mail the duplicates ourselves to each station. The cover letter should request the recordings be run as a public service announcement. The stations at each location are:

Name	RADIO	Address	City	State	Zip	SendBy
	E-mailAddress	FaxNumber				
News Director	KBMR/KQDY/KSSS	3500 E Rosser Ave	Bismarck	ND	58501-3398	
News Director	KCND Radio	1814 N 15th St	Bismarck	ND	58501-2094	e-mail
	ppr@pol.org	224-0555				
News Director	KFYR/KYYY Radio	PO Box 1738	Bismarck	ND	58502-1738	e-mail
	255-8244					
News Director	KLXX/KBYZ/KKCT	PO Box 1377	Bismarck	ND	58502-1377	
News Director	KXUM AM-FM Radio	7500 University Dr	Bismarck	ND	58504-9658	
News Director	KDLR/KDVL Radio	PO Box 190	Devils Lake	ND	58301-0190	
News Director	KZZY-FM Radio	PO Box 882	Devils Lake	ND	58301-0882	
	701-662-7564					
News Director	KDIX-AM Radio	119 2nd Ave W	Dickinson	ND	58601-5115	
News Director	KLTC-AM Radio	PO Box 1478	Dickinson	ND	58602-1478	
News Director	KZRX Radio	PO Box 1478	Dickinson	ND	58601-1478	Fax
	701-483-1959					
News Director	KQDJ/KYNU Radio	PO Box 1170	Jamestown	ND	58402-1170	
News Director	KSJB/KSJZ Radio	PO Box 5180	Jamestown	ND	58402-5180	
News Director	KLXX/KBYZ/KKCT	4303 Memorial Hwy	Mandan	ND	58554-4710	
News Director	KNDR-FM Radio	PO Box 516	Mandan	ND	58554-0516	
	663-2347					
News Director	KCJB/KYYX Radio	PO Box 1686	Minot	ND	58702-1686	
News Director	KHRT AM-FM Radio	PO Box 1210	Minot	ND	58702-1210	Fax
	701-852-8498					
News Director	KRRZ/KIZZ/KZPR	PO Box 10	Minot	ND	58702-0010	
	701-852-1390					
News Director	KDSR-FM Radio	PO Box 1487	Williston	ND	58802-1487	
News Director	KEYZ/KYYZ Radio	PO Box 2048	Williston	ND	58802-2048	
Jeff Alexander	KXMR Radio News	3500 E Rosser Ave	Bismarck	ND	58501	Fax
	222-1131(fax) 255-1234					

26 **PU-399-02-183** Pages: 1

Recordings of the public service announcement sent to radio stations by Public Service Commission

06/28/2002 CC: Comm Legal PUD (3) Mike ALJ .

This is Public Service Commissioner Leo M. Reinbold.

Your Public Service Commission will be holding public input meetings relating to MDU's filing requesting an increase in natural gas rates.

Everyone is invited.

Meetings are open to the public.

Come and speak your piece.

Meetings are scheduled at 12 Noon on July 15th, at the Vocational Technical Center, Room 228, at Bismarck State College.

That's 12 Noon on July 15th.

25 **PU-399-02-183** Pages: 7
Public Service Announcement
by Public Service Commission
06/27/2002 CC: Comm Legal PUD (3) Mike ALJ

This is Public Service Commissioner Leo M. Reinbold.

Your Public Service Commission will be holding public input meetings relating to MDU's filing requesting an increase in natural gas rates.

Everyone is invited.

Meetings are open to the public.

Come and speak your piece.

Meetings are scheduled at 12 Noon on July 15th, at the Administration Building, Room 172, at Lake Region State College, Devils Lake.

That's 12 Noon on July 15th.

This is Public Service Commissioner Leo M. Reinbold.

Your Public Service Commission will be holding public input meetings relating to MDU's filing requesting an increase in natural gas rates.

Everyone is invited.

Meetings are open to the public.

Come and speak your piece.

Meetings are scheduled at 12 Noon on July 15th, at the Crighton Building, Room 109, at Williston State College.

That's 12 Noon on July 15th.

This is Public Service Commissioner Leo M. Reinbold.

Your Public Service Commission will be holding public input meetings relating to MDU's filing requesting an increase in natural gas rates.

Everyone is invited.

Meetings are open to the public.

Come and speak your piece.

Meetings are scheduled at 12 Noon on July 15th, at the Administration Building, Room 158, at Minot State University.

That's 12 Noon on July 15th.

This is Public Service Commissioner Leo M. Reinbold.

Your Public Service Commission will be holding public input meetings relating to MDU's filing requesting an increase in natural gas rates.

Everyone is invited.

Meetings are open to the public.

Come and speak your piece.

Meetings are scheduled at 12 Noon on July 15th, at the Learning Resource Center, 3rd Floor, Room 320, at the North Dakota State Hospital, Jamestown.

That's 12 Noon on July 15th.

This is Public Service Commissioner Leo M. Reinbold.

Your Public Service Commission will be holding public input meetings relating to MDU's filing requesting an increase in natural gas rates.

Everyone is invited.

Meetings are open to the public.

Come and speak your piece.

Meetings are scheduled at 11:00 A.M. on July 15th, at the North Campus, Room 104, at Dickinson State College.

That's 11:00 A.M. on July 15th.

The North Dakota Public Service Commission has scheduled an informal public input session via interactive television on Monday, July 15, 2002 from 12:00 p.m. to 2:00 p.m. CDT throughout North Dakota to allow customers of Montana-Dakota Utilities Co. the opportunity to present their input regarding Montana-Dakota's application to increase their natural gas rates.

Montana-Dakota has asked for an overall increase of 4.1 percent which would produce approximately $2.8 million in additional annual revenues if approved by the commission.

The primary reason for the rate filing is increased operation and maintenance costs, depreciation costs and taxes, in spite of the Company's efforts to control and maintain these costs levels.

If the increase is granted in full, the average residential customer using 110 decatherms (dk) annually would see an increase of approximately $24 each year. A firm general service customer using 300 dk annually would pay approximately $55 more per year. Proposed rate schedules and a comparison of the present and proposed rates are on file and can be examined at the Montana-Dakota office noted on your bill.

You are invited to participate in the public input session on

JULY 15, 2002 @ 12:00 CDT

at the following locations:

- **BISMARCK**
  Vocational Technical Center, Room 228
  Bismarck State College
- **DICKINSON**
  North Campus, Room 104
  Dickinson State University
- **DEVILS LAKE**
  Administration Building, Room 172
  Lake Region State College
- **WILLISTON**
  Crighton Building, Room 109
  Williston State College
- **MINOT**
  Administration Building, Room 158
  Minot State University
- **JAMESTOWN**
  Learning Resource Center
  3rd Floor, Room 320
  2605 Circle Drive

1 2:00 Noon

For more information, please contact the North Dakota Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-4200; or Relay North Dakota 1-800-366-6888 TTY.

Public input sessions provide a chance for customers to learn more about the rate case issues. Customers are encouraged to make comments, suggestions and ask questions regarding Montana-Dakota's application.

Affidavit of Publication

JUN 19 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

State of North Dakota)
)
County of Burleigh)

Laurie Thiel, being duly sworn, state as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of:
MDU Public Input, 1 time(s)
as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Laurie Thiel

Subscribed and sworn to before me this 17th day of June A.D. 2002.

Laurie Schaffer

LAURIE SCHAFFER
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires DEC. 1, 2005

24 **PU-399-02-183** Pages: 1

Affidavit of Publication

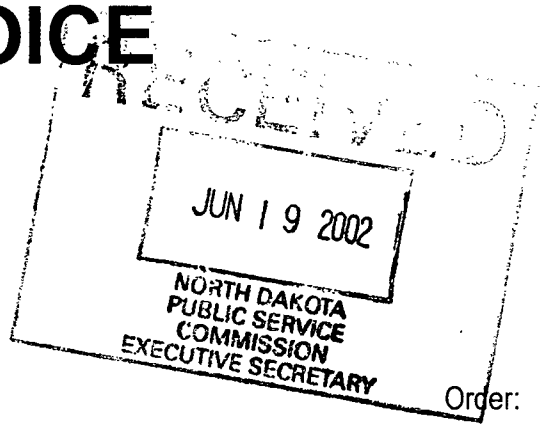
by North Dakota Advertising Service, Inc.

06/19/2002 CC: Comm Legal PUD (3) Mike ALJ

North Dakota Advertising Service, Inc.

1435 Interstate Loop • Bismarck, ND 58501-0567 • PHONE (701) 223-6397 • FAX (701) 223-8185 • www.ndna.com

INVOICE



Date: 06/18/2002

Page: 1

To:
JON H. MIELKE
PUBLIC SERVICE COMMISSION
STATE CAPITOL
BISMARCK ND 58505

Client: Public Service Commission

Order: 02062PP2

Newspaper	Date	Inches	Page#	Rate	Amount
Bismarck Tribune	MDU... Pub 06/12/2002	1.00	[Special]	66.49	66.49
Devils Lake Daily Journal	MDU... Pub 06/12/2002	1.00	[Special]	67.26	67.26
Dickinson Press	MDU... Pub 06/12/2002	1.00	[Special]	64.48	64.48
Grand Forks Herald	MDU... Pub 06/13/2002	1.00	[Special]	64.66	64.66
Jamestown Sun	MDU... Pub 06/12/2002	1.00	[Special]	61.00	61.00
Minot Daily News	MDU... Pub 06/12/2002	1.00	[Special]	52.92	52.92
Valley City Times-Record	MDU... Pub 06/12/2002	1.00	[Special]	64.48	64.48
Williston Herald	MDU... Pub 06/12/2002	1.00	[Special]	73.92	73.92
			*** ADVERTISING TOTAL		515.21
			*** TOTAL DUE		515.21

24 **PU-399-02-183** Pages: 1

Affidavit of Publication

by North Dakota Advertising Service, Inc.

06/19/2002 CC: Comm Legal PUD (3) Mike ALJ .

This invoice is due and payable upon receipt. Unpaid items over 30 days from invoice date are subject to a finance charge. The finance charge is computed by a periodic rate of 1 3/4 percent per month (or a minimum charge of 50 cents for balances of under $50), which is an annual percentage rate of 21 percent.
Total unpaid balance may be paid at any time.

Please pay from this invoice — No statement will be sent. Return duplicate with remittance to North Dakota Advertising Service, Inc.

Notice Of Hearing Of Public Input Sessions,
And Notice Of Intervention Deadline
June 5, 2002
Case No. PU-399-02-183

Bismarck	6-12
Devils Lake	6-12
Dickinson	6-12
Fargo	
Grand Forks	6-13
Jamestown	6-12
Minot	6-12
Valley City	
Walpeton	
Williston	6-12

OFFICE OF ADMINISTRATIVE HEARINGS

STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state.nd.us
www.state.nd.us/oah

June 14, 2002

RECEIVED
JUN 17 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Mr. William Binek
Hearing Administrator
Public Service Commission
600 E. Boulevard Avenue – Dept. 408
Bismarck, ND 58505-0480

Dear Mr. Binek:

Thank you for your June 11, 2002, request of the designation of an administrative law judge from the Office of Administrative Hearings to conduct a hearing in the matter of Montana-Dakota Utilities Co. (PU-399-02-183). I hereby designate myself to be assigned as a administrative law judge to conduct the hearing in regard to this matter. Because the administrative law judge will not be making recommended findings of fact and conclusions of law, or issuing a recommended order, the person or persons who will actually be making the final administrative decision in regard to this matter (i.e., commission) must actually be in attendance at the hearing.

Please send all additional relevant documents in regard to this matter (correspondence, and other pleadings and documents) to the designated administrative law judge in care of the Office of Administrative Hearings, 1707 North 9th Street, Bismarck, North Dakota 58501-1882. The hearing is scheduled for October 7 – 8, 2002, beginning at 9:00 a.m., in the Commission Hearing Room, State Capitol, 600 E. Boulevard Avenue, Bismarck, North Dakota.

Sincerely,

Allen C. Hoberg
Director

ACH:ljc

cc: Don Ball

23 PU-399-02-183 Pages: 1
Allen Hoberg designated ALJ
by Office of Administrative Hearings
06/17/2002 CC: Comm Legal PUD (3) Mike ALJ

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

RECEIVED
JUN 17 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

June 13, 2002

Mr. William W. Binek
Hearing Administrator
North Dakota Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

Re: Request for Court Reporter
Montana-Dakota Utilities Co.
Natural Gas Rate Increase Application
Case No. PU-399-02-183

Dear Mr. Binek:

In response to your letter dated June 11, 2002, Montana-Dakota Utilities Co. would like a court reporter present at the hearing scheduled in the above referenced case for October 7, 2002, beginning at 9:00 AM, in the Commission Hearing Room.

Please make the necessary arrangements and advise.

Sincerely,

Donald R. Ball
Director of Regulatory Affairs

cc: D. Schulz
W. P. Pearce

22 PU-399-02-183 Pages: 1

Request for court reporter to be present at formal hearing on 10/7/02
by Montana-Dakota Utilities Co., a Division of MDU Re

06/17/2002 CC: Comm Legal PUD (3) Mike ALJ

Public Service Commission
State of North Dakota

RECEIVED
JUN 17 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

Memo

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

To: Commissioners and Illona

From: Mike Diller & Bill Binek Mike Diller

Date: June 17, 2002

Re: Bid Proposals for MDU's Gas Case (PU-399-02-183)
Administrative Agenda Item for June 19, 2002

At the direction of the commission, staff requested bid proposals to handle the staff advocacy portion of MDU's electric rate increase application. Specifically, staff requested price quotes for developing revenue requirements, cost of capital, depreciation and rate design.

Staff received bids from six consulting firms ranging in price from $48,534 to $170,750. Because price is an important factor in staff's analysis of the bid proposals, all but Snavely King and Larkin & Associates were effectively eliminated from consideration.

Both remaining candidates bid within $966 of each other and has provided good service to the commission in the past. Staff believes that both firms would be effective in representing advocacy staff.

All things being equal, Snavely King out bid Larkin & Associates. In addition, staff believes there may be some carry-over value in Snavely King's recent involvement in staff's rate complaint case against MDU's electric operations.

Staff recommends that the commission enter into a contract with Snavely King to provide the commission with a full rate case investigation and testimony. The valuation fund currently has a balance of about $94,000 for these types of cases.

Following is a summary of the individual component bids:

	Snavely	Larkin
Revenue Requirements	$15,292	$22,996
Cost of Capital	9,014	6,626
Rate Design	6,136	7,016
Depreciation Expense	18,092	12,862
Total Bid	$48,534	$49.500

21 **PU-399-02-183** Pages: 1

Staff memo recommending Snavely King as advocacy staff consultant by Public Service Commission by Mike Diller

06/17/2002 CC: Comm Legal PUD (3) Mike ALJ .

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

June 11, 2002

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

Mr. Don Ball
Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

Re: Request for Court Reporter
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application
Case No. PU-399-02-183

Dear Mr. Ball:

The hearing in the above case has been scheduled for October 7, 2002, beginning at 9:00 a.m., in the Commission Hearing Room. The Commission will tape record the hearing. If MDU would like a court reporter present at the hearing please notify the Commission in writing within ten days of receipt of this letter and our office will make the necessary arrangements.

The Commission has a contract with the following court-reporting service:

Emineth & Associates
P. O. Box 2655
Bismarck, ND 58502-2655
Telephone: 701-255-3513
Fax: 701-255-6079

Montana-Dakota Utilities would pay costs associated with the court-reporting service (i.e. appearance fee, transcript of hearing), and Emineth & Associates will bill for its services as directed.

If you have any questions, please contact us.

Sincerely,

William W. Binek
Hearing Administrator

20 **PU-399-02-183** Pages: 1

Letter re MDU re court reporter service for hearing
by Public Service Commission

06/11/2002 CC: Comm Legal PUD (3) Mike ALJ .

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

June 11, 2002

Mr. Allen C. Hoberg
Office of Administrative Hearings
1707 North 9th Street, Lower Level
Bismarck, ND 58501

Re: Case No. PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Dear Mr. Hoberg:

Enclosed is a request for an administrative law judge in the above case. The Commission has scheduled a hearing for October 7, 2002, beginning at 9 a.m. (CST) in the Commission's Hearing Room, 12th Floor, State Capitol, Bismarck. The administrative law judge will serve as a procedural law judge, a court reporter may be present, and the hearing will be tape recorded. A copy of the case is enclosed.

Please provide the Commission with a copy of any filings issued by your office in this matter.

If you have any questions, please contact me. Thank you.

Sincerely,

William W. Binek
Hearing Administrator

/sls
Enclosure

c: Don Ball, MDU

19 **PU-399-02-183** Pages: 2

Request for ALJ

by Public Service Commission

06/11/2002 CC: Comm Legal PUD (3) Mike ALJ .

REQUEST FOR ADMINISTRATIVE LAW JUDGE--APPEAL, APPLICATION, OR PETITION

NORTH DAKOTA OFFICE OF ADMINISTRATIVE HEARINGS

SFN 17819 (Rev. 03-2001)

Name of Agency, Board, or Commission
Public Service Commission

The above named agency, board, or commission requests designation of an administrative law judge from the Office of Administrative Hearings for the Montana-Dakota Utilities Co., Natural Gas Rate Increase Application, Case No. PU-399-02-183.

Hearing is set for October 7 & 8, 2002, beginning at 9 a.m., Commission Hearing Room, 12th floor, State Capitol.

(e.g., application of [name], appeal of [name], petition of [name]). Authority for the administrative action is found in Title 49 (North Dakota Century Code and/or North Dakota Administrative Code).

Please attach related documents and correspondence.

The administrative action is more fully described as follows:

It requests designation of an administrative law judge (please check one):

- ☐ **To conduct the hearing and issue recommended findings of fact, conclusions of law, and order.**
- ☑ **To serve as a procedural administrative law judge only (no recommended decision). The agency head will be present at the hearing as required by NDCC 54-57-04(6).**
- ☐ **To conduct the hearing, issue findings of fact, conclusions of law, and a final order.**

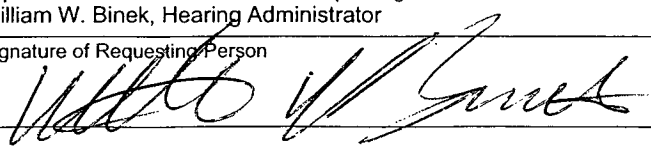
PLEASE MAKE A REQUEST FOR AN ADMINISTRATIVE LAW JUDGE AT LEAST ONE MONTH BEFORE THE HEARING.

Please list parties, including the agency if it is a Party, and Representation [attorney (or other)] if known, or Agency Contact: (Attach separate list if necessary.)

AGENCY Public Service Commission	Address 600 E Blvd. Ave., Dept. 408, Bismarck	Telephone Number 328-2400
Representation William W. Binek, Chief Counsel	Address Same as above	Telephone Number 328-4088
PARTY Montana-Dakota Utilities Co.	Address 400 N 4th Street, Bismarck, ND 58501	Telephone Number 222-7900
Representation Contact Person: Don Ball	Address Same as above	Telephone Number
PARTY	Address	Telephone Number
Representation	Address	Telephone Number

Additional Comments
Hearing will be tape recorded. Court reporter may be present.

(For agencies required to use OAH, notice of hearing will be issued by the administrative law judge, unless a procedural administrative law judge is requested. Other requesting agencies and agencies requesting a procedural administrative law judge should first contact OAH about scheduling a hearing. If notice has already been issued, attach a copy of the notice.)

Typed or Printed Name and Title of Requesting Person William W. Binek, Hearing Administrator	Date 6-11-02
Signature of Requesting Person X 	Telephone Number 328-4088

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **6th day of June, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

> **Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline**

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 1940 0005 3426 8772

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **6th day of June, 2002**.

Sandra L. Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **6th day of June, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

> **Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline**

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **6th day of June, 2002**.

Sandra L. Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

akemp@tminc.com
Ann-Marie Kemp

ccano@mh.com
Craig Cano
Gas Utility Report
1200 G St NW Ste 1100
Washington DC 20005

Mark.Hanson@grandforks.af.mil
Mark Hanson
Grand Forks Air Force Base
319 ARW/JA
460 Steen Blvd Ste 201
Grand Forks ND 58205

inland@btigate.com

Inland Oil & Gas Corp
PO Box 1313
Bismarck ND 58502-1313

Karyn Grass
IPAMS
6620 Denver Club Bldg
518 17th ST
Denver CO 80202-4167

jason_gustafson@bobcat.com
Jason Gustafson
Melroe Company
P O Box 128
Gwinner ND 58040-0128

craig_scott@bobcat.com
Craig Scott
Melroe Company
P O Box 128
Gwinner ND 58040-0128

tom.hopgood@mduresources.com
Tom Hopgood
Montana-Dakota Utilities Co

balld@mdu.mdures.com
Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

collinsk@mdu.mdures.com
Karen Collins
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

dave.sederquist@xcelenergy.com
Dave Sederquist
Northern States Power Company
414 Nicollet Mall
Minneapolis MN 55401

wpp@pearce-durick.com
William Pearce
Pearce & Durick Attorneys
PO Box 400
Bismarck ND 58502-0400

mdickers@state.nd.us
Marcy Dickerson
State Tax Department
State Capitol
Bismarck ND 58505

F James Moriarty
2333 Plum Grove Dr
O'Fallon MO 63366

Steven Tom
2498 59th St
St Anthony ND 58566-9640

Peter Hoff
Arveson Donoho Lundeen Etc
125 S Mill St
Fergus Falls MN 56537

Will Kaul
Cooperative Power Association
P O Box 800
Elk River MN 55330-0800

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Frank Morehouse
Great Plains Natural Gas Co
PO Box 176
Fergus Falls MN 56548-0176

Jay Casler
INDEPTH DATA INC
211 N Robinson Ave Ste S-1500
Oklahoma City OK 73102-7101

Connie Zimmerman
Inoco Inc
Box 177C Rte 4
Williston ND 58801

KBMR AM-KQDY FM
3500 E Rosser Ave
Bismarck ND 58501

KBMW-AM
PO Box 1115
Wahpeton ND 58074-1115

KDAK AM
Box 50
Carrington ND 58421-0050

Rod Kleinjan
KDIX AM Radio
119 2nd Ave W
Dickinson ND 58601-5115

KDLR AM-FM
Box 190
Devils Lake ND 58301-0190

KEYZ-AM
PO Box 2048
Williston ND 58802-2048

Jeff Alexander
KFYR-AM Radio
PO Box 1738
Bismarck ND 58502-1738

KHRT AM
PO Box 1210
Minot ND 58702-1210

KMOT TV
Box 1120
Minot ND 58702-1120

KNDK-AM
HCR 5 Box 9
Langdon ND 58249

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

KOVC-AM
PO Box 994
Valley City ND 58072-0994

KSJB AM and KSJZ FM Radio
PO Box 5180
Jamestown ND 58402-5180

KTGO-AM
Box 457
Tioga ND 58852-0457

KUMV-TV
PO Box 1287
Williston ND 58802-1287

News Director
KXMA-TV
Drawer B
Dickinson ND 58602

KXMB TV
Box 1617
Bismarck ND 58502-1617

KXMC TV
Box 1686
Minot ND 58701-1686

KXMD-TV
PO Box 790
Williston ND 58802-0790

KXPO AM & FM Radio
856 W 12 St
Grafton ND 58237

C W Fox
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Ron Tipton
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Scott Speaker
Natural Gas Week
1401 New York Ave NW Ste 500
Washington DC 20005-2150

Harlan Fuglesten
ND Association of RECs
PO Box 727
Mandan ND 58554-0727

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Helbling, Sharon D.

From: Helbling, Sharon D.
Sent: Thursday, June 06, 2002 11:07 AM
To: ndna (E-mail)
Subject: MDU Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline, Case No. PU-399-02-183

Colleen
North Dakota Newspaper Association

Colleen,

Here's the corrected Notice. Please publish as I noted in my original e-mail earlier this morning. Call me if you have any questions.

Thank you.

Sharon Helbling
Public Utilities Division

6-5-02 Notice of Hearing.doc

Helbling, Sharon D.

From: Helbling, Sharon D.
Sent: Thursday, June 06, 2002 10:46 AM
To: ndna (E-mail)
Subject: MDU Notice of Hearing, Case No. PU-399-02-183

Colleen,

Don't publish this one yet. I guess there's something wrong and we have to correct it. I'll send you a corrected one.

Thanks.

Sharon

Helbling, Sharon D.

From: Helbling, Sharon D.
Sent: Thursday, June 06, 2002 9:42 AM
To: ndna (E-mail)
Subject: Attached Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline, Case No. PU-399-02-183

Colleen
North Dakota Newspaper Association

Colleen,

Please have the attached Notice published as a legal publication and run it as a "News Item Only" article in the next issue of the following newspapers:

Bismarck Tribune
The Dickinson Press
Minot Daily News
Williston Daily Herald
Devils Lake Journal
Jamestown Sun
Valley City Times-Record
Grand Forks Herald

Please send the bill to the Public Service Commission along with a tear sheet for billing purposes.

If you have any questions, please call me at 328-4076. Thank you.

Sharon Helbling
Public Utilities Division

6-5-02 Notice of Hearing.doc

APPROVED
DATE: 6-5-02
KMF

MOTION

June 5, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission issue a Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase Application, Case No. PU-399-02-183.

sdh

17 PU-399-02-183 Pages: 1
Motion
by Public Service Commission
06/05/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

NOTICE OF HEARING, NOTICE OF PUBLIC INPUT SESSIONS, AND NOTICE OF INTERVENTION DEADLINE

June 5, 2002

On April 12, 2002, Montana Dakota Utilities Co. (MDU) filed an application to increase its rates for natural gas service by an amount sufficient to provide increased total annual revenue of $2,844,132. MDU proposes to increase rates for residential and firm general service by 4.6% while decreasing small interruptible service by 4.1%. MDU proposes no increase in rates for service to large interruptible customers or the Minot air force base. MDU estimates the proposed increase for a residential customer would average about $24 per year.

MDU further proposes to redefine billing components to better align costs with rates for service. MDU alleges these changes would provide stability during periods of abnormal weather while making its bills more understandable. The proposed rate changes do not affect the cost of purchased gas, which is separately recovered through the purchased gas adjustment billing provision.

A **public hearing** on this matter will be held beginning **October 7, 2002 at 9 a.m. (CST)** in the Commission hearing room, State Capitol, 12th Floor, Bismarck, North Dakota 58505. Anyone wishing to become a party to this proceeding must file a Petition to Intervene by September 9, 2002. Issues to be considered in this matter include:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

Public input sessions will be held via interactive television on **July 15, 2002 at 12 Noon (CDT)** at locations set forth below. Members of the public are invited to appear and participate in the informal discussions. The meetings are not considered part of the technical hearing and the discussion at the meetings will not become part of the evidence reviewed by the Commission in making its decision. The discussion will, however, aid the Commission and its staff in identifying areas of concern to the members of the public.

Bismarck State College **Vocational Technical Ctr Rm 228** **1200 College Dr** **Bismarck ND**	**Lake Region State College** **Administration Bldg Rm 172** **Devils Lake ND**
Dickinson State University **North Campus Rm 104** **1679 6th Ave W** **Dickinson, ND**	**North Dakota State Hospital** **Learning Resource Ctr 3rd Fl Rm 320** **2605 Circle Dr** **Jamestown ND**
Minot State University **Administration Bldg Rm 158** **Minot ND**	**Williston State College** **Crighton Bldg Rm 109** **Williston ND**

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400 or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify, Jon H. Mielke, Executive Secretary, at least 24 hours prior.

PUBLIC SERVICE COMMISSION

Anthony T. Clark
Commissioner

Susan E. Wefald
President

Leo M. Reinbold
Commissioner

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **10th day of May, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and containing a photocopy of:

Request for Proposal

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2510 0005 8654 8730

Sharon Helbling further deposes and says that on the **10th day of May, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope by regular mail, with postage fully prepaid, securely sealed, each containing a photocopy of the same.

Docket Nos.
10-15- response to
request for Proposals -

PU-399-02-183 Pages: 3

Affidavit of Service

by Public Service Commission

05/10/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **10th day of May, 2002**.

Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **10th day of May, 2002**, she sent by E-Mail or deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Request for Proposal

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **10th day of May, 2002**.

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

Sandra L Scott
Notary Public

SEAL

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Business Dept
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Finance Dept
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APPROVED

DATE: 5-08-02

KMF

MOTION

May 8, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission issue a Request for Proposal for consulting services in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application, Case No. PU-399-02-183.

MRD

8 **PU-399-02-183** Pages: 1

Motion

by Public Service Commission

05/08/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

REQUEST FOR PROPOSAL

To: Potential Bidders

From: Mike Diller
Director of Accounting

Date: May 10, 2002

Re: Request for Proposal, Case No. PU-399-02-183

The North Dakota Public Service Commission is requesting written proposals from selected firms to assist commission staff in its investigation of Montana-Dakota Utilities Co.'s (MDU's) gas rate increase request, including cost of capital, cost of service and rate design. The completion date for the investigation and written testimony is August 30, 2002. The technical hearing will be held on October 7 & 8, 2002.

The specific purpose is to investigate, analyze and provide testimony regarding the fairness and reasonableness of MDU's proposed gas rates. To accomplish this, the commission is requesting proposals for investigation, analysis and testimony to include the following areas:

1. The appropriate level of investment.
2. The appropriate cost of capital.
3. The appropriate cost of service.
4. The appropriate rate design.
5. Depreciation study.

See Attachment for additional discussion and direction on each of these issues.

Consulting duties include:

1. Professional analysis and review of the filing.

2. Prepare and conduct discovery as necessary.

3. Monthly progress reports of discovery, conclusions and recommendations.

4. Prepare and file written testimony.

5. Provide oral testimony.

6. Assist staff in preparing cross-examination of the witnesses of other parties to the proceeding.

7. Assist staff in the preparation of proposed findings of fact.

The staff will select firms to be interviewed. Selection will be based on an evaluation using the following criteria:

1. Quality of written proposal (5 points).

2. Capability, including personnel qualifications, specialized experience, training, education, and performance record (20 points).

3. Understanding of the project (20 points).

4. Proposed work approach (10 points).

5. Price (45 points):
   a. Lowest to 120% of lowest bid = 45 points
   b. 121% to 130% of lowest bid = 44 points
   c. 131% to 140% of lowest bid = 42 points
   d. 141% to 150% of lowest bid = 38 points
   e. 151% to 160% of lowest bid = 32 points
   f. 161% to 170% of lowest bid = 24 points
   g. 171% to 180% of lowest bid = 14 points
   h. 181% to 190% of lowest bid = 2 points
   i. 191% and over of lowest bid = 0 points

The written proposal should include a fixed price. The **proposal may include separate bids for each desired issue or a combined price for two or more issues.** Resumes of those professionals directly providing services should be included along with examples of any past work similar to that required in this project. In addition, those who have not previously contracted should provide at least three client references.

After the interview process, staff will make recommendations to the commission. The commission may consider hiring a consultant to perform any one of the identified tasks or portions of the identified tasks. The commission has the right to enter into competitive negotiations with qualified bidders for the purpose of selecting a consultant to perform all or a portion of the identified work. The commission retains the right to reject any and all proposals.

The successful contractor will be required to comply with all applicable Equal Employment Opportunity laws and regulations. All proposals shall include certification that they comply with applicable provisions of the Americans with Disabilities Act of 1991. A signed "Conflict of Interest Disclaimer" must accompany all proposals and will be made part of the final contract.

Written proposals from qualified consultants will be accepted until the close of business May 30, 2002.

Submit an original and five copies of proposals to:

Mike Diller, Director of Accounting
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480
Telephone No. (701) 328-4079

Sincerely,

Mike Diller

Mike Diller

Attachment

1. The appropriate level of investment in North Dakota.

The rate base determination is not nearly as critical in terms of rate impact as is establishing the appropriate cost of service. Therefore, work in this area should be limited in scope and should primarily rely on a review of the last rate case and historical comparisons. Annual reports are filed with the commission and include all rate base components. MDU does not seek a return on cash working capital in this case. Staff calculated cash working capital in MDU's last rate decrease case and the resulting impact to rates was minimal. Therefore, rate base will not require a cash working capital calculation.

2. The appropriate cost of capital.

MDU's cost of capital includes long-term debt, preferred equity and common equity. Because MDU's cost of debt is high, the capital structure is not that critical to rates. On April 24, 2002, the commission issued a rate reduction order for MDU's electric operations and extensive testimony and information is readily available from that case. In the electric reduction case, staff argued for a lower cost of debt using an accounting approach rather than a yield-to-maturity calculation. The commission ordered in favor of MDU and staff does not anticipate making another argument in this case for a lower cost of long-term debt. As is often the case, the critical element of cost of capital is the return on equity component. MDU's witness filed testimony supporting a return on equity of 13.25% using DCF analyses.

3. The appropriate cost of service.

In 2001, 80% of MDU's revenues were spent on the cost of gas. Therefore, a critical element of cost of service is the appropriate level of weather-normalized sales. The cost of service portion will also require a strong review of other operating and maintenance expenses.

4. The appropriate rate design.

In its application to increase rates, MDU argues for increasing the residential monthly basic service charge from $6.50 to $11.70. In the event the commission does not accept the basic service charge increase, MDU argues for the inclusion of a weather normalization adjustment.

5. Depreciation study.

MDU's last depreciation study was conduced in the early 90's and the commission may be interested in having a depreciation study completed for this proceeding.

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
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web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

April 25, 2002

Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Dear Mr. Ball:

On April 24, 2002, the Commission approved Montana-Dakota Utilities Co.'s natural gas purchased gas adjustment for May 2002, Case No. PU-399-02-179, and suspended the tariffs filed with the Natural Gas Rate Increase application, Case No. PU-399-02-183.

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

Enclosure

6 **PU-399-02-183** Pages: 1

Letter re suspension of tariff

by Public Service Commission

04/26/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

APPROVED

DATE: 4-24-02
KME

MOTION

April 24, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission suspend Montana-Dakota Utilities Co.'s rates filed with its Natural Gas Rate Increase application in Case No. PU-399-02-183.

Sdh

5 **PU-399-02-183** Pages: 1

Motion suspending tariff

by Public Service Commission

04/24/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Public Service Commission

Receipt of Paymer

Received: 4/15/2002 Check# 940293 for $50.00 Receipt# 4844

Subject: Gas Rate Application **Docket # PU-399-02-183**

Montana-Dakota Utilities Co., a Division of MDU Resources
400 N 4th Street
Bismarck ND 58501

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

RECEIVED
APR 12 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

April 12, 2002

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505

Re: General Natural Gas Rate Application
Case No. PU-399-02-____

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits its application for approval to increase its rates for natural gas service. Montana-Dakota encloses herein an Application with Appendices A and B, Testimony and Exhibits and supporting Statements that document the need for this request to increase rates for natural gas service. This filing is made in accordance with Title 49 of the North Dakota Century Code and the rules and regulations promulgated by the North Dakota Public Service Commission.

The Company's need for additional revenues results from increases in expenses such as: operating and maintenance expenses, depreciation, and taxes other than income taxes. The increase will also provide Montana-Dakota with a higher return on equity.

In spite of cost control efforts, cost-of-service increases have caused current rates to be inadequate in compensating the company for operating its North Dakota natural gas distribution system. Montana-Dakota's last general rate increase in North Dakota was in 1994. Since then, the Consumer Price Index has increased by about 20 percentage points.

Montana-Dakota proposes a total annual increase of $2,844,132, or 4.1%, based on a 2003 projected test year. The proposed change in rates will affect customer classes follows: Residential, 4.6%; Firm General Service, 4.6%; Air Force, 0%; Small Interruptible, (4.1%); and, Large Interruptible, 0%. The proposed increase for a residential customer will average about $2.00 per month or about $24.00 per year.

As reflected in the application, Montana-Dakota proposes to redefine the components of the gas bill and thereby better align its cost of service with its rates. The changes to the rate form will provide a measure of stability for

EXHIBIT
TAKEN
1-3

4 PU-399-02-183 Pages. 4
Cover letter re Application
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 1-3
04/12/2002 CC: Comm Legal Illona, Pat, Jerry Mike

customers during periods of abnormal weather and provide customers with an understandable rate and bill, while providing Montana-Dakota with enhanced fixed cost recovery.

The proposed rate changes do not affect the recovery of the cost of purchased gas, which is separately reflected in retail rates (and recovered monthly) through the Purchased Gas Cost Adjustment. Montana-Dakota proposes to reflect all gas costs separately using the proposed rate form change referenced above. The company feels this change will allow customers to readily identify the total portion of their bill related to the cost of gas as well as the portion related to Montana-Dakota's distribution service.

With this filing, Montana-Dakota also proposes to own all service lines on a prospective basis. This change will apply to all new and replacement service lines subject to appropriate extension policy provisions. It will eliminate the need for zone rates and will provide for a uniform rate and service line policy on a statewide basis.

Please refer all inquiries regarding this filing to:

Mr. Donald R. Ball
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

Also, please send copies of all written inquiries, correspondence and pleading to:

Mr. Douglas W. Schulz
Senior Attorney
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Mr. William P. Pearce
Attorney at Law
Pearce & Durick
314 E. Thayer Avenue
P.O. Box 400
Bismarck, ND 58502

The original and seven (7) copies of this Letter of Transmittal, Application and Appendices, Testimony and Exhibits, and Statements are hereby filed with the North Dakota Public Service Commission.

A report of tariff change reflecting Commission data requirements regarding filings is attached hereto.

Montana-Dakota also herewith submits a check for $50.00 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code.

Montana-Dakota respectfully requests that this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball
Director of Regulatory Affairs

Attachment
cc: C.W. Fox
D.W. Schulz
W.P. Pearce

North Dakota Report of Tariff Schedule Change

Case No. PU-399-02-____

Name of Utility: Montana-Dakota Utilities Co.

Address Main Office: 400 North Fourth Street, Bismarck ND 58501

NEW TARIFF DESIGNATION

Table of Contents	P.S.C. Tariff Volume 7	Sheet No. 1
Communities Served	P.S.C. Tariff Volume 7	Sheet No. 2
Rate Summary	P.S.C. Tariff Volume 7	Sheet No. 3-3.1
Residential Gas Service Rate 60	P.S.C. Tariff Volume 7	Sheet No. 4
Air Force Rate 64	P.S.C. Tariff Volume 7	Sheet No. 7-7.1
Firm General Gas Service Rate 70	P.S.C. Tariff Volume 7	Sheet No. 13
Small Interruptible Gas Service Rate 71	P.S.C. Tariff Volume 7	Sheet No. 14-14.2
Optional Seasonal General Gas Service Rate 72	P.S.C. Tariff Volume 7	Sheet No. 15-15.1
Transportation Service Rates 81 and 82	P.S.C. Tariff Volume 7	Sheet No. 24-24.9
Large Interruptible General Gas Service Rate 85	P.S.C. Tariff Volume 7	Sheet No. 27-27.2
Purchased Gas Cost Adjustment Rate 88	P.S.C. Tariff Volume 7	Sheet No. 30-30.5
Residential Propane Service Rate 90	P.S.C. Tariff Volume 7	Sheet No. 32
Firm General Propane Service Rate 92	P.S.C. Tariff Volume 7	Sheet No. 34-34.1
Purchased Propane Cost Adjustment Rate 99	P.S.C. Tariff Volume 7	Sheet No. 41-41.2
General Provisions Rate 100	P.S.C. Tariff Volume 7	Sheet No. 42-42.18
Residential Rate for Regular Employees Rate 102	P.S.C. Tariff Volume 7	Sheet No. 44
Interruptible Gas Extension Policy Rate 119	P.S.C. Tariff Volume 7	Sheet No. 61-61.1
Firm Gas Extension Policy Rate 120	P.S.C. Tariff Volume 7	Sheet No. 62-62.5
New Installation, Replacement, Relocation	P.S.C. Tariff Volume	Sheet No.
& Repair of Gas Service Lines Rate 124	P.S.C. Tariff Volume 7	Sheet No. 66

Change: Rates

(State part of tariff affected by change, such as: applicability, availability, rates, etc.)

Reason for Change: Increase in cost of providing natural gas service.

Approximate annual reduction in revenue ..... N/A

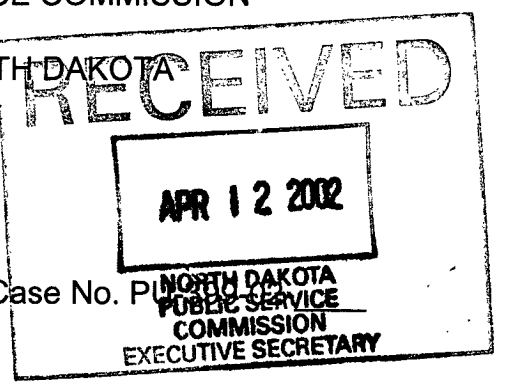
Approximate annual increase in revenue $2,844,132

Points Affected	Estimated number of customers whose cost of service will be:		
	Reduced	Increased	Unchanged
All		83,500	

Montana-Dakota Utilities Co.
Donald R. Ball
Director of Regulatory Affairs

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA



In the Matter of the Application of	)	
MONTANA-DAKOTA UTILITIES CO., a	)	
Division of MDU Resources Group, Inc.,	)	Case No. PU-399-02-
for Authority to Establish Increased	)	
Rates for Natural Gas Service	)	

* * * *

APPLICATION

COMES NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., the Applicant in the above-entitled proceeding (hereafter "Montana-Dakota" or "Applicant"), and respectfully alleges as follows:

I.

That Montana-Dakota, a Division of MDU Resources Group, Inc., is a Delaware corporation duly authorized to do business in the State of North Dakota as a foreign corporation, and that it is doing business in the State of North Dakota as a public utility.

II.

That the Certificate of Incorporation and Amendments thereto have previously been filed with the North Dakota Public Service Commission (PSC or Commission) and reference thereto is hereby made, and such Certificate and Amendments are hereby incorporated herein by reference as though fully set forth herein.

3 PU-399-02-183 Pages: 218
Application
by Montana-Dakota Utilities Co., a Division of MDU R
04/12/2002 CC: Comm Legal Illona, Pat, Jerry Mike

III.

That Applicant's full name and post office address are:

Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, North Dakota 58501

IV.

That the following described rate schedules presently on file with and approved by the Commission are attached hereto as Appendix A.

Volume No. 6

2nd Revised Sheet No. 1	Table of Contents
1st Revised Sheet No. 2	Communities Served
2nd Revised Sheet No. 3	Residential Gas Service Rate 60
2nd Revised Sheet No. 5	Optional Seasonal Residential Gas Service Rate 62
Original Sheet No. 5.1	Optional Seasonal Residential Gas Service Rate 62
Original Sheet Nos. 7-7.1	Air Force Rate 64
2nd Revised Sheet No. 13	Firm General Gas Service Rate 70
1st Revised Sheet No. 14	Small Interruptible General Gas Service Rate 71
Original Sheet No. 14.1-14.2	Small Interruptible General Gas Service Rate 71
2nd Revised Sheet No. 15	Optional Seasonal General Gas Service Rate 72
Original Sheet No. 15.1	Optional Seasonal General Gas Service Rate 72
1st Revised Sheet Nos. 24	Transportation Service Rates 81, 82, 84
Original Sheet Nos. 24.1-24.5	Transportation Service Rates 81, 82, 84
1st Revised Sheet Nos. 24.6-24.8	Transportation Service Rates 81, 82, 84

1st Revised Sheet No. 27	Large Interruptible General Gas Service Rate 85
Original Sheet Nos. 27.1-27.2	Large Interruptible General Gas Service Rate 85
4th Revised Sheet No. 30	Purchased Gas Cost Adjustment Rate 88
1st Revised Sheet No. 30.1	Purchased Gas Cost Adjustment Rate 88
2nd Revised Sheet Nos. 30.2-30.5	Purchased Gas Cost Adjustment Rate 88
Original Sheet No. 32	Residential Propane Service Rate 90
Original Sheet No. 34	Firm General Propane Service Rate 92
50th Revised Sheet No. 41	Purchased Propane Cost Adjustment Rate 99
Original Sheet Nos. 41.1-41.2	Purchased Propane Cost Adjustment Rate 99
Original Sheet Nos. 42-42.2	General Revisions Rate 100
1st Revised Sheet No. 42.3	General Revisions Rate 100
Original Sheet Nos. 42.4-42.16	General Revisions Rate 100
Original Sheet No. 44	Rate for Residential Gas Service for Regular Employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc. and Wholly-Owned Subsidiaries of MDU Resources Group, Inc. Rate 102
Original Sheet Nos. 61-61.1	Interruptible Gas Service Extension Policy Rate 119
1st Revised Sheet No. 62	Firm Gas Service Extension Policy Rate 120
Sub.1st Rev. Sheet Nos. 62.1-62.4	Firm Gas Service Extension Policy Rate 120
Original Sheet No. 62.5	Firm Gas Service Extension Policy Rate 120
Original Sheet Nos. 66-66.1	New Installation, Replacement, Relocation and Repair of Gas Service Lines Rate 124

V.

That Applicant respectfully submits herewith the following described proposed rate schedules for gas service, copies attached hereto as Appendix B, which Applicant proposes to substitute for the rate schedules described in the preceding paragraph.

Volume No. 7

Original Sheet No. 1	Table of Contents
Original Sheet No. 2	Communities Served
Original Sheet No. 3	Rate Summary
Original Sheet No. 4	Residential Gas Service Rate 60
Original Sheet Nos. 5-6	Reserved
Original Sheet No. 7	Air Force Rate 64
Original Sheet No. 8-12	Reserved
Original Sheet No. 13	Firm General Gas Service Rate 70
Original Sheet No. 14	Small Interruptible General Gas Service Rate 71
Original Sheet No. 15	Optional Seasonal General Gas Service Rate 72
Original Sheet No. 16-23	Reserved
Original Sheet No. 24	Transportation Service Rates 81 and 82
Original Sheet No. 25-26	Reserved
Original Sheet No. 27	Large Interruptible General Gas Service Rate 85
Original Sheet No. 28-29	Reserved
Original Sheet No. 30	Purchased Gas Cost Adjustment Rate 88
Original Sheet No. 31	Reserved
Original Sheet No. 32	Residential Propane Service Rate 90
Original Sheet No. 33	Reserved
Original Sheet No. 34	Firm General Propane Service Rate 92
Original Sheet No. 35-40	Reserved
Original Sheet No. 41	Purchased Propane Cost Adjustment Rate 99
Original Sheet No. 42	General Provisions Rate 100
Original Sheet No. 43	Reserved
Original Sheet No. 44	Residential Rate for Regular Employees Rate 102
Original Sheet No. 45-60	Reserved
Original Sheet No. 61	Interruptible Gas Service Extension Policy Rate 119

Original Sheet No. 62	Firm Gas Service Extension Policy Rate 120
Original Sheet No. 63-65	Reserved
Original Sheet No. 66	New Installation, Replacement, Relocation and Repair of Gas Service Lines Rate 124

VI.

That the existing rates of Applicant are unjust, unreasonable and not compensatory, and that said rates should be increased so that Applicant will have an opportunity to earn a just and reasonable rate of return on its natural gas property devoted to providing service to its North Dakota natural gas customers.

VII.

That in submitting this Application and in proposing the implementation of the increased rates contained herein, Applicant is seeking additional revenues before income taxes of $2,844,132 based on a 2003 future test year, for natural gas service rendered to customers in the State of North Dakota.

VIII.

That Applicant will prove by competent evidence that existing rates are unjust, unreasonable, and not compensatory, and that said rate schedules should be increased as requested herein. Filed concurrently with this Application and its Appendices are supporting Statements and direct testimony and exhibits of Applicant's witnesses. Said Statements, Testimony and Exhibits are by this reference incorporated as if fully set forth herein.

IX.

That this Application is submitted in accordance with the provisions of Title 49 of the North Dakota Century Code and the rules and regulations promulgated by the Public Service Commission of the State of North Dakota.

X.

That, in accordance with Section 49-05-04.1 of the North Dakota Century Code, Applicant hereby affirms that its future test year forecast is reasonable, reliable, and made in good faith. All basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the Commission to test the appropriateness of the forecast. The accounting treatment that has been applied to anticipated events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred.

WHEREFORE, Applicant respectfully requests that the Public Service Commission of the State of North Dakota:

1. Approve and adopt the proposed rate changes as set forth in Appendix B of this Application to be effective upon final disposition of this case;

2. Expedite any hearing which the Commission deems necessary to determine the propriety of Applicant's proposed rate schedules set forth herein, and issue its final order establishing the rates set forth herein; and

3. Grant such other and additional relief as the Commission shall deem just and proper.

Dated this 12th day of April, 2002.

MONTANA-DAKOTA UTILITIES CO.,
a Division of MDU Resources Group, Inc.

By: Donald R. Ball
Donald R. Ball
Director of Regulatory Affairs

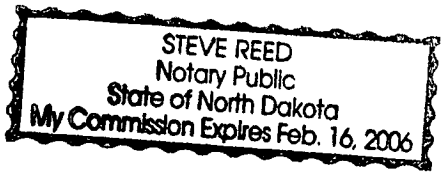
STATE OF NORTH DAKOTA)
:ss
COUNTY OF BURLEIGH)

Donald R. Ball, being first duly sworn, deposes and says that he is the Director of Regulatory Affairs of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., the Applicant herein, that he has read the foregoing Application, knows the contents thereof, and that the same is true and correct to the best of his knowledge, information and belief.

Dated this 12th day of April, 2002.

Donald R. Ball
Director of Regulatory Affairs

Subscribed and sworn to before me this 12th day of April, 2002.



Steve Reed, Notary Public
Burleigh County, North Dakota
My Commission Expires:
02/16/06

OF COUNSEL:

Douglas W. Schulz
Senior Attorney
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

William P. Pearce
Pearce & Durick
314 E. Thayer Avenue
Bismarck, ND 58501

CERTIFICATE

STATE OF NORTH DAKOTA)
: ss
COUNTY OF BURLEIGH)

I, Craig A. Keller, Vice President, Controller and Chief Accounting Officer of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., do hereby certify that the cost statements, working papers, and other supporting data submitted by Montana-Dakota Utilities Co. as a part of its application for Authority to Establish Increased Rates for Natural Gas Service with the North Dakota Public Service Commission, or which are maintained by the Company in support of such filed Application and which purport to reflect the books of the Company, do in fact set forth the results shown by such books.

Dated this 12th day of April, 2002.

Craig A. Keller
Vice President, Controller &
Chief Accounting Officer

Subscribed and sworn to before me this 12th day of April, 2002.

STEVE REED
Notary Public
State of North Dakota
My Commission Expires Feb. 16, 2006

Steve Reed, Notary Public
Burleigh County, North Dakota
My Commission Expires: 02/16/06

MONTANA-DAKOTA UTILITIES CO
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 5
2nd Revised Sheet No. 1
Canceling 1st Revised Sheet No. 1

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72	Optional Seasonal General Gas Service	15
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Date Filed: November 4, 1999 Effective Date: Bills rendered on or after December 15, 1999

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-99-601

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS AND PROPANE SERVICE
RATE SCHEDULE

NDPSC Volume 6
1st Revised Sheet No. 2
Cancelling Original Sheet No. 2

COMMUNITIES SERVED
*Designates Division Office

NATURAL GAS SERVICE

R A T E Z O N E 1
(Customer-Owned Service Lines)

Bismarck Division

Apple Valley	Glen Ullin	Mandan	Wilton
Bismarck*	Lincoln	New Salem	

Dickinson Division

Beach	Gladstone	Marmarth	Richardton
Belfield	Golva	Mott	Sentinel Butte
Bowman	Hebron	New England	South Heart
Dickinson*	Killdeer	Regent	Taylor
East Fairview	Lefor	Rhame	

Minot Division

Berthold	Garrison	Riverdale	Underwood
Burlington	Max	Surrey	Washburn
Des Lacs	Minot*	Turtle Lake	

Williston Division

Alexander	Ray	Tioga	White Earth
Arnegard	Ross	Trenton	Williston*
Epping	Springbrook	Watford City	
Palermo	Stanley	Wheelock	

R A T E Z O N E 2
(Company-Owned Service Lines)

Bismarck Division

Barlow	Eldridge	Sandborn	Valley City
Carrington	Jamestown	Sheyenne	Linton
Cleveland	Medina	Steele	
Dawson	New Rockford	Tappen	

Minot Division

Cavalier	Fort Totten	Langdon	Walhalla
Devils Lake	Grafton	Park River	

Williston Division
Lignite

PROPANE SERVICE

Dickinson Division
Hettinger

Date Filed: November 11, 1998 Effective Date: December 2, 1998

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-98-548

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKO
GAS RATE SCHEDULE

NDPSC Volume 6
2nd Revised Sheet No. 3
Cancelling 1st Revised Sheet No. 3

RESIDENTIAL GAS SERVICE Rate 60

AVAILABILITY:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.

RATE:

Base Rate Per Month:

Zones 1 and 2

For customers with meters rated under 500 cubic feet per hour $ 6.50
For customers with meters rated over 500 cubic feet per hour $13.00

Commodity Charge:

Zone 1	
First 5 dk per month	$4.681 per dk
Over 5 dk per month	$4.230 per dk
Zone 2	
First 5 dk per month	$4.851 per dk
Next 10 dk per month	$4.400 per dk
Over 15 dk per month	$4.230 per dk

MINIMUM BILL:

Base Rate.

PAYMENT:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

RULES - The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: December 18, 1998 Effective Date: With service rendered on and after January 15, 1999

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-96-325

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKO GAS RATE SCHEDULE

NDPSC Volume 6
2nd Revised Sheet No. 5
Cancelling 1st Revised Sheet No. 5

OPTIONAL SEASONAL RESIDENTIAL GAS SERVICE Rate 62

AVAILABILITY:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.

RATE:

Base Rate Per Month:

Zones 1 and 2

For customers with meters rated under 500 cubic feet per hour $ 6.50

For customers with meters rated over 500 cubic feet per hour $13.00

Commodity Charge:

Zone 1	Winter	Summer
First 5 dk per month	$4.795 per dk	$3.687 per dk
Over 5 dk per month	$4.344 per dk	$3.236 per dk

Zone 2	Winter	Summer
First 5 dk per month	$4.965 per dk	$3.857 per dk
Next 10 dk per month	$4.514 per dk	$3.406 per dk
Over 15 dk per month	$4.344 per dk	$3.236 per dk

Winter - Effective for bills rendered October 1 through May 31

Summer - Effective for bills rendered June 1 through September 30

MINIMUM BILL:

Base Rate.

PAYMENT:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

Date Filed: December 18, 1998 Effective Date: With service rendered on and after January 15, 1999

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-96-325

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
Original Sheet No. 5.1
Cancelling Vol 5, Orig Sheet No. 5.1

OPTIONAL SEASONAL RESIDENTIAL GAS SERVICE Rate 62

GENERAL TERMS AND CONDITIONS:

1. TERM - The customer agrees to contract for service under the Optional Seasonal Residential Gas Service Rate 62 for a minimum of one year.

2. RULES - The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: November 10, 1994
Effective Date: Service Rendered on and After November 15, 1994

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-94-297

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group Inc
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
Original Sheet No. 7
Cancelling Vol 5, 2nd Rev Sheet No. 7

AIR FORCE Rate 64

AVAILABILITY:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

RATE:

Base Rate Per Meter:

Minot Air Force Base - $750.00 per month
Perimeter Acquisition Radar (PAR) Site - $35.00 per month

Minot Air Force Base:

Firm Sales	
Commodity Charge	$1.932 per dk
Plus Applicable Pipeline Demand & Transportation Charges	
Interruptible Sales	
Commodity Charge	$1.885 per dk
Plus Applicable Pipeline Transportation Charges	

PAR Site & Minot Air Force Base Pro Shop:

Firm Sales	
Commodity Charge	$3.840 per dk
Interruptible Sales	
Commodity Charge	$2.672 per dk
Interruptible Transportation	
Transportation Charge	$ .124 per dk
Balancing Charge	$ .342 per dk
Fuel Charge	See Supplemental Sheet

The terms and conditions of service applicable under Transportation Service Rates 81, 82, 84 shall also apply to services rendered under Air Force Rate 64.

MINIMUM BILL:

Base Rate.

Date Filed: November 10, 1994 Effective Date: Service Rendered on and After November 15, 1994

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-94-297

AIR FORCE Rate 64

PAYMENT:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

1. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the firm sales commodity charge rate set forth above, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $10.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

2. CONTRACT - Terms of service other than the rate shall be as specified in contracts between Minot Air Force Base, and PAR and the Company.

3. RULES - The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
2nd Revised Sheet No. 13
Cancelling 1st Revised Sheet No. 13

FIRM GENERAL GAS SERVICE Rate 70

AVAILABILITY:

In all communities served for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

RATE:

Base Rate Per Month:

Zones 1 and 2

For customers with meters rated under 500 cubic feet per hour	$ 8.50
For customers with meters rated over 500 cubic feet per hour	$17.00

Commodity Charge:

Zone 1

First 15 dk per month	$4.748 per dk
Over 15 dk per month	$4.248 per dk

Zone 2

First 15 dk per month	$4.918 per dk
Over 15 dk per month	$4.248 per dk

MINIMUM BILL:

Base Rate.

PAYMENT:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

RULES - The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: December 18, 1998 Effective Date: With service rendered on and after January 15, 1999

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-96-325

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKO...
GAS RATE SCHEDULE

NDPSC Volume 6
1st Revised Sheet No. 14
Cancelling Original Sheet No. 14

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

AVAILABILITY:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

RATE:

Base Rate (Zones 1 and 2): $35.00 per month

Commodity Charge:	Maximum Rate	Minimum Rate
Zone 1	$3.500 per dk	$3.056 per dk
Zone 2		
First 15 dk per month	$3.670 per dk	$3.670 per dk
Over 15 dk per month	$3.500 per dk	$3.056 per dk

The commodity charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the cost of Purchased Gas Adjustment, shall apply for the term of the agreement regardless of a change in the rates set forth above.

MINIMUM BILL:

Base Rate.

PAYMENT:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

Date Filed: November 11, 1998 Effective Date: December 2, 1998

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-98-548

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

GENERAL TERMS AND CONDITIONS:

1. PRIORITY OF SERVICE - Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the tail block of the applicable General Gas Service Rate 70 commodity charge rate, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $10.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT - Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

GENERAL TERMS AND CONDITIONS: (Cont.)

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS - Electronic measurement equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder.

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and a telephone tie to customer's telephone system accessible at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

6. RULES - The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
2nd Revised Sheet No. 15
Cancelling 1st Revised Sheet No. 15

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

AVAILABILITY:

In all communities served for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

RATE:

Base Rate Per Month:

Zones 1 and 2

For customers with meters rated under 500 cubic feet per hour	$ 8.50
For customers with meters rated over 500 cubic feet per hour	$17.00

Commodity Charge:

Zone 1	Winter	Summer
First 15 dk per month	$4.861 per dk	$3.753 per dk
Over 15 dk per month	$4.361 per dk	$3.253 per dk

Zone 2	Winter	Summer
First 15 dk per month	$5.031 per dk	$3.923 per dk
Over 15 dk per month	$4.361 per dk	$3.253 per dk

Winter - Effective for bills rendered October 1 through May 31
Summer - Effective for bills rendered June 1 through September 30

MINIMUM BILL:

Base Rate.

PAYMENT:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

Date Filed: December 18, 1998 Effective Date: With service rendered on and after January 15, 1999

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-96-325

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
Original Sheet No. 15.1
Cancelling Vol 5, Orig Sheet No. 15.1

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

GENERAL TERMS AND CONDITIONS:

1. TERM - The customer agrees to contract for service under the Optional Seasonal General Gas Service Rate 72 for a minimum of one year.

2. RULES - The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: November 10, 1994
Effective Date: Service Rendered on and After November 15, 1994

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-94-297

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

AVAILABILITY:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through Company's distribution facilities. In order to obtain transportation service, customer must qualify under an applicable gas transportation service rate; meet the general terms and conditions of service provided hereunder; and enter into a gas transportation agreement upon request by the Company.

The transportation services are as follows:

Small Interruptible General Gas Transportation Service Rate 81:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point, whose average use of natural gas will not exceed 100,000 dk annually, and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Small Interruptible General Gas Service Rate 71. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70 or Firm Gas Transportation Service Rate 84, whichever is applicable.

Large Interruptible General Gas Transportation Service Rate 82:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point, whose average use of natural gas will exceed 100,000 dk annually, and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Large Interruptible General Gas Service Rate 85. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70 or Firm Gas Transportation Service Rate 84, whichever is applicable.

Firm Gas Transportation Service Rate 84:
Firm transportation service is available for the firm requirements of those customers who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

AVAILABILITY: (Cont.)

Firm Gas Transportation Service Rate 84: (Cont.)

Company's effective Small Interruptible General Gas Service Rate 71 or Large Interruptible General Gas Service Rate 85. Such firm requirements, subject to approval by the Company, must be set forth in a firm service agreement.

RATE:

Under Rate 81 or Rate 82, customer shall pay the applicable Base Rate and Nomination Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71, Rate 84 or Rate 85, the base rate applicable under Rate 81 or Rate 82 shall be waived.

Base Rate:

Rate 81 - $ 35.00 per month
Rate 82 - $450.00 per month
Rate 84 - $ 35.00 per month for customers qualifying under Rate 81
$450.00 per month for customers qualifying under Rate 82

	Rate 81	Rate 82	Rate 84
Maximum Rate per dk	$0.509	$0.321	$0.983
Minimum Rate per dk	$0.102	$0.061	$0.983
Balancing Charge per dk	$0.342	$0.342	$0.342
Nomination Charge per Month	$50.00	$50.00	$50.00

Fuel Charge:

Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See supplemental sheet for currently effective charge.

GENERAL TERMS AND CONDITIONS:

1. CRITERIA FOR SERVICE - In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

2. REQUEST FOR GAS TRANSPORTATION SERVICE:
   a. To qualify for gas transportation service a customer must request the service pursuant to the provisions set forth herein. The service shall be provided only to the extent that the Company's existing operating capacity permits.

   b. If the Company determines that firm capacity exists, requests for firm gas transportation service shall be processed on a first come first serve basis. Requests for interruptible transportation service shall be considered in accordance with the provisions of Rate 100, §V.10.

3. MULTIPLE SERVICES THROUGH ONE METER:
   a. In the event customer desires firm sales service in addition to gas transportation service, customer shall request such firm volume requirements, and upon approval by Company, such firm volume requirements shall be set forth in a firm service agreement. For billing purposes, the level of volumes so specified or the actual volume used, whichever is lower, shall be billed at Rate 70 or Rate 84, whichever is applicable. Volumes delivered in excess of such firm volumes shall be billed at the applicable gas transportation rate. Customer has the option to install, at their expense, piping necessary for separate measurement of sales and transportation volumes.

   b. The customer shall pay, in addition to charges specified in the applicable gas transportation rate schedule, charges under all other applicable rate schedules for any service in addition to that provided herein (irrespective of whether the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE - Company shall have the right to curtail or interrupt deliveries without being required to give previous notice of intention to curtail or interrupt, whenever, in its judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

5. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken above that received on customer's behalf, shall be billed at the tail block of the applicable Firm General Gas Service Rate 70 commodity charge rate, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $10.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

6. NON-DELIVERED VOLUMES/PENALTY:

a. In the event customer uses more gas than is being delivered to the Company's interconnection with the delivering pipeline(s) (receipt point), customer shall pay an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper at the same receipt point, any payment or overrun penalties the Company is required to make shall be allocated on a pro rata basis among such customers on the basis of each customer's use of gas in excess of available volumes.

b. In the event the customer's gas is not being delivered to the receipt point due to shipper or pipeline constraints and the customer continues to take gas, the rate charged to the customer shall be the tail block of the Firm General Gas Service Rate 70 commodity charge rate, plus any applicable penalties or charges set forth in Paragraph 6.a. The Company is under no obligation to notify customer of non-delivered volumes.

c. In the event customer's transportation volumes are not available for any reason, customer may take interruptible sales service if such service is available. The availability of interruptible sales service shall be determined at the sole discretion of the Company.

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

7. ELECTION OF SERVICE - Prior to the initiation of service hereunder, the customer shall make an election of its requirements under each applicable rate schedule for the entire term of service. If mutually agreed to by Company and customer, the term of service may be amended. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under the appropriate sales rate schedule for the customer's operations.

   Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge as specified in Rate 100, §V.17.

8. BALANCING:

   a. To the extent practicable, customer and Company agree to the daily balancing of volumes of gas received and delivered on a thermal basis. Such balancing is subject to the customer's request and the Company's discretion to vary scheduled receipts and deliveries within existing Company operating limitations.

      If, at the end of a billing month, the accumulated difference between actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer exceeds 4% of that month's scheduled receipts, resulting in a negative imbalance (i.e., deliveries exceed scheduled receipts), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, the customer shall then be billed, in addition to the applicable transportation rate, a penalty for the under nominated volume exceeding 4% at the tail block of the Firm General Gas Service Rate 70 commodity charge rate. The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume on which a penalty was imposed.

      If, at the end of a billing month, the accumulated difference between nominated (scheduled) receipts on behalf of such customer and actual gas deliveries to the customer exceeds 4% of that month's scheduled receipts resulting in a positive imbalance (i.e., scheduled receipts exceed deliveries), the customer will be assessed a balancing charge, set forth herein,

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

8. BALANCING: (Cont.)

a. on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, (1) the Company may adjust the volume of gas received on behalf of the customer so as to eliminate the prior period over nomination exceeding 4% up to 10% and (2) the Company shall retain the over nomination of gas exceeding 10% free and clear of any adverse claims relating thereto when such accumulated difference exceeds 50 dk. The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume retained.

b. In the event customer's imbalance causes the Company to incur a balancing penalty from its interconnecting pipeline(s), customer shall pay any penalty payments or overrun charges the Company is required to make under the terms of its contract(s) with interconnecting pipeline(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper at the same interconnection with a delivering pipeline, any payment or overrun penalties the Company is required to make shall be apportioned among such customers on the basis of each customer's contribution toward the imbalance.

c. Customer's nominations made to clear imbalances will be subject to the priority of service and allocation of capacity provisions set forth in Rate 100, §V.10 and the penalties for failure to curtail or interrupt use of gas set forth in Paragraph 5 of this rate schedule.

d. Termination of the gas transportation service shall not relieve Company and customer of the obligation to correct any quantity imbalances hereunder or customer of the obligation to pay money due hereunder to Company.

e. The Company may waive any penalty associated with Company adjustments to end-use customer nominations in those instances where the Company, due to operating limitations, is required to adjust end-use transportation customer nominations and such Company adjustments create a penalty situation, or preclude a customer from correcting an imbalance which results in a penalty.

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

9. NOMINATION VARIANCE CHARGE - The customer shall pay any payments the Company must make to its interconnecting pipeline(s), as a result of nomination variance penalties caused by customer's nomination variances. Such penalties will be allocated on the basis of each customer's contribution toward the nomination variance.

10. METERING REQUIREMENTS:

a. Electronic measurement equipment required by the Company for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by the customer. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. Company may remove such equipment when service hereunder is terminated.

b. The customer shall provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and a telephone tie to customer's telephone system accessible at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

11. DAILY NOMINATION REQUIREMENTS:

a. Customer or customer's agent shall advise Company's gas nominations center, by 11:30 a.m. Central Clock Time, of the dk requirements customer has requested to be delivered at each delivery point the following day. Customer's daily nomination shall be its best estimate of the expected utilization for the gas day. Unless other arrangements are made, customer will be required to nominate for the non-business days involved prior to weekends and holidays.

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

11. DAILY NOMINATION REQUIREMENTS: (Cont.)

b. All nominations should include shipper defined begin and end dates. Shippers may nominate for periods longer than 1 day, provided the nomination begin and end dates are within the term of the service agreement.

c. The Company has the sole right to refuse receipt of any volumes which exceed the maximum daily contract quantity and at no time shall the Company be required to accept quantities of gas for a customer in excess of the quantities of gas to be delivered to customer. If total nominated receipts exceed total deliveries at receipt points where more than one customer is receiving service, nominations will be allocated on a pro rata basis.

d. At no time shall Company have the responsibility to deliver gas in excess of customer's nomination.

e. In the event that more than one customer is receiving gas from the same shipper at the same receipt point, any reduction in nominated volumes will be allocated on a pro rata basis, unless Company and shipper(s) have agreed to a predetermined allocation procedure.

12. WARRANTY - The customer, customer's agent, or customer's shipper warrants that it will have title to all gas it tenders or causes to be tendered to the Company, and such gas shall be free and clear of all liens and adverse claims and the customer, customer's agent, or customer's shipper shall indemnify the Company against all damages, costs, and expenses of any nature whatsoever arising from every claim against said gas.

13. FACILITY EXTENSIONS - If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities required to furnish firm gas service, the customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. Company may remove such facilities when service hereunder is terminated.

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

14. PAYMENT - Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

15. BILLING ERROR - In the event an error is discovered in any bill that the Company renders to customer, such error shall be adjusted within a period not to exceed 6 months from the date the billing error is first discovered.

16. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for service hereunder.

17. RULES - The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
1st Revised Sheet No. 27
Cancelling Original Sheet No. 27

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

AVAILABILITY:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

This rate schedule shall not apply for service to U.S. Government installations which are covered by separate special contracts.

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

RATE: (Zones 1 and 2)

Base Rate: $450.00 per month

Commodity Charge:

Maximum Rate	$3.290 per dk
Minimum Rate	$2.869 per dk

The commodity charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the cost of Purchased Gas Adjustment, shall apply for the term of the agreement regardless of a change in the rates set forth above.

MINIMUM BILL:

Base Rate.

PAYMENT:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

Date Filed: November 11, 1998 Effective Date: December 2, 1998

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-98-548

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

GENERAL TERMS AND CONDITIONS:

1. PRIORITY OF SERVICE - Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the tail block of the applicable General Gas Service Rate 70 commodity charge rate, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $10.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT - Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 90 days prior to the end of the initial term. Absent execution of such termination notice, the agreement shall continue for additional terms of equal length until written notice is given as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

GENERAL TERMS AND CONDITIONS: (Cont.)

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS - Electronic measurement equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder.

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and a telephone tie to customer's telephone system accessible at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

6. RULES - The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
4th Revised Sheet No. 30
Cancelling 3rd Revised Sheet No. 30

PURCHASED GAS COST ADJUSTMENT Rate 88

1. APPLICABILITY:
This rate schedule constitutes a purchased gas cost adjustment (PGA) provision and specifies the procedure to be utilized to adjust the rates for gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of gas supply, (b) amortization of the Unrecovered Purchased Gas Cost Account and (c) market based pricing differential.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:
(a) The effective dates of the PGA shall be bills rendered on and after the first day of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file an adjustment to reflect changes in its average cost of gas supply only when the amount of such adjustment is at least 10 (ten) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. PURCHASED GAS COST ADJUSTMENT:
(a) The monthly PGA shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent general rate case. The cost of gas supply shall be the sum of all costs incurred in obtaining gas for general system supply. General system supply is defined as gas available for use by all customers served under retail sales rate schedules. The cost of gas supply shall include, but not be limited to, all demand, commodity, storage, gathering, and transportation charges incurred by Montana-Dakota for such gas supply, the overall rate of return on prepaid demand and commodity charges and gas storage balances required to maintain the system gas supply and hedging program gains, losses and transaction costs related to system gas supply. Authority for inclusion of hedging program gains, losses and transaction costs expires on March 1, 1999 unless otherwise ordered by the Commission. Montana-Dakota shall submit, with each filing under this tariff, a complete report of hedging program activity.

Date Filed: December 11, 1998 Effective Date: January 27, 1999

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-98-53

PURCHASED GAS COST ADJUSTMENT Rate 88

3. PURCHASED GAS COST ADJUSTMENT: (Cont.)

(b) The PGA shall be computed as follows:

(1) Demand costs shall include all annual gathering, transportation and storage demand charges at current rates.

(2) Commodity costs shall include all annual gathering, transportation and storage charges at current rates.

(3) The gas commodity cost shall reflect all commodity related gas costs estimated to be in effect for the month the PGA will be in effect and annual dk requirements.

(4) The return on prepaid demand and commodity balances and storage balances shall be computed on an annual basis at the overall rate of return on rate base.

The cost per dk for the month is the sum of the above divided by annual, weather normalized dk deliveries adjusted to reflect losses.

(c) Monthly gas costs shall be calculated as follows:

(1) Demand costs for firm customers shall be apportioned to all state jurisdictions served by Montana-Dakota on the basis of the overall ratio of each state's Maximum Daily Delivery Quantity (MDDQ).

(2) Demand costs for interruptible sales customers shall be stated on a 100% load factor basis.

(3) All commodity costs and other costs associated with the acquisition of gas for general system supply shall be apportioned to each state on the basis of total dks sold in each state, regardless of the actual points of delivery of such gas.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
APR - 2 1997
CASE NO. PU-399-97-76

Date Filed: February 25, 1997 Effective Date:

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.:

PURCHASED GAS COST ADJUSTMENT Rate 88

3. PURCHASED GAS COST ADJUSTMENT: (Cont.)

(c) (4) The return requirement related to prepaid demand and commodity charges and gas storage balances shall be included on a per dk basis. The prepaid demand and storage balances shall be apportioned to all states on the basis of each state's MDDQ. The prepaid commodity charges shall be apportioned to all states on the basis of annual dks sold in each state. The unit cost shall be calculated using a thirteen month average balance and the currently authorized return on rate base.

(5) All costs related to specific end-use transactions shall not be included in the cost of gas supply determination but shall be directly billed to the customer(s) contracting for such service.

(d) The PGA shall be applied to each of Montana-Dakota's rate schedules recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. SURCHARGE ADJUSTMENT:

(a) All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on May 1 of each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Gas Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

5. UNRECOVERED PURCHASED GAS COST ACCOUNT:

(a) Items to be included in the Unrecovered Purchased Gas Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in a Purchased Gas Cost Adjustment by reason of the one-tenth of one cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for gas supplies which were paid during any period after the effective date of the most recent general rate case, but not yet included in sales rates.

PURCHASED GAS COST ADJUSTMENT Rate 88

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

(a) (3) Refunds received from supplier(s) with respect to gas supply. Such refunds received shall be credited to the Unrecovered Purchased Gas Cost Account.

(4) Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

(5) Demand costs recovered from the interruptible sales customers will be credited to the residential and firm general service customers.

(b) (1) The amount to be included in the Unrecovered Purchased Gas Cost Account in order to reflect the items specified in Subsections 5(a)(1), (2), and (3) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's natural gas supply as adjusted to levelize demand charges.

Such adjustment to levelize supplier(s) demand charges shall be calculated as follows:

The suppliers' annual (calendar or fiscal) demand charges, which are payable in equal monthly payments, shall be accumulated in a prepaid account (FERC Account 165). Each month a portion of such accumulated prepaid amount shall be amortized to cost of natural gas purchased (FERC Account 804). Such monthly amortization shall be based on a rate calculated by dividing the annual supplier(s) demand charges by projected annual natural gas sales units (calendar or fiscal, as appropriate). The resulting product shall then be multiplied by the projected natural gas unit sales for the current month. Such amount shall constitute the monthly amortization of prepaid supplier(s) demand charges to cost of natural gas supply.

PURCHASED GAS COST ADJUSTMENT Rate 88

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

(b) (1) (ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for gas supply which is reflected in the currently effective PGA (the cost of gas supply approved in the most recent rate case plus the Purchased Gas Cost Adjustment as calculated in Subsection 3(a)).

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Gas Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Gas Cost Account, Account 191, at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The amount to be included in Account 191 for carrying charges shall be determined as follows:

Each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Unrecovered Purchased Gas Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

PURCHASED GAS COST ADJUSTMENT Rate 88

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

(c) Reduction of Amounts in the Unrecovered Purchased Gas Cost Account:

(1) The amounts in the Unrecovered Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Gas Cost Account specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Unrecovered Purchased Gas Cost Account specified in Subsection 5(a)(4).

6. MARKET-BASED PRICING DIFFERENTIAL:

(a) At the time of each surcharge adjustment, the Company will compute a credit to residential and firm general service rates based on 50% of all non-gas commodity revenues received from small interruptible sales and large interruptible sales customers in excess of the authorized non-gas commodity rate approved in the most recent general rate case.

(b) The unit adjustment shall be determined by dividing the balance resulting under Subsection 6(a) by the residential and firm general service sales volumes estimated to be sold during the 12 months following the effective date of each adjustment.

7. TIME AND MANNER OF FILING:

(a) Montana-Dakota shall file each adjustment at least 20 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised PGA sheets identifying the amounts of the adjustments and the resulting currently effective PGA rates.

(b) Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant pipeline tariff sheets supporting costs claimed.

RESIDENTIAL PROPANE SERVICE Rate 90

AVAILABILITY:
For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

RATE:
Base Rate Per Month:

For customers with meters rated under 500 cubic feet per hour	$ 6.50
For customers with meters rated over 500 cubic feet per hour	$13.00

Commodity Charge:

First 5 dk per month	$5.569
Next 10 dk per month	$5.118
Over 15 dk per month	$4.948

MINIMUM BILL:
Base Rate.

PAYMENT:
Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

PURCHASED PROPANE COST ADJUSTMENT:
Bills are subject to an adjustment for cost of purchased propane as provided in Rate 99 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:
1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from the date of disconnection and shall be subject to reconnection charges to restore service after the one year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state

FIRM GENERAL PROPANE SERVICE Rate 92

AVAILABILITY:
For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

RATE:
Base Rate Per Month:

For customers with meters rated under 500 cubic feet per hour	$ 8.50
For customers with meters rated over 500 cubic feet per hour	$17.00

Commodity Charge:

First 15 dk per month	$5.636
Over 15 dk per month	$4.966

MINIMUM BILL:
Base Rate.

PAYMENT:
Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

PURCHASED PROPANE COST ADJUSTMENT:
Bills are subject to an adjustment for cost of purchased propane as provided in Rate 99 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from the date of disconnection and shall be subject to reconnection charges to restore service after the one year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKO GAS RATE SCHEDULE

NDPSC Volume 6
50th Revised Sheet No. 41
Canceling 49th Revised Sheet No. 41

PURCHASED PROPANE COST ADJUSTMENT Rate 99

1. AVAILABILITY:

This rate schedule constitutes a purchased propane cost adjustment (PCA) provision and specifies the procedure to be utilized to adjust the rates for propane gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of propane supply and (b) amortization of the Unrecovered Purchased Propane Cost Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

(a) The effective dates of the PCA shall be bills rendered on and after the first day of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file an adjustment to reflect changes in its average cost of propane supply only when the amount of such adjustment is at least 10 (ten) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. PURCHASED PROPANE COST ADJUSTMENT:

(a) The monthly PCA shall reflect changes in Montana-Dakota's cost of propane supply as compared to the cost of propane supply approved in its most recent retail sales rates. The cost of propane supply shall include, but not be limited to, all commodity and transportation charges incurred by Montana-Dakota for such propane supply.

(b) The propane commodity cost shall reflect all commodity related propane costs estimated to be incurred for the month the PCA will be in effect and estimated dk purchases.

The unit cost per dk for the month shall be the commodity costs divided by estimated dk purchases for the month.

4. SURCHARGE ADJUSTMENT:

All propane sales schedules shall be subject to a Surcharge Adjustment to be effective on May 1 of each year. The Surcharge Adjustment per dk sold shall reflect amorization of the applicable balance in the Unrecovered Purchased Propane Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

Date Filed: November 4, 1999 Effective Date: Bills rendered on or after December 15, 1999

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-99-601

PURCHASED PROPANE COST ADJUSTMENT Rate 99

5. UNRECOVERED PURCHASED PROPANE COST ACCOUNT:

(a) Items to be included in the Unrecovered Purchased Propane Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for propane supply which Montana-Dakota is unable to reflect in a Purchased Propane Cost Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for propane supplies that were paid during any period after the effective date of the most recent approved rates, but not yet included in propane sales rates.

(3) Carrying charges or credits.

(b) (1) The amount to be included in the Unrecovered Purchased Propane Cost Account in order to reflect the items specified in Subsections 5(a)(1) and (2) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's propane supply.

(ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for propane supply which is reflected in the currently effective PCA.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each propane rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Propane Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Propane Cost Account, Account 191, as follows:

Each month, Account 191 shall be debited (on a debit balance) or credited (on a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

PURCHASED PROPANE COST ADJUSTMENT Rate 99

(i) The balance on Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The carrying charges shall be accrued in a supplementary Unrecovered Purchased Propane Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

c) Reduction of Amounts in the Unrecovered Purchased Propane Cost Account:

(1) The amounts in the Unrecovered Purchased Propane Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Propane Cost Account specified in Subsections 5(a)(1) and (2) and the amounts in the supplementary Unrecovered Purchased Propane Cost Account specified in Subsection 5(b)(2)(ii).

6. TIME AND MANNER OF FILING:

(a) Montana-Dakota shall file each adjustment at least 10 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised PCA sheets identifying the amounts of the adjustments and the resulting currently effective PCA rates.

(b) Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant material supporting costs claimed.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
Original Sheet No. 42
Cancelling Vol 5, 2nd Rev Sheet No. 42

GENERAL PROVISIONS Rate 100

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Date Filed: November 10, 1994 Effective Date: Service Rendered on and After November 15, 1994

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-94-297

GENERAL PROVISIONS Rate 100

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GENERAL PROVISIONS Rate 100

I. PURPOSE:

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Service Commission of North Dakota and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

APPLICANT - A customer requesting Company to provide service.

COMMISSION - Public Service Commission of the State of North Dakota.

COMPANY - Montana-Dakota Utilities Co.

COMPANY'S OPERATING CONVENIENCE - The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT - A reduction of transportation or retail natural gas service deemed necessary by the Company. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

CUSTOMER - Any individual, partnership, corporation, firm, other organization or government agency supplied with service by Company at one location and at one point of delivery unless otherwise expressly provided in these rules or in a rate schedule.

GENERAL PROVISIONS Rate 100

II. DEFINITIONS: (Cont.)

DELIVERY POINT - The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on customer's premises.

GAS DAY - Means a period of twenty-four consecutive hours, beginning and ending at 9:00 a.m. Central Clock Time.

INTERRUPTION - A cessation of transportation or retail natural gas service deemed necessary by Company.

NOMINATION - The daily dk volume of natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

PIPELINE - The transmission company(s) delivering natural gas into company's system.

RATE - Shall mean and include every compensation, charge, fare, toll, rental and classification, or any of them, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT - The intertie between Company and the interconnecting pipeline(s) at which point Company assumes custody of the gas being transported.

SHIPPER - The party with whom the Pipeline has entered into a service agreement for transportation services.

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE - A customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. The Company may refuse a customer or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service

GENERAL PROVISIONS Rate 100

III. CUSTOMER OBLIGATIONS: (Cont.)

1. APPLICATION FOR SERVICE - (Cont.)
account. Any customer who uses gas service in the absence of application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

Any customer may be required to make a deposit as required.

2. INPUT RATING - All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at Company's sole discretion, Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will ensure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

3. ACCESS TO CUSTOMER'S PREMISES - Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

4. COMPANY PROPERTY - The customers shall exercise reasonable diligence in protecting the Company's property on their premises, and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

GENERAL PROVISIONS Rate 100

III. CUSTOMER OBLIGATIONS: (Cont.)

5. INTERFERENCE WITH COMPANY PROPERTY - The customer shall not disconnect, change connections, make connections or otherwise interfere with Company's meters or other property or permit same to be done by other than the Company's authorized employees.

6. NOTIFICATION OF LEAKS - The customer shall immediately notify the Company at its office of any escape of gas in or about the customer's premises.

7. TERMINATION OF SERVICE - All customers are required to notify the Company, to prevent their liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

8. REPORTING REQUIREMENTS - Customer shall furnish Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

IV. LIABILITY:

1. CONTINUITY OF SERVICE - The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

2. CUSTOMER'S EQUIPMENT - Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer or leased by the customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE - The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

GENERAL PROVISIONS Rate 100

IV. LIABILITY: (Cont.)

4. INDEMNIFICATION - Customer agrees to indemnify and hold Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE - In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

GENERAL PROVISIONS Rate 100

IV. LIABILITY: (Cont.)

5. FORCE MAJEURE - (Cont.)
The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

V. GENERAL TERMS AND CONDITIONS:

1. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for any service.

2. RATE OPTIONS - Where more than one rate schedule is available for the same class of service, the Company will assist the customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in twelve months unless there is a material change in the customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

3. RULES FOR APPLICATION OF GAS SERVICE:
   a. Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, may be served on the residential rate.

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

3. RULES FOR APPLICATION OF GAS SERVICE: (Cont.)

b. Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty parlors, master metered apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site (this is not an all-inclusive list).

c. The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

d. If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for nonresidential purposes as defined herein), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the Nonresidential rates.

4. DISPATCHING - Transportation customers will adhere to gas dispatching policies and procedures established by Company to facilitate transportation service. Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES - The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 - Manufactured Home Construction and Safety Standards) Subpart G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities. Contact your local Montana-Dakota Utilities Co. office for this information.

6. CONSUMER DEPOSITS - The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission rules.

   a. The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   b. The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided a prompt payment record has been established.

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

7. METERING AND MEASUREMENT:

a. Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. Company will test meters in accordance with applicable state utility rules and regulations.

b. Transportation customers agree to provide the cost of the installation of electronic measurement equipment to Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES - The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the application of a thermal factor to the volumes metered. This thermal factor consists of:

a. an altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

b. a Btu adjustment factor used to reflect the heating value of the gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT - The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and at a temperature base of sixty degrees Fahrenheit (60°F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

9. UNIT OF VOLUME FOR MEASUREMENT - (Cont.)
at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., copyright 1955, as amended or superseded. For handbilled accounts, application of supercompressibility factors will be waived on monthly billed volumes of 250 dk or less.

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY - Priority of Service from Highest to Lowest:
   a. Priority 1 - Firm sales and firm transportation services.
   b. Priority 2 - Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
   c. Priority 3 - Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.
   d. Priority 4 - Small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
   e. Priority 5 - Large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
   f. Priority 6 - Gas scheduled to clear imbalances.

   Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

   Montana-Dakota reserves the right to provide service to customers with a lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

11. LATE PAYMENT - Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE - A charge of $10.00 will be collected by the Company for each check charged back to the Company by a bank.

13. TAX CLAUSE - In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any sales, use or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

    The charges to be added to the customers' service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

14. UTILITY CUSTOMER SERVICES:

    a. The following services will be performed at no charge regardless of the time of performance:

        1. Fire and explosions calls.

        2. Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

        3. Maintenance or repair of Company-owned facilities on the customer's premises.

    b. The following service calls will be performed at no charge during the Company's normal business hours:

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

14. UTILITY CUSTOMER SERVICES: (Cont.)

1. Cut-ins and cut-outs.

2. Disconnecting of gas appliances permanently removed from service or in connection with cut-outs.

3. Lighting pilots, inspecting, and adjusting gas equipment in connection with establishing service when working cut-in orders.

4. Initial burner adjustment on residential gas burning appliances.

5. High bills or inadequate service complaints.

6. Location of underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

7. Pilot relighting, testing thermocouple for proper operation and any pilot cleaning that can be done without removing pilot assembly.

8. Service calls for routine cut-ins, when the order is received prior to 3:30 p.m. on a regular work day, requiring service on the date the order is received, will be considered as non-chargeable regardless if work is performed outside of normal working hours.

15. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS - For service requested by customers after the Company's normal business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and material at retail prices.

Customers requesting service after the Company's normal business hours will be informed of the after hour service rate and encouraged to have the service performed during normal business hours.

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

16. NOTICE TO DISCONTINUE GAS SERVICE - Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities in which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

17. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER - A fee of $18.00 will be collected for reconnecting gas sales or transportation service, during normal business hours, to any customer who has discontinued the same service at the same location during the preceding 12 month period. Standard overtime rates will apply after normal business hours.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the required electronic measurement equipment is necessary.

18. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS - All amounts billed for service are due when rendered and will be considered delinquent if not paid by due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $12.00 before restoring gas service which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours.

19. DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS - The Company reserves the right to discontinue service for any of the following reasons:

    a. In the event of customer use of equipment in such a manner as to adversely affect the company's equipment or service to others.

    b. In the event of tampering with the equipment furnished and owned by the Company.

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

19. DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS - (Cont.)

c. For violation of or noncompliance with the Company's rules on file with the Commission.

d. For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

e. For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying Company facilities.

The Company may collect a reconnect fee of $12.00 before restoring gas service which has been disconnected for the above causes.

20. UNAUTHORIZED USE OF SERVICE - Unauthorized use of service is defined as any deliberate interference such as tampering with a Company meter, pressure regulator, registration, connections, equipment, seals, procedures or records that result in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service, that has been terminated, without the Company's consent.

a. Examples of unauthorized use of service include the following, but are not limited to:

1) Bypass piping around meter.
2) Bypass piping installed in place of meter.

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

20. UNAUTHORIZED USE OF SERVICE - (Cont.)

3) Meter reversed.
4) Meter index disengaged or removed.
5) Service or equipment tampered with or piping connected ahead of meter.
6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
7) Gas being used after service has been discontinued by the Company.
8) Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

b. In the event that there has been unauthorized use of service, customer shall be charged for:

1) Time, material and transportation costs used in investigation.
2) Estimated charge for non-metered gas.
3) On-premise time to correct situation.
4) Any damage to Company property.

c. Customer service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid all charges as hereinafter set forth in this procedure:

1) All delinquent bills, if any.
2) The amount of any Company revenue loss attributable to said tampering.
3) Expenses incurred by the Company in replacing or repairing the meter or other appliance, costs incurred in preparation of the bill, plus costs as outlined in number 20.b. above.
4) Reconnection fee applicable.
5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

21. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
Rate 102 - Residential Rate for Regular Employees
Rate 119 - Interruptible Gas Service Extension Policy
Rate 120 - Firm Gas Service Extension Policy
Rate 124 - Service Lines

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
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STATE OF NORTH DAKOTA
GAS RATE SCHEDULE

NDPSC Volume 6
Original Sheet No. 44
Cancelling Vol 5, 1st Rev Sheet No. 44

RATE FOR RESIDENTIAL GAS SERVICE FOR REGULAR EMPLOYEES
OF MONTANA-DAKOTA UTILITIES CO., MDU RESOURCES GROUP, INC.
AND WHOLLY-OWNED SUBSIDIARIES OF MDU RESOURCES GROUP, INC. Rate 102

The rate for residential gas service for regular employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly-owned subsidiaries of MDU Resources Group, Inc., shall be computed at the applicable rate, and the amount reduced by 33 1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular employee who has been continuously employed at least six months and is the principal support of the household in which employee resides, or is the spouse of the principal support.

Date Filed: November 10, 1994
Effective Date: Service Rendered on and After November 15, 1994

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: PU-399-94-297

INTERRUPTIBLE GAS SERVICE EXTENSION POLICY Rate 119

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide interruptible sales or interruptible transportation service to customers is as follows:

1. Contribution

a. Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, service stub(s), service line(s) complete where applicable, regulators, meters (excluding electronic measurement equipment), any required payments made by the Company to the transmission pipeline to accommodate the extensions, and other costs as adjusted for federal and state income taxes.

b. The contribution shall be made by:

i. A one-time payment prior to construction or,

ii. The customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the total contribution required prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for a five-year period commencing at the plant in service date, and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists for the subject project, the surety or guarantor shall pay the Company for such contribution requirement, or

iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

d. Electronic measurement equipment costs shall be subject to the terms and conditions specified in Transportation Service Rates 81, 82, 84.

INTERRUPTIBLE GAS SERVICE EXTENSION POLICY Rate 119

2. Refund

a. If within the five-year period from the extension(s) in service date, the total of the customer's contribution and actual margin paid to the Company equals or exceeds the total present value of the revenue requirement associated with the extension, Company shall refund the amount exceeding the revenue requirement on the following basis:

i. Annually, beginning at the 2nd anniversary of the extension(s) in service date, the Company will refund to the customer, the amount exceeding the total present value of the revenue requirement at a rate of 50% of the current year margin associated with the customer's actual throughput.

ii. Customers who have posted a bond, letter of credit, or a written guarantee commitment will be notified of any reduction in surety or guarantee requirements based on the above calculation.

iii. No refunds will be made for amounts less than $25.

b. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

c. No refund shall be made by the Company after the five-year refund period has expired, and in no case shall the refund, excluding interest, exceed the amount of contribution made by the customer.

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1st Revised Sheet No. 62
Cancelling Original Sheet No. 62

FIRM GAS SERVICE EXTENSION POLICY Rate 120

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales or firm transportation service to customers is as follows:

A. General Rules and Regulations Applicable to all Firm Service Extensions

1. An extension will be constructed without a contribution if the estimated capital expenditure is cost justified as defined in paragraph A.3.

2. The Company may require customer or developer cost participation if the estimated capital expenditure is not cost justified.

3. The extension will be considered cost justified if the calculated maximum allowable investment equals or exceeds the estimated capital expenditure using the following formula:

Maximum Allowable Investment=

$$\frac{\text{Annual Base Rate + (Project Estimated 3rd Year Annual Dk x Unit Margin)}}{\text{LARR + O\&M}}$$

where: LARR = Levelized Annual Revenue Requirement Factor of 16.084%
O&M = Operating and Maintenance Factor of 3.870%

4. Cost of the extension shall include the gas main extension(s), valves, service stub(s), or service line(s) complete where applicable, any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs excluding the distribution meter and regulator.

The service stub is that portion of the gas service extending from the main to the private property line or easement boundary.

The service line complete is that portion of the gas service extending 150 feet from the main to the connection at the house regulator and/or meter for those customers served in the communities set forth in Rate Zone 2.

The service line is that portion of the gas service extending from the service stub to the connection at the house regulator and/or meter. Service lines are installed at customer's expense and are owned by and shall be maintained at customer's expense.

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
23
JUN - 9 1999
CASE NO. PU-349-99-174

Date Filed: May 18, 1999 Effective Date: _____

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.: _____

FIRM GAS SERVICE EXTENSION POLICY Rate 120

A. General Rules & Regulations Applicable to all Firm Service Extensions (Cont.)

5. Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer or the developer and Company.

6. A refund will be made only when there is a reduction in the amount of contribution required within a five-year period from the extension(s) in service date. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

No refund shall be made by Company after the five-year refund period and in no case shall the refund excluding interest, exceed the amount of the contribution.

B. Customer Extensions

Cost participation for extensions where customers will be immediately available for service is as follows:

1. Contribution -

a. When a contribution is required, the customer(s) shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with paragraph A.3.

b. The contribution shall be made by:

i. A one-time payment prior to construction, or

ii. Payment of 25% of the contribution prior to construction and the balance in no more than twenty-four equal monthly installments. If customer discontinues service within the twenty-four month period, the balance will be due and payable upon discontinuance of service, or

iii. Customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement

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FIRM GAS SERVICE EXTENSION POLICY Rate 120

B. Customer Extensions (Cont.)

1. b. iii. exists in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement, or

iv. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

d. If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment.

e. The recalculated contribution requirement shall be collected from the new applicant(s).

2. Refund -

a. The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Customers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

b. No refunds will be made until the new applicants begin taking service from the Company.

If the addition of new customers will increase the contribution required from existing customers(s), the extension will be considered a new extension and treated separately.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 23 - 8 1999
CASE NO. PU-399-99-174

Date Filed: May 18, 1999 Effective Date:

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Case No.:

MONTANA-DAKOTA UTILITIES CO.
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STATE OF NORTH DAKOTA
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Substitute 1st Revised Sheet No. 62.3
Cancelling Original Sheet No. 62.3

FIRM GAS SERVICE EXTENSION POLICY Rate 120

B. Customer Extensions (Cont.)

3. Incremental Expansion Surcharge -

a. The Company, in its sole discretion, may offer an Incremental Expansion Surcharge (Surcharge) to a project consisting of 10 or more customers requesting service when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. If the company and customers mutually agree that the project will be funded through a Surcharge, the project will be designated an expansion area and the Surcharge will be applicable to all connections within the expansion area. The contribution requirement to be collected under the Surcharge shall be the amount of the capital expenditure in excess of the Maximum Allowable Investment determined in accordance with ¶A.3.

i. A minimum up-front payment of $100.00 will be collected from each customer who signs an agreement to participate in the expansion.

ii. For projects that are expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus $1.50 per dk.

iii. For projects that are not expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus a commodity charge designed to provide recovery of the contribution requirement in a five year period.

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b. The Surcharge shall remain in effect until the net present value of the contribution requirement, calculated using a discount rate equal to the overall rate of return authorized in the last rate case, is collected.

c. The Surcharge shall apply to all customers connecting to natural gas service within the expansion area until the contribution requirement is satisfied.

d. The net present value of the Surcharge will be treated as a contribution-in-aid of construction for accounting purposes.

C. Developer Extensions

Cost participation may be required for extensions such as a subdivision or mobile home court, in which a developer is installing roads, utilities, etc., before housing is built.

1. Contribution -

Date Filed: May 18, 1999 Effective Date: _____

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

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FIRM GAS SERVICE EXTENSION POLICY Rate 120

C. Developer Extensions (Cont.)

a. When a contribution is required, the developer shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with paragraph A.3.

b. The contribution shall be made by:

i. A one-time payment prior to construction, or

ii. Developer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or a written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the subject project based on a recalculated maximum expenditure, the surety shall reimburse the Company for such recalculated contribution requirement, or

Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

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c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

2. Refund -

a. If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment. Such recalculation shall be done annually based upon the anniversary of the extension(s) in service date.

FIRM GAS SERVICE EXTENSION POLICY Rate 120

C. Developer Extensions (Cont.)

b. The Company will refund to the developer the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Developers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guaranty requirements.

2. c. If the addition of new customer(s) will increase the contribution required from the developer, the extension will be considered a new extension and treated separately.

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NEW INSTALLATION, REPLACEMENT, RELOCATION AND
REPAIR OF GAS SERVICE LINES Rate 124

A. NEW INSTALLATION OF COMPANY-OWNED SERVICE LINES - The Company will install, at its expense, a service line extending up to 150 feet from the main to the connection at the house regulator and/or meter for those customers served in the communities set forth in Rate Zone 2. A contribution may be required for that portion of the service line exceeding 150 feet in accordance with the Firm Gas Service Extension Policy Rate 120.

B. The following will apply to all new customer-owned gas service lines, and to the replacement, relocation and repair of all gas service lines on private property.

1. The customer shall be charged for a new service line on the basis of direct costs to the Company including material, labor, transportation, etc. Such costs shall include ordinary payroll and general overhead loadings. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

2. If the customer's service line is less than 25 years old, and is coated steel or plastic pipe, such line shall be pressure tested in accordance with the Company's rules for pressure testing. If the service line is found to be leaking due to faulty installation or due to a lack of cathodic protection, has damaged coating, surface pitting, etc., the line will be repaired or replaced at no cost to the customer. All other repairs shall be at customer's expense.

3. For coated steel or plastic pipe service lines more than 25 years old which need to be repaired and/or replaced and for bare pipe service lines of any age, the customer shall be charged in accordance with B.1. above.

   In accordance with Company Standards, service line replacements will be constructed with outside risers and meters. Such reconstruction will nearly always involve minor changes in inside piping. The inside piping changes may be incorporated into the total footage to be billed as provided in B.1. above.

NEW INSTALLATION, REPLACEMENT, RELOCATION AND
REPAIR OF GAS SERVICE LINES Rate 124

4. Where the customer's gas service line must be replaced because the mains are being relocated (alley to street or street to alley), such line change or relocation will be made at the Company's expense if the service line is coated steel or plastic pipe and is less than 25 years old. If the line is older and passes the required pressure test, the replacement will be made at the Company's expense. If such older line does not pass the required pressure test, the line shall be replaced at the customer's expense except that the customer shall be charged only for the lesser of: (a) the equivalent length of the old service line or (b) the actual length of the new service line if it is shorter than the older service line being replaced. The basis for billing the customer shall be as outlined in B.1. above.

5. The customer has the option of waiving the pressure test and receiving a credit equal to the cost of the pressure test against the installed cost of a new service line.

6. Where service line location changes are made due to building encroachments (a building is being constructed or is already located over a service line, etc.), or due to the necessity to increase the size and capacity of an existing service line because of increased demand, the customer shall be charged for on the basis of direct costs incurred by the Company, as outlined in B.1. above.

7. Whenever a service line is damaged by excavating and/or earth-moving equipment, etc., and is either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis including ordinary payroll and general overhead loadings. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor. Damages done by the customer or someone working directly for him shall be paid for by the customer. Such charges shall be made regardless of the age of the damaged service line.

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Date Filed: April 12, 2002 **Effective Date:**

Issued By: Donald R. Ball
Director of Regulatory Affairs **Case No.:**

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COMMUNITIES SERVED

NATURAL GAS SERVICE

Dakota Heartland Region

Apple Valley	Devils Lake	Mandan	Steele
Barlow	Eldridge	Max	Surrey
Berthold	Fort Totten	Medina	Tappen
Bismarck*	Garrison	Minot	Turtle Lake
Burlington	Glen Ullin	New Rockford	Underwood
Carrington	Grafton	New Salem	Valley City
Cavalier	Jamestown	Park River	Walhalla
Cleveland	Langdon	Riverdale	Washburn
Dawson	Lincoln	Sandborn	Wilton
Des Lacs	Linton	Sheyenne	

Badlands Region

Alexander	Golva	Ray	Taylor
Arnegard	Hebron	Regent	Tioga
Beach	Killdeer	Rhame	Trenton
Belfield	Lefor	Richardton	Watford City
Bowman	Lignite	Ross	Wheelock
Dickinson*	Marmarth	Sentinel Butte	White Earth
East Fairview	Mott	Springbrook	Williston
Epping	New England	South Heart	
Gladstone	Palermo	Stanley	

PROPANE SERVICE

Badlands Region
Hettinger

*Designates Region Office

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RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	PGA Items	Total Rate/ Dk
Residential Rate 60	4	$0.39 per day	$0.432	$2.907	$3.339
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$2.907	$3.045
Interruptible Service			$0.120	$1.922	$2.042
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.80 per day			
Meters rated > 500 cubic feet		$1.70 per day	$0.410	$2.907	$3.317
Small Interruptible Gas Rate 71	14	$100.00 per month	Per Contract	$1.653	Per Contract
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		$0.80 per day			
Meters rated > 500 cubic feet		$1.70 per day			
Winter Gas Usage			$0.410	$3.538	$3.948
Summer Gas Usage			$0.410	$2.416	$2.826
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.366		
Minimum			$0.102		
Fuel Charge				$0.018	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.018	
Large Interruptible Gas Rate 85	27	$675.00 per month	Per Contract	$1.653	Per Contract
Residential Propane Rate 90	32	$0.39 per day	$0.432	$2.882	$3.314
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		$0.80 per day			
Meters rated > 500 cubic feet		$1.70 per day	$0.410	$2.882	$3.292

Date Filed: April 12, 2002 **Effective Date:**

Issued By: Donald R. Ball
Directory of Regulatory Affairs **Case No.:**

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RATE SUMMARY SHEET

Miscellaneous Charges	Amount
Late Payment	1% per month
Returned Check	$20.00 per check
Minimum reconnection charge after termination for nonpayment or other causes -During normal business hours -After normal business hours	 $30.00 Current service labor rate per hour
Reconnection charge applicable to seasonal or temporary customers -During normal business hours -After normal business hours	Basic Service Charge applicable during the period while service was not being used. Minimum- $30.00 Minimum- Current service labor rate per hour
Reconnection charge applicable to transportation customers when remote data acquisition equipment must be reinstalled	$160.00

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RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$.39 per day
Distribution Delivery Charge:	$.432 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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AIR FORCE Rate 64

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate:

Basic Service Charge:	
Minot Air Force Base	$1,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$135.00 per month
Distribution Delivery Charge:	
Firm Service	$.138 per dk
Interruptible Service	$.120 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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AIR FORCE Rate 64

General Terms and Conditions:

1. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If the customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm Service distribution delivery charge and cost of gas rates set forth above, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

2. CONTRACT – Terms of service other than the rate shall be specified in contracts between Minot Air Force Base, and PAR and the Company.

3. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$.80 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.410 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$100.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$1.213 per dk	$.366 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the cost of Purchased Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

General Terms and Conditions:

1. PRIORITY OF SERVICE – Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

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SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS – Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS –Remote data acquisition equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder.

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$.80 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.410 per dk
Cost of Gas:	
Winter- Bills rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Bills rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

General Terms and Conditions:

1. The customer agrees to contract for service under the Optional Seasonal General Gas Service Rate 72 for a minimum of one year.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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TRANSPORTATION SERVICE Rates 81 and 82

Availability:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through Company's distribution facilities. In order to obtain transportation service, customer must qualify under an applicable gas transportation service rate; meet the general terms and conditions of service provided hereunder; and enter into a gas transportation agreement upon request by the Company.

The transportation services are as follows:

Small Interruptible General Gas Transportation Service Rate 81:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point, whose average use of natural gas will not exceed 100,000 dk annually and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Small Interruptible General Gas Service Rate 71. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

Large Interruptible General Gas Transportation Service Rate 82:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually metered at a single delivery point, and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Large Interruptible General Gas Service Rate 85. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

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TRANSPORTATION SERVICE Rates 81 and 82

Rate:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:
Rate 81 $150.00 per month
Rate 82 $725.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$0.366	$0.298
Minimum Rate per dk	$0.102	$0.061
Balancing Charge per dk	$0.300	$0.300

Fuel Charge:
Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See Rate Summary Sheet t for currently effective charge.

General Terms and Conditions:

1. CRITERIA FOR SERVICE: In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

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2. REQUEST FOR GAS TRANSPORTATION SERVICE:
   a. To qualify for gas transportation service a customer must request the service pursuant to the provisions set forth herein. The service shall be provided only to the extent that the Company's existing operating capacity permits.

   b. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.10.

3. MULTIPLE SERVICES THROUGH ONE METER:
   a. In the event customer desires firm sales service in addition to gas transportation service, customer shall request such firm volume requirements, and upon approval by Company, such firm volume requirements shall be set forth in a firm service agreement. For billing purposes, the level of volumes so specified or the actual volume used, whichever is lower shall be billed at Rate 70. Volumes delivered in excess of such firm volumes shall be billed at the applicable gas transportation rate. Customer has the option to install at their expense, piping necessary for separate measurement of sales and transportation volumes.

   b. The customer shall pay, in addition to charges specified in the applicable gas transportation rate schedule, charges under all other applicable rate schedules for any service in addition to that provided herein (irrespective of whether the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE – Company shall have the right to curtail or interrupt deliveries without being required to give previous notice of intention to curtail or interrupt, whenever, in its judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

5. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken above that received on customer's behalf, shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

6. NON-DELIVERED VOLUMES/PENALTY:
   a. In the event customer uses more gas than is being delivered to the Company's interconnection with the delivering pipeline(s) (receipt point), customer shall pay an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the same receipt point, any payment or overrun penalties the Company is required to make shall be allocated on a pro rata basis among such customers on the basis of each customer's use of gas in excess of available volumes.

   b. In the event the customer's gas is not being delivered to the receipt point for any reason and the customer continues to take gas, the customer shall be subject to any applicable penalties or charges set forth in Paragraph 6.a. Gas volumes supplied by Company will be charged at Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas). The Company is under no obligation to notify customer of non-delivered volumes.

c. In the event customer's transportation volumes are not available for any reason, customer may take interruptible sales service if such service is available. The availability of interruptible sales service shall be determined at the sole discretion of the Company.

7. ELECTION OF SERVICE – Prior to the initiation of service hereunder, the customer shall make an election of its requirements under each applicable rate schedule for the entire term of service. If mutually agreed to by Company and customer, the term of service may be amended. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under the appropriate sales rate schedule for the customer's operations.

   Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge as specified in Rate 100, §V.17.

8. BALANCING:
   a. To the extent practicable, customer and Company agree to the daily balancing of volumes of gas received and delivered on a thermal basis. Such balancing is subject to the customer's request and the Company's discretion to vary scheduled receipts and deliveries within existing Company operating limitations.

      If, at the end of a billing month, the accumulated difference between actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer exceeds 4% of that month's scheduled receipts, resulting in a negative imbalance (i.e., deliveries exceed scheduled receipts), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, the customer shall then be billed, in addition to the applicable transportation rate,

a penalty for the under nominated volume exceeding 4% at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas). The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume on which a penalty was imposed.

If, at the end of a billing month, the accumulated difference between nominated (scheduled) receipts on behalf of such customer and actual gas deliveries to the customer exceeds 4% of that month's scheduled receipts resulting in a positive imbalance (i.e., scheduled receipts exceed deliveries), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, (1) the Company may adjust the volume of gas received on behalf of the customer so as to eliminate the prior period over nomination exceeding 4% up to 10% and (2) the Company shall retain the over nomination of gas exceeding 10% free and clear of any adverse claims relating thereto when such accumulated difference exceeds 50 dk. The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume retained.

b. In the event customer's imbalance causes the Company to incur a balancing penalty from its interconnecting pipeline(s), customer shall pay any penalty payments or overrun charges the Company is required to make under the terms of its contract(s) with interconnecting pipeline(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the

same interconnection with a delivering pipeline, any payment or overrun penalties the Company is required to make shall be apportioned among such customers on the basis of each customer's contribution toward the imbalance.

c. Customer's nomination made to clear imbalances will be subject to the priority of service and allocation of capacity provisions set forth in Rate 100, §V.10 and the penalties for failure to curtail or interrupt use of gas set forth in Paragraph 5 of this rate schedule.

d. Termination of the gas transportation service shall not relieve Company and customer of the obligation to correct any quantity imbalances hereunder or customer of the obligation to pay money due hereunder to Company.

e. The Company may waive any penalty associated with Company adjustments to end-use customer nominations in those instances where the Company, due to operating limitations, is required to adjust end-use transportation customer nominations and such Company adjustments create a penalty situation, or preclude a customer from correcting an imbalance which results in a penalty.

9. NOMINATION VARIANCE CHARGE – The customer shall pay any payments the Company must make to its interconnecting pipeline(s), as a result of nomination variance penalties caused by customer's nomination variances. Such penalties will be allocated on the basis of each customer's contribution toward the nomination variance.

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TRANSPORTATION SERVICE Rates 81 and 82

10. METERING REQUIREMENTS:
    a. Remote data acquisition equipment required by the Company for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by the customer. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. Company may remove such equipment when service hereunder is terminated.

    b. The customer shall provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

    c. The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

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TRANSPORTATION SERVICE Rates 81 and 82

11. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper or agent shall advise Company's gas nominations center, by 11:30 a.m. Central Clock Time, of the dk requirements customer has requested to be delivered at each delivery point the following day. Customer's daily nomination shall be its best estimate of the expected utilization for the gas day. Unless other arrangements are made, customer will be required to nominate for the non-business days involved prior to weekends and holidays.

    b. All nominations should include shipper and/or agent defined begin and end dates. Shippers and/or agents may nominate for periods longer than 1 day, provided the nomination begin and end dates are within the term of the service agreement.

    c. The Company has the sole right to refuse receipt of any volumes which exceed the maximum daily contract quantity and at no time shall the Company be required to accept quantities of gas for a customer in excess of the quantities of gas to be delivered to customer. If total nominated receipts exceed total deliveries at receipt points where more than one customer is receiving service, nominations will be allocated on a pro rata basis.

    d. At no time shall Company have the responsibility to deliver gas in excess of customer's nomination.

    e. In the event that more than one customer is receiving gas from the same shipper and/or agent at the same receipt point, any reduction in nominated volumes will be allocated on a pro rata basis, unless Company and shipper(s) and/or agent(s) have agreed to a predetermined allocation procedure.

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12. WARRANTY – The customer, customer's agent, or customer's shipper warrants that it will have title to all gas it tenders or causes to be tendered to the Company, and such gas shall be free and clear of all liens and adverse claims and the customer, customer's agent, or customer's shipper shall indemnify the Company against all damages, costs, and expenses of any nature whatsoever arising from every claim against said gas.

13. FACILITY EXTENSIONS - If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities required to furnish firm gas service, the customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. Company may remove such facilities when service hereunder is terminated.

14. PAYMENT – Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

15. BILLING ERROR – In the event an error is discovered in any bill that the Company renders to customer, such error shall be adjusted within a period not to exceed 6 months from the date the billing error is first discovered.

16. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for service hereunder.

17. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

This rate schedule shall not apply for service to U.S. Government installations, which are covered by separate special contracts.

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge	$675.00 per month	
Distribution Delivery Charge	Maximum $1.003 per dk	Minimum $.298 per dk
Cost of Gas	Determined Monthly- See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

General Terms and Conditions:

1. PRIORITY OF SERVICE – Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 90 days prior to the end of the initial term. Absent execution of such termination notice, the agreement shall continue for additional terms of equal length until written notice is given as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

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4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS –Remote data acquisition equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder.

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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PURCHASED GAS COST ADJUSTMENT Rate 88

1. **Applicability:**
This rate schedule constitutes a purchased gas cost adjustment (PGA) provision and specifies the procedure to be utilized to adjust the rates for gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of gas supply, (b) amortization of the Unrecovered Purchased Gas Cost Account and (c) market based pricing differential.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the PGA shall be bills rendered on and after the first date of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file a PGA to reflect changes in its average cost of gas supply only when the amount of change in such PGA is at least 10 (ten) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. **Purchased Gas Cost:**
(a) The monthly PGA shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent PGA. The cost of gas supply shall be the sum of all costs incurred in obtaining gas for general system supply. General system supply is defined as gas available for use by all customers served under retail sales rate schedules. The cost of gas supply shall include, but not be limited to, all demand, commodity, storage, gathering, and transportation charges incurred by Montana-Dakota for such gas supply, the overall rate of return on prepaid demand and commodity charges and gas storage balances required to maintain the system gas supply and hedging program gains, losses and transaction costs related to system gas supply.

(b) The PGA shall be computed as follows:

(1) Demand costs shall include all annual gathering, transportation and storage demand charges at current rates.

(2) Commodity costs shall include all annual gathering, transportation and storage charges at current rates.

(3) The gas commodity cost shall reflect all commodity related gas costs estimated to be in effect for the month the PGA will be in effect and annual dk requirements.

(4) The return on prepaid demand and commodity balances and storage balances shall be computed on an annual basis at the overall rate of return on rate base.

The cost per dk for the month is the sum of the above divided by annual, weather normalized dk deliveries adjusted to reflect losses.

(c) Monthly gas costs shall be calculated as follows:

(1) Demand costs for firm customers shall be apportioned to all state jurisdictions served by Montana-Dakota on the basis of the overall ratio of each state's Maximum Daily Delivery Quantity (MDDQ).

(2) Demand costs for interruptible sales customers shall be stated on a 100% load factor basis.

(3) All commodity costs and other costs associated with the acquisition of gas for general system supply shall be apportioned to each state on the basis of total dks sold in each state, regardless of the actual points of delivery of such gas.

(4) The return requirement related to prepaid demand and commodity charges and gas storage balances shall be included on a per dk basis. The prepaid demand and storage balances shall be apportioned to all states on the basis of each state's MDDQ. The prepaid commodity charges shall be apportioned to all states on the basis of annual dks sold in each state. The unit cost shall be calculated using a thirteen-month average balance and the currently authorized return on rate base.

(5) All costs related to specific end-use transactions shall not be included in the cost of gas supply determination but shall be directly billed to the customer(s) contracting for such service.

(d) The PGA shall be applied to each of Montana-Dakota's rate schedules recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. Surcharge Adjustment:

(a) All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on May 1 of each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Gas Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

5. Unrecovered Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in a Purchased Gas Cost Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for gas supplies, which were paid during any period after the effective date of the most recent general rate case, but not yet included in sales rates.

(3) Refunds received from supplier(s) with respect to gas supply. Such refunds received shall be credited to the Unrecovered Purchased Gas Cost Account.

(4) Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

(5) Demand costs recovered from the interruptible sales customers will be credited to the residential and firm general service customers.

(b)

(1) The amount to be included in the Unrecovered Purchased Gas Cost Account in order to reflect the items specified in Subsections 5(a)(1), (2), and (3) shall be calculated as follows:

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(i) Montana-Dakota shall first determine each month the unit cost for that month's natural gas supply as adjusted to levelize demand charges.

Such adjustment to levelize supplier(s) demand charges shall be calculated as follows:

The supplier's annual (calendar or fiscal) demand charges, which are payable in equal monthly payments shall be accumulated in a prepaid account (FERC Account 165). Each month a portion of such accumulated prepaid amount shall be amortized to cost of natural gas purchased (FERC Account 804). Such monthly amortization shall be based on a rate calculated by dividing the annual supplier(s) demand charges by projected annual natural gas sales units (calendar or fiscal, as appropriate). The resulting product shall then be multiplied by the projected natural gas unit sales for the current month. Such amount shall constitute the monthly amortization of prepaid supplier(s) demand charges to cost of natural gas supply.

(1)

(ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for gas supply which is reflected in the currently effective PGA.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Gas Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Gas Cost Account, Account 191, at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The amount to be included in Account 191 for carrying charges shall be determined as follows:

Each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge; which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Unrecovered Purchased Gas Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(b) Reduction of Amounts in the Unrecovered Purchased Gas Cost Account:

(1) The amounts in the Unrecovered Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Gas Cost Account specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Unrecovered Purchased Gas Cost Account specified in Subsection 5(a)(4).

6. Market-Based Pricing Differential:

(a) At the time of each surcharge adjustment, the Company will compute a credit to residential and firm general service rates based on 50% of all distribution delivery charge revenues received from small interruptible sales and large interruptible sales customers in excess of the authorized minimum distribution delivery charge rate approved in the most recent general rate case.

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(b) The unit adjustment shall be determined by dividing the balance resulting under Subsection 6(a) by the residential and firm general service sales volumes estimated to be sold during the 12 months following the effective date of each adjustment.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file each PGA at least 20 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised PGA sheets identifying the amounts of the adjustments and the resulting currently effective PGA rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant pipeline tariff sheets supporting costs claimed.

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RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$.39 per day
Distribution Delivery Charge:	$.432 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$.80 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.410 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

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FIRM GENERAL PROPANE SERVICE Rate 92

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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PURCHASED PROPANE COST ADJUSTMENT Rate 99

1. **Availability:**
This rate schedule constitutes a purchased propane cost adjustment (PCA) provision and specifies the procedure to be utilized to adjust the rates for propane gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of propane supply and (b) amortization of the Unrecovered Purchased Propane Cost Account.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the PCA shall be bills rendered on and after the first day of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file a PCA to reflect changes in its average cost of propane supply only when the amount of such change in PCA is at least 10 (ten) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. **Purchased Propane Cost:**
(a) The monthly PCA shall reflect changes in Montana-Dakota's cost of propane supply as compared to the cost of propane supply approved in its most recent PCA . The cost of propane supply shall include, but not be limited to, all commodity and transportation charges incurred by Montana-Dakota for such propane supply.

(b) The propane commodity cost shall reflect all commodity related propane costs estimated to be incurred for the month the PCA will be in effect and estimated dk purchases.

The unit cost per dk for the month shall be the commodity costs divided by estimated dk purchases for the month.

4. **Surcharge Adjustment:**
All propane sales schedules shall be subject to a Surcharge Adjustment to be effective on May 1 each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Propane Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

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PURCHASED PROPANE COST ADJUSTMENT Rate 99

5. Unrecovered Purchased Propane Cost Account:

(a) Items to be included in the Unrecovered Purchased Propane Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for propane supply which Montana-Dakota is unable to reflect in a Purchased Propane Cost Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for propane supplies that were paid during any period after the effective date of the most recent approved rates, but not yet included in propane sales rates.

(3) Carrying charges or credits.

(b)

(1) The amount to be included in the Unrecovered Purchased Propane Cost Account in order to reflect the items specified in Subsections 5(a)(1) and (2) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's propane supply.

(ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for propane supply, which is reflected in the currently effective PCA.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each propane rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Propane Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Propane Cost Account, Account 191, as follows:

Each month, Account 191 shall be debited (on a debit balance) or credited (on a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance on Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The carrying charges shall be accrued in a supplementary Unrecovered Purchased Propane Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in the Unrecovered Purchased Propane Cost Account:

(1) The amounts in the Unrecovered Purchased Propane Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Propane Cost Account specified in Subsections 5(a)(1) and (2) and the amounts in the supplementary Unrecovered Purchased Propane Cost Account specified in Subsection 5(b)(2)(ii).

6. Time and Manner of Filing:

(a) Montana-Dakota shall file each PCA at least 10 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised PCA sheets identifying the amounts of the adjustments and the resulting currently effective PCA rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant material supporting costs claimed.

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I. **PURPOSE:**

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Service Commission of North Dakota and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. **DEFINITIONS:**

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

AGENT – The party authorized by the transportation service customer to act on that customer's behalf.

APPLICANT – A customer requesting Company to provide service.

COMMISSION – Public Service Commission of the State of North Dakota.

COMPANY – Montana-Dakota Utilities Co.

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT – A reduction of transportation or retail natural gas service deemed necessary by the Company. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

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CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by Company at one location and at one point of delivery unless otherwise expressly in these rules or in a rate schedule.

DELIVERY POINT – The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on customer's premises.

GAS DAY – Means a period of twenty-four consecutive hours, beginning and ending at 9:00 a.m. Central Clock Time.

INTERRUPTION – A cessation of transportation or retail natural gas service deemed necessary by Company.

NOMINATION – The daily dk volume of natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

PIPELINE – The transmission company(s) delivering natural gas into company's system.

RATE – Shall mean and include every compensation, charge, fare, toll, rental and classification, or any of them, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT – The intertie between Company and the interconnecting pipeline(s) at which point Company assumes custody of the gas being transported.

SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.

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III. **CUSTOMER OBLIGATION:**

1. APPLICATION FOR SERVICE – A customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. The Company may refuse a customer or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses gas service in the absence of application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

   Any customer may be required to make a deposit as required.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at Company's sole discretion, Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will ensure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

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3. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

4. COMPANY PROPERTY – The customers shall exercise reasonable diligence in protecting the Company's property on their premises, and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

5. INTERFERENCE WITH COMPANY PROPERTY – The customer shall not disconnect, change connections, make connections or otherwise interfere with Company's meters or other property or permit same to be done by other than the Company's authorized employees.

6. RELOCATED LINES - Where Company facilities are located on a public or private utility easement and there is a building encroachment(s), over gas facilities (Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

7. NOTIFICATION OF LEAKS – The customer shall immediately notify the Company at its office of any escape of gas in or about the customer's premises.

8. TERMINATION OF SERVICE – All customers are required to notify the Company, to prevent their liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

9. REPORTING REQUIREMENTS – Customer shall furnish Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

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IV. **LIABILITY**

1. CONTINUITY OF SERVICE – The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

2. CUSTOMER'S EQUIPMENT – Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer or leased by the customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE – The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE – In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor

shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorization from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

V. **GENERAL TERMS AND CONDITIONS:**

1. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for any service.

2. RATE OPTIONS – Where more than one rate schedule is available for the same class of service, the Company will assist the customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in twelve months unless there is a material change in the customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

2. RULES FOR APPLICATION OF GAS SERVICE:
   (a) Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, may be served on the residential rate.

   (b) Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty parlors, master metered apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site (this is not an all-inclusive list).

   (c) The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

   (d) If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for

(e) nonresidential purposes as defined herein), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by Company to facilitate transportation service. Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Homes Construction and Safety Standards) Subpart G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission rules.

   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (b) The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to

the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided prompt payment record has been established.

7. METERING AND MEASUREMENT:
   (a) Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. Company will test meters in accordance with applicable state utility rules and regulations.

   (b) Transportation customers agree to provide the cost of the installation of electronic measurement equipment to Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the

application of a thermal factor to the volumes metered. This thermal factor consists of:

(a) An altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

(b) A Btu adjustment factor used to reflect the heating value of the gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT – The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and at a temperature base of sixty degrees Fahrenheit (60°F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AAGA-3/NX-19, as amended, supercompressibility calculation. For handbilled accounts, application of supercompressibility factors will be waived on monthly-billed volumes of 250 dk or less.

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from Highest to Lowest:
    (a) Priority 1 – Firm sales services.
    (b) Priority 2 – Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
    (c) Priority 3 – Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.

(d) Priority 4 – Small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
(e) Priority 5 – Large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
(f) Priority 6 – Gas scheduled to clear imbalances.

Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE – A charge of $20.00will be collected by the Company for each check charged back to the Company by a bank.

13. TAX CLAUSE – In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any sales,

use or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

The charges to be added to the customer's service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

14. UTILITY CUSTOMER SERVICES:
    (a) The following services will be performed at no charge regardless of the time of performance:

        (1) Fire and explosions calls.

        (2) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

        (3) Maintenance or repair of Company-owned facilities on the customer's premises.

    (b) The following service calls will be performed at no charge during the Company's normal business hours:

        (1) Cut-ins and cut-outs.

        (2) Disconnecting of gas appliances permanently removed from service or in connection with cut-outs.

        (3) Lighting pilots, inspecting, and adjusting gas equipment in connection with establishing service when working cut-in orders.

        (4) Initial burner adjustment on residential gas burning appliances.

(5) High bills or inadequate service complaints.

(6) Location of underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

(7) Pilot relighting, testing thermocouple for proper operation and any pilot cleaning that can be done without removing pilot assembly.

(8) Service calls for routine cut-ins, when the order is received prior to 12:00 p.m. on a regular work day, requiring service on the date the order is received, will be considered as non-chargeable regardless if work is performed outside of normal working hours.

15. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and materials at retail prices.

    Customers requesting service after the Company's normal business hours will be informed of the after hour service rate and encouraged to have the service performed during normal business hours.

16. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service disconnected shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

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17. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER –A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged the Basic Service Charge applicable during the period while service was not being used or a minimum of $30.00. The minimum will be based on standard overtime rates for reconnection of service after normal business hours.
Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the required electronic measurement equipment is necessary.

18. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $30.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours.

19. DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS – The Company reserves the right to discontinue service for any of the following reasons:

    (a) In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    (b) In the event of tampering with the equipment furnished and owned by the Company.

    (c) For violation of or noncompliance with the Company's rules on file with the Commission.

(d) For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

(e) For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying Company facilities.

The Company may collect a reconnect fee of $30.00 before restoring gas service, which has been disconnected for the above causes.

20. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with a Company meter, pressure regulator, registration, connections, equipment, seals, procedures or records that result in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.

(a) Examples of unauthorized use of service include the following, but are not limited to:

(1) Bypass piping around meter.
(2) Bypass piping installed in place of meter.

(3) Meter reversed.
(4) Meter index disengaged or removed.
(5) Service or equipment tampered with or piping connected ahead of meter.
(6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
(7) Gas being used after service has been discontinued by the Company.
(8) Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

(b) In the Event that there has been unauthorized use of service, customer shall be charged for:

(1) Time, material and transportation costs used in investigation.
(2) Estimated charge for non-metered gas.
(3) On-premise time to correct situation.
(4) Any damage to Company property.

(c) Customer service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid all charges as hereinafter set forth in this procedure.

(1) All delinquent bills, if any.
(2) The amount of any Company revenue loss attributable to said tampering.
(3) Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in number 20.b above.
(4) Reconnection fee applicable.
(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

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GENERAL PROVISIONS Rate 100

21. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
    Rate 102 – Residential Rate for Regular Employees
    Rate 119 – Interruptible Gas Service Extension Policy
    Rate 120 – Firm Gas Service Extension Policy
    Rate 124 – Service Lines

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RESIDENTIAL GAS SERVICE FOR REGULAR EMPLOYEES
Rate 102

The bill for residential gas service for regular employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly owned subsidiaries of MDU Resources Group, Inc., shall be computed at the applicable rates and the amount reduced by 33-1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular employee who has been continuously employed at least six months and is the principal support of the household in which employee resides, or is the spouse of the principal support.

Date Filed: April 12, 2002 **Effective Date:**

Issued By: Donald R. Ball
Director of Regulatory Affairs **Case No.:**

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NDPSC Volume 7
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INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide interruptible sales or interruptible transportation service to customers is as follows:

1. Contribution

   (a) Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, service line(s), regulators, meters (excluding electronic measurement equipment), any required payments made by the Company to the transmission pipeline to accommodate the extensions, and other costs as adjusted for federal and state income taxes.

   (b) The contribution shall be made by:

      i. A one-time payment prior to construction or,

      ii. The customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the total contribution required prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for a five-year period commencing at the plant in service date, and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists for the subject project, the surety or guarantor shall pay the Company for such contribution requirement, or

      iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

   (c) Upon Completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

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INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

(d) Remote data acquisition equipment costs shall be subject to the terms and conditions specified in Transportation Service Rates 81 and 82.

2. Refund

(a) If within the five-year period from the extension(s) in service date, the total of the customer's contribution and actual margin paid to the Company equals or exceeds the total present value of the revenue requirement associated with the extension, Company shall refund the amount exceeding the revenue requirement on the following basis:

i. Annually, beginning at the 2nd anniversary of the extension(s) in service date, the Company will refund to the customer, the amount exceeding the total present value of the revenue requirement at a rate of 50% of the current year margin associated with the customer" actual throughput.

ii. Customers who have posted a bond, letter of credit, or a written guarantee commitment will be notified of any reduction in surety or guarantee requirements based on the above calculation.

iii. No refunds will be made for amounts less than $25.

(b) Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

(c) No refund shall be made by the Company after the five-year refund period has expired, and in no case shall the refund, excluding interest, exceed the amount of contribution made by the customer.

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FIRM GAS SERVICE EXTENSION POLICY Rate 120

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales service to customers is as follows:

(A) General Rules and Regulations Applicable to all Firm Service Extensions

1. An extension will be constructed without a contribution if the estimated capital expenditure is cost justified as defined in ¶A.3.

2. The Company may require customer or developer cost participation if the estimated capital expenditure is not cost justified.

3. The extension will be considered cost justified if the calculated maximum allowable investment equals or exceeds the estimated capital expenditure using the following formula:

   Maximum Allowable Investment =

Annual Basic Service Charge + (Project Estimated 3rd Year Annual Dk x Distribution Delivery Charge/LARR

where: LARR = Levelized Annual Revenue Requirement Factor of 19.954%

4. Cost of the extension shall include the gas main extension(s), valves, service line(s), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs excluding the distribution meter and regulator.

   The service line is that portion of the gas service extending from the gas main to the connection at the house regulator and/or meter.

5. Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer or the developer and Company.

6. A refund will be made only when there is a reduction in the amount of contribution required within a five-year period from the extension(s) in service date. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

   No refund shall be made by Company after the five-year refund period and in no case shall the refund excluding interest, exceed the amount of the contribution.

7. The Company reserves the right to charge customer the cost associated with providing service to customer if service is not initiated within 12 months of such installation.

(B) Customer Extensions

Cost participation for extensions where customers will be immediately available for service is as follows:

1. Contribution

   (a) When a contribution is required, the customer(s) shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with ¶ A.3.

   (b) The contribution shall be made by:

      i. A one-time payment prior to construction, or

      ii. Payment of 25% of the contribution prior to construction and the balance in no more than twenty-four equal monthly installments. If customer discontinues service within the twenty-four month period, the balance will be due and payable upon discontinuance of service, or

      iii. Customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized

iv. to do business in the state, letter of credit, or written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exits in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement, or

v. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

(c) Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

(d) If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment.

(e) The recalculated contribution requirement shall be collected from the new applicant(s).

2. Refund

(a) The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Customers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

(b) No refunds will be made until the new applicants begin taking service from the Company.

(c) If the addition of new customers will increase the contribution required from existing customer(s), the extension will be considered a new extension and treated separately.

3. Incremental Expansion Surcharge

(a) The Company, in its sole discretion, may offer an Incremental Expansion Surcharge (Surcharge) to a project consisting of 10 or more customers requesting service when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. If the Company and customers mutually agree that the project will be funded through a Surcharge, the project will be designated an expansion area and the Surcharge will be applicable to all connections within the expansion area. The contribution requirement to be collected under the Surcharge shall be the amount of the capital expenditure in excess of the Maximum Allowable Investment determined in accordance with ¶A.3.

i. A minimum up-front payment of $100.00 will be collected from each customer who signs an agreement to participate in the expansion.

ii. For projects that are expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus $1.50 per dk.

iii. For projects that are not expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus a commodity charge designed to provide recovery of the contribution requirement in a five-year period.

(b) The Surcharge shall remain in effect until the net present value of the contribution requirement, calculated using a discount rate equal to the overall rate of return authorized in the last rate case, is collected.

(c) The Surcharge shall apply to all customers connecting to natural gas service within the expansion area until the contribution requirement is satisfied.

(d) The net present value of the Surcharge will be treated as a contribution-in-aid of construction for accounting purposes.

(C) Developer Extensions

Cost participation may be required for extensions such as a subdivision or a mobile home court, in which a developer is installing roads, utilizes, etc., before housing is built.

1. Contribution

(a) When a contribution is required, the developer shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with ¶A.3.

(b) The contribution shall be made by:

i. A one-time payment prior to construction, or

ii. Developer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or a written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the subject project based on a recalculated maximum expenditure, the surety shall reimburse the Company for such recalculated contribution requirement, or

iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

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Gas Rate Schedule

FIRM GAS SERVICE EXTENSION POLICY Rate 120

(c) Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

2. Refund

(a) If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment. Such recalculation shall be done annually based upon the anniversary of the extension(s) in service date.

(b) The Company will refund to the developer the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Developers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guaranty requirements.

(c) If the addition of new customer(s) will increase the contribution required from the developer, the extension will be considered a new extension and treated separately.

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NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

A. The Company will install, at its expense, a service line extending from the main to the connection at the premise regulator and/or meter for all customers connected on and after (effective date of tariff) and all replacement service lines installed on and after (effective date of tariff). The service line installed by the Company will remain the Company's property.

B. A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation.

1. The portion of the service line not cost justified shall be charged to the customer on the basis of direct costs to the Company. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

2. Where service line location changes are made due to building encroachments (a building is being constructed or is already located over a service line, etc.), because the customer shall be charged for on the basis of direct costs incurred by the Company.

3. Whenever a service line is damaged by the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

4. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with ¶ B.2 above.

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Issued By:

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1st Revised Sheet No. 2

COMMUNITIES SERVED

NATURAL GAS SERVICE

~~**Rate Zone 1 and Rate Zone 2**~~
~~**(Customer-Owned Service Lines)**~~
~~**and (Company-Owned Service Lines)**~~
Dakota Heartland Region

C

Apple Valley	Devils Lake	Mandan	Steele
Barlow	Eldridge	Max	Surrey
Berthold	Fort Totten	Medina	Tappen
Bismarck*	Garrison	Minot*	Turtle Lake
Burlington	Glen Ullin	New Rockford	Underwood
Carrington	Grafton	New Salem	Valley City
Cavalier	Jamestown	Park River	Walhalla
Cleveland	Langdon	Riverdale	Washburn
Dawson	Lincoln	Sandborn	Wilton
Des Lacs	Linton	Sheyenne	

Badlands Region

Alexander	Golva	Ray	Taylor
Arnegard	Hebron	Regent	Tioga
Beach	Killdeer	Rhame	Trenton
Belfield	Lefor	Richardton	Watford City
Bowman	Lignite	Ross	Wheelock
Dickinson*	Marmarth	Sentinel Butte	White Earth
East Fairview	Mott	Springbrook	Williston*
Epping	New England	South Heart	
Gladstone	Palermo	Stanley	

PROPANE SERVICE

Badlands Region
Hettinger

*Designates Region Office

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Issued By:

Case No.:

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RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	PGA Items	Total Rate/ Dk
Residential Rate 60	4	$0.39 per day	$0.432	$2.907	$3.339
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$2.907	$3.045
Interruptible Service			$0.120	$1.922	$2.042
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.80 per day			
Meters rated > 500 cubic feet		$1.70 per day	$0.410	$2.907	$3.317
Small Interruptible Gas Rate 71	14	$100.00 per month	Per Contract	$1.653	Per Contract
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		$0.80 per day			
Meters rated > 500 cubic feet		$1.70 per day			
Winter Gas Usage			$0.410	$3.538	$3.948
Summer Gas Usage			$0.410	$2.416	$2.826
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.366		
Minimum			$0.102		
Fuel Charge				$0.018	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.018	
Large Interruptible Gas Rate 85	27	$675.00 per month	Per Contract	$1.653	Per Contract
Residential Propane Rate 90	32	$0.39 per day	$0.432	$2.882	$3.314
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		$0.80 per day			
Meters rated > 500 cubic feet		$1.70 per day	$0.410	$2.882	$3.292

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RATE SUMMARY SHEET

Miscellaneous Charges	Amount
Late Payment	1% per month
Returned Check	$20.00 per check
Minimum reconnection charge after termination for nonpayment or other causes -During normal business hours -After normal business hours	 $30.00 Current service labor rate per hour
Reconnection charge applicable to seasonal or temporary customers -During normal business hours -After normal business hours	Basic Service Charge applicable during the period while service was not being used. Minimum- $30.00 Minimum- Current service labor rate per hour
Reconnection charge applicable to transportation customers when remote data acquisition equipment must be reinstalled	$160.00

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RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$.39 per day	C
Distribution Delivery Charge:	$.432 per dk	
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

~~Base Rate Per Month:~~

~~Zones 1 and 2~~

~~For customers with meters rated under 500 cubic feet per hour $ 6.50~~
~~For customers with meters rated over 500 cubic feet per hour $13.00~~

~~Commodity Charge:~~

~~Zone 1~~

~~First 5 dk per month $4.681 per dk~~
~~Over 5 dk per month $4.230 per dk~~

~~Zone 2~~

~~First 5 dk per month $4.851 per dk~~
~~Next 10 dk per month $4.400 per dk~~
~~Over 15 dk per month $4.230 per dk~~ C

Minimum Bill:

Basic Service Charge.~~Base Rate~~ T

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

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Gas Rate Schedule

RESIDENTIAL GAS SERVICE Rate 60

Cost of Purchased Gas ~~Adjustment~~:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis. T

~~Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.~~ T

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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2nd Revised Sheet No. 5

OPTIONAL SEASONAL RESIDENTIAL GAS SERVICE Rate 62

~~Availability:~~

~~In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.~~

~~Rate:~~

~~Base Rate Per Month:~~

~~Zones 1 and 2~~

~~For customers with meters rated under 500 cubic feet per hour~~	~~$ 6.50~~
~~For customers with meters rated over 500 cubic feet per hour~~	~~$13.00~~

~~Commodity Charge:~~

~~Zone 1~~	~~Winter~~	~~Summer~~
~~First 5 dk per month~~	~~$4.795 per dk~~	~~$3.687 per dk~~
~~Over 5 dk per month~~	~~$4.344 per dk~~	~~$3.236 per dk~~

~~Zone 2~~	~~Winter~~	~~Summer~~
~~First 5 dk per month~~	~~$4.965 per dk~~	~~$3.857 per dk~~
~~Next 10 dk per month~~	~~$4.514 per dk~~	~~$3.406 per dk~~
~~Over 15 dk per month~~	~~$4.344 per dk~~	~~$3.236 per dk~~

~~Winter – Effective for bills rendered October 1 through May 31~~
~~Summer – Effective for bills rendered June 1 through September 30~~

~~Minimum Bill:~~

~~Base Rate~~

~~Payment:~~

~~Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.~~

~~Cost of Purchased Gas Adjustment:~~

~~Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.~~

D

D

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State of North Dakota
Gas Rate Schedule

OPTIONAL SEASONAL RESIDENTIAL GAS SERVICE Rate 62

~~**General Terms and Conditions:**~~ D

~~1.TERM – The customer agrees to contract for service under the Optional Seasonal Residential Gas Service Rate 62 for a minimum of one year.~~

~~2.RULES – The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.~~ D

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AIR FORCE Rate 64

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate: C

Basic Service Charge:	
Minot Air Force Base	$1,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$135.00 per month
Distribution Delivery Charge:	
Firm Service	$.138 per dk
Interruptible Service	$.120 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

~~Base Rate Per Meter:~~
~~Minot Air Force Base - $750.00 per month~~
~~Perimeter Acquisition Radar (PAR) Site - $35.00 per month~~

~~Minot Air Force Base:~~
~~Firm Sales~~
~~Commodity Charge — $1.932 per dk~~
~~Plus Applicable Pipeline Demand & Transportation Charges~~

~~Interruptible Sales~~
~~Commodity Charge — $1.885 per dk~~
~~Plus Applicable Pipeline Transportation Charges~~

~~PAR Site & Minot Air Force Base Pro Shop:~~
~~Firm Sales~~
~~Commodity Charge — $3.840 per dk~~ C

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Original Sheet No. 7.1

AIR FORCE Rate 64

~~Interruptible Transportation~~
~~Transportation Charge \$.124 per dk~~
~~Balancing Charge \$.342 per dk~~
~~Fuel Charge See Supplement Sheet~~ D

~~The terms and conditions of service applicable under Transportation Service Rates 81, 82, 84 shall also apply to services rendered under Air Force Rate 64.~~ D

Minimum Bill:

Basic Service Charge.~~Base Rate~~ T

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject tc a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas ~~Adjustment~~: T

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

~~Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.~~ T

General Terms and Conditions:

1. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If the customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm Service distribution delivery charge and cost of gas ~~firm sales commodity charge~~ rates set forth above, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or \$50.00~~\$10.00~~ per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company. C C

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State of North Dakota
Gas Rate Schedule

AIR FORCE Rate 64

2. CONTRACT – Terms of service other than the rate shall be specified in contracts between Minot Air Force Base, and PAR and the Company.

3. ~~RULES~~—The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state. T

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2nd Revised Sheet No. 13

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

Basic Service Charge:		C
For customers with meters rated under 500 cubic feet per hour	$.80 per day	
For customers with meters rated over 500 cubic feet per hour	$1.70 per day	
Distribution Delivery Charge:	$.410 per dk	
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	
~~Commodity Charge:~~		
~~Zone 1~~		
~~First 15 dk per month~~	~~$4.748 per dk~~	
~~Over 15 dk per month~~	~~$4.248 per dk~~	
~~Zone 2~~		
~~First 15 dk per month~~	~~$4.918 per dk~~	
~~Over 15 dk per month~~	~~$4.248 per dk~~	C

Minimum Bill:

Basic Service Charge.~~Base Rate~~ T

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Date Filed: **Effective Date:**

Issued By:

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FIRM GENERAL GAS SERVICE Rate 70

Cost of Purchased Gas: ~~Adjustment:~~

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis ~~Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.~~ T T

General Terms and Conditions:

~~RULES —~~The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state. T

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SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$100.00 per month		C
Distribution Delivery Charge:	Maximum $1.213 per dk	Minimum $.366 per dk	
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate		

~~Base Rate (Zones 1 and 2): $35.00 per month~~

~~Commodity Charge:~~	~~Maximum Rate~~	~~Minimum Rate~~
~~Zone 1~~	~~$3.500 per dk~~	~~$3.056 per dk~~
~~Zone 2~~		
~~First 15 dk per month~~	~~$3.670 per dk~~	~~$3.670 per dk~~
~~Over 15 dk per month~~	~~$3.500 per dk~~	~~$3.056 per dk~~

The Distribution Delivery Charge ~~commodity charge~~ shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the cost of Purchased Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above. C

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Issued By:

Case No.:

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State of North Dakota
Gas Rate Schedule

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Minimum Bill:

Basic Service Charge.~~Base Rate~~ | T

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas ~~Adjustment~~:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis. | T

~~Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.~~ | T

General Terms and Conditions:

1. PRIORITY OF SERVICE – Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the ~~tail block of the applicable~~ Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas) ~~commodity charge rate~~, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00~~10.00~~ per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company. | T | C

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SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS – Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS –Remote data acquisition ~~Electronic measurement~~ equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder. T

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and ~~a~~ acceptable telephone service available ~~tie to customer's telephone system accessible~~ at customer's meter location(s). T Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment. C C

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 6
2nd Revised Sheet No. 15

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:		C
For customers with meters rated under 500 cubic feet per hour	$.80 per day	
For customers with meters rated over 500 cubic feet per hour	$1.70 per day	
Distribution Delivery Charge:	$.410 per dk	
Cost of Gas:		
Winter- Bills rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate	
Summer- Bills rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate	

~~Base Rate Per Month:~~

~~Zones 1 and 2~~

~~For customers with meters rated under 500 cubic feet per hour~~	~~$ 8.50~~
~~For customers with meters rated over 500 cubic feet per hour~~	~~$17.00~~

~~Commodity Charge:~~

~~Zone 1~~	~~Winter~~	~~Summer~~
~~First 15 dk per month~~	~~$4.861 per dk~~	~~$3.753 per dk~~
~~Over 15 dk per month~~	~~$4.361 per dk~~	~~$3.253 per dk~~

~~Zone 2~~	~~Winter~~	~~Summer~~
~~First 15 dk per month~~	~~$5.031 per dk~~	~~$3.923 per dk~~
~~Over 15 dk per month~~	~~$4.361 per dk~~	~~$3.253 per dk~~

~~Winter – Effective for bills rendered October 1 through May 31~~
~~Summer – Effective for bills rendered June 1 through September 30~~ C

Date Filed: **Effective Date:**

Issued By:

Case No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 6
Original Sheet No. 15.1

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Minimum Bill:

Basic Service Charge.~~Base Rate~~ T

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas ~~Adjustment~~: T

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.~~Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.~~

General Terms and Conditions:

1. ~~TERM —~~The customer agrees to contract for service under the Optional Seasonal General Gas Service Rate 72 for a minimum of one year. T

2. ~~RULES —~~The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state. T

Date Filed: **Effective Date:**

Issued By:

Case No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

TRANSPORTATION SERVICE Rates 81 and 82

Availability:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through Company's distribution facilities. In order to obtain transportation service, customer must qualify under an applicable gas transportation service rate; meet the general terms and conditions of service provided hereunder; and enter into a gas transportation agreement upon request by the Company.

The transportation services are as follows:

Small Interruptible General Gas Transportation Service Rate 81:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point, whose average use of natural gas will not exceed 100,000 dk annually and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Small Interruptible General Gas Service Rate 71. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. ~~or Firm Gas Transportation Service Rate 84, whichever is applicable.~~ D

Large Interruptible General Gas Transportation Service Rate 82:
Transportation service is available for all general gas service customers whose interruptible natural gas load will ~~exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point, whose average use of natural gas will~~ exceed 100,000 dk annually metered at a single delivery point, and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Large Interruptible General Gas Service Rate 85. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70 ~~or Firm Gas Transportation Service Rate 84, whichever is applicable~~. T

~~Firm Gas Transportation Service Rate 84:~~

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Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

~~Firm transportation service is available for the firm requirements of those customers who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Small Interruptible General Gas Service Rate 71 or Large Interruptible General Gas Service Rate 85. Such firm requirements, subject to approval by the Company, must be set forth in a firm service agreement.~~ D

Rate:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge ~~Base Rate and Nomination Charge~~ plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71, ~~Rate 84~~ or Rate 85, the ~~base rate~~ Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived. C

Basic Service Charge: ~~Base Rate:~~ C

Rate 81 $150.00 ~~35.00~~ per month
Rate 82 $725.00~~450.00~~ per month
~~Rate 84 $ 35.00 per month for customers qualifying under Rate 81~~
~~$450.00 per month for customers qualifying under Rate 82~~

	Rate 81	Rate 82	~~Rate 84~~
Maximum Rate per dk	$0.366~~509~~	$0.298~~321~~	~~$0.983~~
Minimum Rate per dk	$0.102	$0.061	~~$0.983~~
Balancing Charge per dk	$0.300~~342~~	$0.300~~342~~	~~$0.342~~
~~Nomination Charge per month~~	~~$50.00~~	~~$50.00~~	~~$50.00~~

C

Fuel Charge:

Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See Rate Summary Sheet ~~supplemental sheet~~ for currently effective charge. T

General Terms and Conditions:

1. CRITERIA FOR SERVICE: In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service

provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

2. REQUEST FOR GAS TRANSPORTATION SERVICE:
   a. To qualify for gas transportation service a customer must request the service pursuant to the provisions set forth herein. The service shall be provided only to the extent that the Company's existing operating capacity permits.

   b. ~~If the Company determines that firm capacity exists, requests for firm gas transportation service shall be processed on a first come first serve basis~~. | D

   b. Requests for ~~interruptible~~ transportation service shall be considered in accordance with the provisions of Rate 100, §V.10. |

3. MULTIPLE SERVICES THROUGH ONE METER:
   a. In the event customer desires firm sales service in addition to gas transportation service, customer shall request such firm volume requirements, and upon approval by Company, such firm volume requirements shall be set forth in a firm service agreement. For billing purposes, the level of volumes so specified or the actual volume used, whichever is lower shall be billed at Rate 70 ~~or Rate 84, whichever is applicable~~. Volumes delivered in excess of such firm volumes shall be billed at the applicable gas transportation rate. Customer has the option to install at their expense, piping necessary for separate measurement of sales and transportation volumes. | D

   b. The customer shall pay, in addition to charges specified in the applicable gas transportation rate schedule, charges under all other applicable rate schedules for any service in addition to that provided herein (irrespective of whether the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE – Company shall have the right to curtail or interrupt deliveries without being required to give previous notice of intention to curtail or interrupt, whenever, in its judgment, it may be necessary to do so to

protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

5. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken above that received on customer's behalf, shall be billed at the ~~tail block of the applicable~~ Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas) ~~commodity charge rate~~, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 ~~10.00~~per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company. T C

6. NON-DELIVERED VOLUMES/PENALTY:
   a. In the event customer uses more gas than is being delivered to the Company's interconnection with the delivering pipeline(s) (receipt point), customer shall pay an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the same receipt point, any payment or overrun penalties the Company is required to make shall be allocated on a pro rata basis among such customers on the basis of each customer's use of gas in excess of available volumes. T

   b. In the event the customer's gas is not being delivered to the receipt point for any reason ~~due to shipper or pipeline constraints~~ and the customer continues to take gas, the customer shall be subject to ~~the rate charged to the customer shall be the tail block of the Firm General Gas Service Rate 70 commodity charge rate, plus~~ any applicable penalties or charges T

set forth in Paragraph 6.a. Gas volumes supplied by Company will be charged at Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas). The Company is under no obligation to notify customer of non-delivered volumes. T

c. In the event customer's transportation volumes are not available for any reason, customer may take interruptible sales service if such service is available. The availability of interruptible sales service shall be determined at the sole discretion of the Company.

7. ELECTION OF SERVICE – Prior to the initiation of service hereunder, the customer shall make an election of its requirements under each applicable rate schedule for the entire term of service. If mutually agreed to by Company and customer, the term of service may be amended. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under the appropriate sales rate schedule for the customer's operations.

   Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge as specified in Rate 100, §V.17.

8. BALANCING:
   a. To the extent practicable, customer and Company agree to the daily balancing of volumes of gas received and delivered on a thermal basis. Such balancing is subject to the customer's request and the Company's discretion to vary scheduled receipts and deliveries within existing Company operating limitations.

      If, at the end of a billing month, the accumulated difference between actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer exceeds 4% of that month's scheduled receipts, resulting in a negative imbalance (i.e., deliveries exceed scheduled receipts), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, the customer shall then be billed, in addition to the applicable transportation rate, a

penalty for the under nominated volume exceeding 4% at ~~the tail block of~~ the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas) ~~commodity charge rate~~. The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume on which a penalty was imposed. T

If, at the end of a billing month, the accumulated difference between nominated (scheduled) receipts on behalf of such customer and actual gas deliveries to the customer exceeds 4% of that month's scheduled receipts resulting in a positive imbalance (i.e., scheduled receipts exceed deliveries), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, (1) the Company may adjust the volume of gas received on behalf of the customer so as to eliminate the prior period over nomination exceeding 4% up to 10% and (2) the Company shall retain the over nomination of gas exceeding 10% free and clear of any adverse claims relating thereto when such accumulated difference exceeds 50 dk. The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume retained.

b. In the event customer's imbalance causes the Company to incur a balancing penalty from its interconnecting pipeline(s), customer shall pay any penalty payments or overrun charges the Company is required to make under the terms of its contract(s) with interconnecting pipeline(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the same interconnection with a delivering pipeline, any payment or overrun penalties the Company is required to make shall be apportioned among such customers on the basis of each customer's contribution toward the imbalance.

c. Customer's nomination made to clear imbalances will be subject to the priority of service and allocation of capacity provisions set forth in Rate 100, §V.10 and the penalties for failure to curtail or interrupt use of gas

set forth in Paragraph 5 of this rate schedule.

d. Termination of the gas transportation service shall not relieve Company and customer of the obligation to correct any quantity imbalances hereunder or customer of the obligation to pay money due hereunder to Company.

e. The Company may waive any penalty associated with Company adjustments to end-use customer nominations in those instances where the Company, due to operating limitations, is required to adjust end-use transportation customer nominations and such Company adjustments create a penalty situation, or preclude a customer from correcting an imbalance which results in a penalty.

9. NOMINATION VARIANCE CHARGE – The customer shall pay any payments the Company must make to its interconnecting pipeline(s), as a result of nomination variance penalties caused by customer's nomination variances. Such penalties will be allocated on the basis of each customer's contribution toward the nomination variance.

10. METERING REQUIREMENTS:

a. Remote data acquisition ~~Electronic measurement~~ equipment required by the Company for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by the customer. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. Company may remove such equipment when service hereunder is terminated. | T

b. The customer shall provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and acceptable ~~a~~ telephone service available ~~tie to customer's telephone system accessible~~ at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality | T

telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment. C C

11. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper or agent shall advise Company's gas nominations center, by 11:30 a.m. Central Clock Time, of the dk requirements customer has requested to be delivered at each delivery point the following day. Customer's daily nomination shall be its best estimate of the expected utilization for the gas day. Unless other arrangements are made, customer will be required to nominate for the non-business days involved prior to weekends and holidays.

    b. All nominations should include shipper and/or agent defined begin and end dates. Shippers and/or agents may nominate for periods longer than 1 day, provided the nomination begin and end dates are within the term of the service agreement.

    c. The Company has the sole right to refuse receipt of any volumes which exceed the maximum daily contract quantity and at no time shall the Company be required to accept quantities of gas for a customer in excess of the quantities of gas to be delivered to customer. If total nominated receipts exceed total deliveries at receipt points where more than one customer is receiving service, nominations will be allocated on a pro rata basis.

d. At no time shall Company have the responsibility to deliver gas in excess of customer's nomination.

e. In the event that more than one customer is receiving gas from the same shipper and/or agent at the same receipt point, any reduction in nominated volumes will be allocated on a pro rata basis, unless Company and shipper(s) and/or agent(s) have agreed to a predetermined allocation procedure. | T | T

12. WARRANTY – The customer, customer's agent, or customer's shipper warrants that it will have title to all gas it tenders or causes to be tendered to the Company, and such gas shall be free and clear of all liens and adverse claims and the customer, customer's agent, or customer's shipper shall indemnify the Company against all damages, costs, and expenses of any nature whatsoever arising from every claim against said gas.

13. FACILITY EXTENSIONS - If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities required to furnish firm gas service, the customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. Company may remove such facilities when service hereunder is terminated.

14. PAYMENT – Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

15. BILLING ERROR – In the event an error is discovered in any bill that the Company renders to customer, such error shall be adjusted within a period not to exceed 6 months from the date the billing error is first discovered.

16. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for service hereunder.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

TRANSPORTATION SERVICE Rates 81 and 82

17. ~~RULES~~ —The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state. | T

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 6
Original Sheet No. 27

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will ~~exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will~~ exceed 100,000 dk annually as metered at a single delivery point. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement. T

This rate schedule shall not apply for service to U.S. Government installations, which are covered by separate special contracts.

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate: C

Basic Service Charge	$675.00 per month	
Distribution Delivery Charge	Maximum $1.003 per dk	Minimum $.298 per dk
Cost of Gas	Determined Monthly- See Rate Summary Sheet for Current Rate	

~~(Zones 1 and 2)~~

~~Base Rate: $450.00 per month~~

~~Commodity Charge:~~

~~Maximum Rate $3.290 per dk~~
~~Minimum Rate $2.869 per dk~~

~~The commodity charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the cost of Purchased Gas Adjustment, shall apply for the term of the agreement regardless of a change in the rates set forth above.~~ C

Date Filed: **Effective Date:**

Issued By:

Case No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Minimum Bill:

Basic Service Charge.~~Base Rate~~ | T

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas ~~Adjustment~~:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.~~Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.~~ | T | T

General Terms and Conditions:

1. PRIORITY OF SERVICE – Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the ~~tail block of the applicable~~ Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas)~~ commodity charge rate~~, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00~~10.00~~ per dk of gas used in excess of the volume of gas to which customer was requested to curtail or | T | C

interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 90 days prior to the end of the initial term. Absent execution of such termination notice, the agreement shall continue for additional terms of equal length until written notice is given as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS –Remote data acquisition ~~Electronic measurement~~ equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder. T

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and acceptable~~a~~ telephone service available~~tie to customer's telephone system accessible~~ at customer's meter location(s). T Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment. C C

6. ~~RULES -~~The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 6
4th Revised Sheet No. 30

PURCHASED GAS COST ADJUSTMENT Rate 88

1. **Applicability:**
This rate schedule constitutes a purchased gas cost adjustment (PGA) provision and specifies the procedure to be utilized to adjust the rates for gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of gas supply, (b) amortization of the Unrecovered Purchased Gas Cost Account and (c) market based pricing differential.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the PGA shall be bills rendered on and after the first date of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file a PGA~~an adjustment~~ to reflect changes in its average cost of gas supply only when the amount of change in such PGA~~adjustment~~ is at least 10 (ten) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change. | T

3. **Purchased Gas Cost: ~~Adjustment:~~** | T
(a) The monthly PGA shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent PGA ~~general rate case~~. The cost of gas supply shall be the sum of all costs incurred in obtaining gas for general system supply. General system supply is defined as gas available for use by all customers served under retail sales rate schedules. The cost of gas supply shall include, but not be limited to, all demand, commodity, storage, gathering, and transportation charges incurred by Montana-Dakota for such gas supply, the overall rate of return on prepaid demand and commodity charges and gas storage balances required to maintain the system gas supply and hedging program gains, losses and transaction costs related to system gas supply. ~~Authority for inclusion of hedging program gains, losses and transaction costs expires on March 1, 1999 unless otherwise ordered by the Commission. Montana-Dakota shall submit, with each filing under this tariff, a complete report of hedging program activity.~~ | T | D | D

Date Filed: **Effective Date:**

Issued By:

Case No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

PURCHASED GAS COST ADJUSTMENT Rate 88

3. Purchased Gas Cost Adjustment (Cont.):
   (b) The PGA shall be computed as follows:

   (1) Demand costs shall include all annual gathering, transportation and storage demand charges at current rates.

   (2) Commodity costs shall include all annual gathering, transportation and storage charges at current rates.

   (3) The gas commodity cost shall reflect all commodity related gas costs estimated to be in effect for the month the PGA will be in effect and annual dk requirements.

   (4) The return on prepaid demand and commodity balances and storage balances shall be computed on an annual basis at the overall rate of return on rate base.

   The cost per dk for the month is the sum of the above divided by annual, weather normalized dk deliveries adjusted to reflect losses.

   (c) Monthly gas costs shall be calculated as follows:

   (1) Demand costs for firm customers shall be apportioned to all state jurisdictions served by Montana-Dakota on the basis of the overall ratio of each state's Maximum Daily Delivery Quantity (MDDQ).

   (2) Demand costs for interruptible sales customers shall be stated on a 100% load factor basis.

   (3) All commodity costs and other costs associated with the acquisition of gas for general system supply shall be apportioned to each state on the basis of total dks sold in each state, regardless of the actual points of delivery of such gas.

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State of North Dakota
Gas Rate Schedule

PURCHASED GAS COST ADJUSTMENT Rate 88

3. Purchased Gas Cost Adjustment (Cont.)
   (4) The return requirement related to prepaid demand and commodity charges and gas storage balances shall be included on a per dk basis. The prepaid demand and storage balances shall be apportioned to all states on the basis of each state's MDDQ. The prepaid commodity charges shall be apportioned to all states on the basis of annual dks sold in each state. The unit cost shall be calculated using a thirteen-month average balance and the currently authorized return on rate base.

   (5) All costs related to specific end-use transactions shall not be included in the cost of gas supply determination but shall be directly billed to the customer(s) contracting for such service.

   (d) The PGA shall be applied to each of Montana-Dakota's rate schedules recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. **Surcharge Adjustment:**
   (a) All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on May 1 of each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Gas Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

5. **Unrecovered Purchased Gas Account:**
   (a) Items to be included in the Unrecovered Purchased Gas Cost Account, as calculated in accordance with Subsection 5(b) are:

   (1) Charges for gas supply which Montana-Dakota is unable to reflect in a Purchased Gas Cost Adjustment by reason of the tenone ~~tenth of one~~-cent minimum limitation set forth in Subsection 2(b). | T

   (2) Amounts of increased/decreased charges for gas supplies, which were paid during any period after the effective date of the most recent general rate case, but not yet included in sales rates.

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5. Unrecovered Purchased Gas Cost Account (Cont.):
   (3) Refunds received from supplier(s) with respect to gas supply. Such refunds received shall be credited to the Unrecovered Purchased Gas Cost Account.

   (4) Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

   (5) Demand costs recovered from the interruptible sales customers will be credited to the residential and firm general service customers.

   (b)

   (1) The amount to be included in the Unrecovered Purchased Gas Cost Account in order to reflect the items specified in Subsections 5(a)(1), (2), and (3) shall be calculated as follows:

      (i) Montana-Dakota shall first determine each month the unit cost for that month's natural gas supply as adjusted to levelize demand charges.

      Such adjustment to levelize supplier(s) demand charges shall be calculated as follows:

      The supplier's annual (calendar or fiscal) demand charges, which are payable in equal monthly payments shall be accumulated in a prepaid account (FERC Account 165). Each month a portion of such accumulated prepaid amount shall be amortized to cost of natural gas purchased (FERC Account 804). Such monthly amortization shall be based on a rate calculated by dividing the annual supplier(s) demand charges by projected annual natural gas sales units (calendar or fiscal, as appropriate). The resulting product shall then be multiplied by the projected natural gas unit sales for the current month. Such amount shall constitute the monthly amortization of prepaid supplier(s) demand charges to cost of natural gas supply.

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PURCHASED GAS COST ADJUSTMENT Rate 88

5. Unrecovered Purchased Gas Cost Account (Cont.):

(1)

(ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for gas supply which is reflected in the currently effective PGA. ~~(the cost of gas supply approved in the most recent rate case plus the Purchased Gas Cost Adjustment as calculated in Subsection 3(a).~~ T

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Gas Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Gas Cost Account, Account 191, at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The amount to be included in Account 191 for carrying charges shall be determined as follows:

Each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge; which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Unrecovered Purchased Gas Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

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PURCHASED GAS COST ADJUSTMENT Rate 88

5. Unrecovered Purchased Gas Cost Account (Cont.):
   (b) Reduction of Amounts in the Unrecovered Purchased Gas Cost Account:

   (1) The amounts in the Unrecovered Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

   (2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Gas Cost Account specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Unrecovered Purchased Gas Cost Account specified in Subsection 5(a)(4).

6. **Market-Based Pricing Differential:**
   (a) At the time of each surcharge adjustment, the Company will compute a credit to residential and firm general service rates based on 50% of all distribution delivery charge ~~non-gas commodity~~ revenues received from small interruptible sales and large interruptible sales customers in excess of the authorized minimum distribution delivery charge ~~non-gas commodity~~ rate approved in the most recent general rate case. | T | T

   (b) The unit adjustment shall be determined by dividing the balance resulting under Subsection 6(a) by the residential and firm general service sales volumes estimated to be sold during the 12 months following the effective date of each adjustment.

7. **Time and Manner of Filing:**
   (a) Montana-Dakota shall file each PGA~~adjustment~~ at least 20 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised PGA sheets identifying the amounts of the adjustments and the resulting currently effective PGA rates. | T

   (b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant pipeline tariff sheets supporting costs claimed.

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RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$.39 per day	C
Distribution Delivery Charge:	$.432 per dk	
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate	

~~Base Rate Per Month:~~

~~For customers with meters rated under 500 cubic feet per hour $ 6.50~~
~~For customers with meters rated over 500 cubic feet per hour $13.00~~

~~Commodity Charge:~~

~~First 5 dk per month $5.569~~
~~Next 10 dk per month $5.118~~
~~Over 15 dk per month $4.948~~ C

Minimum Bill:

Basic Service Charge.~~Base Rate~~ T

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:~~ Cost: Adjustment:~~

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.~~Bills are subject to an adjustment for cost of purchased propane as provided in Rate 99 or any amendments or alterations thereto.~~ T T

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RESIDENTIAL PROPANE SERVICE Rate 90

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge: C

For customers with meters rated under 500 cubic feet per hour — $.80 per day

For customers with meters rated over 500 cubic feet per hour — $1.70 per day

Distribution Delivery Charge: $.410 per dk

Cost of Propane: Determined Monthly- See Rate Summary Sheet for Current Rate

~~Base Rate Per Month:~~

~~For customers with meters rated under 500 cubic feet per hour — $ 8.50~~
~~For customers with meters rated over 500 cubic feet per hour — $17.00~~

~~Commodity Charge:~~

~~First 5 dk per month — $5.636~~
~~Over 15 dk per month — $4.966~~ C

Minimum Bill:

Basic Service Charge. ~~Base Rate~~ T

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane: ~~Cost Adjustment~~: T

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.~~Bills are subject to an adjustment for cost~~ T

Date Filed: **Effective Date:**

Issued By:

Case No.:

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FIRM GENERAL PROPANE SERVICE Rate 92

~~of purchased propane as provided in Rate 99 or any amendments or alterations thereto.~~ T

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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PURCHASED PROPANE COST ADJUSTMENT Rate 99

1. **Availability:**
This rate schedule constitutes a purchased propane cost adjustment (PCA) provision and specifies the procedure to be utilized to adjust the rates for propane gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of propane supply and (b) amortization of the Unrecovered Purchased Propane Cost Account.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the PCA shall be bills rendered on and after the first day of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file a PCA ~~an adjustment~~ to reflect changes in its average cost of propane supply only when the amount of such change in PCA~~adjustment~~ is at least 10 (ten) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change. | T

3. **Purchased Propane Cost ~~Adjustment~~:** | T
(a) The monthly PCA shall reflect changes in Montana-Dakota's cost of propane supply as compared to the cost of propane supply approved in its most recent PCA ~~retail sales rates~~. The cost of propane supply shall include, but not be limited to, all commodity and transportation charges incurred by Montana-Dakota for such propane supply. | T

(b) The propane commodity cost shall reflect all commodity related propane costs estimated to be incurred for the month the PCA will be in effect and estimated dk purchases.

The unit cost per dk for the month shall be the commodity costs divided by estimated dk purchases for the month.

4. **Surcharge Adjustment:**
All propane sales schedules shall be subject to a Surcharge Adjustment to be effective on May 1 each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Propane Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

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PURCHASED PROPANE COST ADJUSTMENT Rate 99

5. Unrecovered Purchased Propane Cost Account:

(a) Items to be included in the Unrecovered Purchased Propane Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for propane supply which Montana-Dakota is unable to reflect in a Purchased Propane Cost Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for propane supplies that were paid during any period after the effective date of the most recent approved rates, but not yet included in propane sales rates.

(3) Carrying charges or credits.

(b)

(1) The amount to be included in the Unrecovered Purchased Propane Cost Account in order to reflect the items specified in Subsections 5(a)(1) and (2) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's propane supply.

(ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for propane supply, which is reflected in the currently effective PCA.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each propane rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Propane Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Propane Cost Account, Account 191, as follows:

Each month, Account 191 shall be debited (on a debit balance) or credited (on a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance on Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The carrying charges shall be accrued in a supplementary Unrecovered Purchased Propane Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in the Unrecovered Purchased Propane Cost Account:

(1) The amounts in the Unrecovered Purchased Propane Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Propane Cost Account specified in Subsections 5(a)(1) and (2) and the amounts in the supplementary Unrecovered Purchased Propane Cost Account specified in Subsection 5(b)(2)(ii).

6. Time and Manner of Filing:

(a) Montana-Dakota shall file each PCA~~adjustment~~ at least 10 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised PCA sheets identifying the amounts of the adjustments and the resulting currently effective PCA rates. | T

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant material supporting costs claimed.

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Date Filed: **Effective Date:**

Issued By:

Case No.:

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I. **PURPOSE:**

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Service Commission of North Dakota and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. **DEFINITIONS:**

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

AGENT – The party authorized by the transportation service customer to act on that customer's behalf. | T

APPLICANT – A customer requesting Company to provide service.

COMMISSION – Public Service Commission of the State of North Dakota.

COMPANY – Montana-Dakota Utilities Co.

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT – A reduction of transportation or retail natural gas service deemed necessary by the Company. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

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CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by Company at one location and at one point of delivery unless otherwise expressly in these rules or in a rate schedule.

DELIVERY POINT – The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on customer's premises.

GAS DAY – Means a period of twenty-four consecutive hours, beginning and ending at 9:00 a.m. Central Clock Time.

INTERRUPTION – A cessation of transportation or retail natural gas service deemed necessary by Company.

NOMINATION – The daily dk volume of natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

PIPELINE – The transmission company(s) delivering natural gas into company's system.

RATE – Shall mean and include every compensation, charge, fare, toll, rental and classification, or any of them, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT – The intertie between Company and the interconnecting pipeline(s) at which point Company assumes custody of the gas being transported.

SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.

III. **CUSTOMER OBLIGATION:**

1. APPLICATION FOR SERVICE – A customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. The Company may refuse a customer or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses gas service in the absence of application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

   Any customer may be required to make a deposit as required.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at Company's sole discretion, Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will ensure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

3. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises at all

reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

4. COMPANY PROPERTY – The customers shall exercise reasonable diligence in protecting the Company's property on their premises, and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

5. INTERFERENCE WITH COMPANY PROPERTY – The customer shall not disconnect, change connections, make connections or otherwise interfere with Company's meters or other property or permit same to be done by other than the Company's authorized employees.

6. RELOCATED LINES - Where Company facilities are located on a public or private utility easement and there is a building encroachment(s), over gas facilities (Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements. N N

7. NOTIFICATION OF LEAKS – The customer shall immediately notify the Company at its office of any escape of gas in or about the customer's premises.

8. TERMINATION OF SERVICE – All customers are required to notify the Company, to prevent their liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

9. REPORTING REQUIREMENTS – Customer shall furnish Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

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IV. **LIABILITY**

1. CONTINUITY OF SERVICE – The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

2. CUSTOMER'S EQUIPMENT – Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer or leased by the customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE – The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE – In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor

shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorization from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

V. **GENERAL TERMS AND CONDITIONS:**

1. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for any service.

2. RATE OPTIONS – Where more than one rate schedule is available for the same class of service, the Company will assist the customer in selecting the

2. RATE OPTIONS: (Cont.)
applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in twelve months unless there is a material change in the customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

3. RULES FOR APPLICATION OF GAS SERVICE:
(a) Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, may be served on the residential rate.

(b) Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty parlors, master metered apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site (this is not an all-inclusive list).

(c) The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

(d) If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for nonresidential purposes as defined herein), the customer will be billed

under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by Company to facilitate transportation service. Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Homes Construction and Safety Standards) Subpart G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities. ~~Contact your local Montana-Dakota Utilities Co. office for this information.~~ D

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission rules.

   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (b) The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to

the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided prompt payment record has been established.

7. METERING AND MEASUREMENT:
   (a) Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. Company will test meters in accordance with applicable state utility rules and regulations.

   (b) Transportation customers agree to provide the cost of the installation of electronic measurement equipment to Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the

application of a thermal factor to the volumes metered. This thermal factor consists of:

(a) An altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

(b) A Btu adjustment factor used to reflect the heating value of the gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT – The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and at a temperature base of sixty degrees Fahrenheit (60°F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AAGA-3/NX-19, as amended, supercompressibility calculation. For handbilled accounts, application of supercompressibility factors will be waived on monthly-billed volumes of 250 dk or less. | T | T

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from Highest to Lowest:
    (a) Priority 1 – Firm sales ~~and firm transportation~~ services. | D
    (b) Priority 2 – Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
    (c) Priority 3 – Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.

(d) Priority 4 – Small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
(e) Priority 5 – Large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
(f) Priority 6 – Gas scheduled to clear imbalances.

Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE – A charge of $20.00~~$10.00~~ will be collected by the Company for each check charged back to the Company by a bank. | C

13. TAX CLAUSE – In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any sales,

use or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

The charges to be added to the customer's service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

14. UTILITY CUSTOMER SERVICES:
    (a) The following services will be performed at no charge regardless of the time of performance:

        (1) Fire and explosions calls.

        (2) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

        (3) Maintenance or repair of Company-owned facilities on the customer's premises.

    (b) The following service calls will be performed at no charge during the Company's normal business hours:

        (1) Cut-ins and cut-outs.

        (2) Disconnecting of gas appliances permanently removed from service or in connection with cut-outs.

        (3) Lighting pilots, inspecting, and adjusting gas equipment in connection with establishing service when working cut-in orders.

        (4) Initial burner adjustment on residential gas burning appliances.

        (5) High bills or inadequate service complaints.

(6) Location of underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

(7) Pilot relighting, testing thermocouple for proper operation and any pilot cleaning that can be done without removing pilot assembly.

(8) Service calls for routine cut-ins, when the order is received prior to 12:00~~3:30~~ p.m. on a regular work day, requiring service on the date the order is received, will be considered as non-chargeable regardless if work is performed outside of normal working hours. | C

15. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and materials at retail prices.

    Customers requesting service after the Company's normal business hours will be informed of the after hour service rate and encouraged to have the service performed during normal business hours.

16. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service disconnected shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

17. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER –A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged the Basic Service Charge applicable during the period while service was not being used or a minimum | C

of $30.00. The minimum will be based on standard overtime rates for reconnection of service after normal business hours.~~fee of $18.00 will be collected for reconnecting gas sales or transportation service, during normal business hours, to any customer who has discontinued the same service at the same location during the preceding 12 month period. Standard overtime rates will apply after normal business hours.~~ C

Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the required electronic measurement equipment is necessary.

18. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $30.00~~12.00~~ before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours. C

19. DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS – The Company reserves the right to discontinue service for any of the following reasons:

    (a) In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    (b) In the event of tampering with the equipment furnished and owned by the Company

(c) For violation of or noncompliance with the Company's rules on file with the Commission.

(d) For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

(e) For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying Company facilities.

The Company may collect a reconnect fee of $30.00~~12.00~~ before restoring gas service, which has been disconnected for the above causes. | C

20. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with a Company meter, pressure regulator, registration, connections, equipment, seals, procedures or records that result in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.

(a) Examples of unauthorized use of service include the following, but are not limited to:

(1) Bypass piping around meter.
(2) Bypass piping installed in place of meter.
(3) Meter reversed.
(4) Meter index disengaged or removed.
(5) Service or equipment tampered with or piping connected ahead of meter.
(6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
(7) Gas being used after service has been discontinued by the Company.
(8) Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

(b) In the Event that there has been unauthorized use of service, customer shall be charged for:

(1) Time, material and transportation costs used in investigation.
(2) Estimated charge for non-metered gas.
(3) On-premise time to correct situation.
(4) Any damage to Company property.

(c) Customer service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid all charges as hereinafter set forth in this procedure.

(1) All delinquent bills, if any.
(2) The amount of any Company revenue loss attributable to said tampering.
(3) Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in number 20.b above.
(4) Reconnection fee applicable.

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(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

21. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
Rate 102 – Residential Rate for Regular Employees
Rate 119 – Interruptible Gas Service Extension Policy
Rate 120 – Firm Gas Service Extension Policy
Rate 124 – Service Lines

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RESIDENTIAL GAS SERVICE FOR REGULAR EMPLOYEES
Rate 102

The bill~~rate~~ for residential gas service for regular employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly owned subsidiaries of MDU Resources Group, Inc., shall be computed at the applicable rates and the amount reduced by 33-1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular employee who has been continuously employed at least six months and is the principal support of the household in which employee resides, or is the spouse of the principal support. | T | T

Date Filed: **Effective Date:**

Issued By:

Case No.:

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INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide interruptible sales or interruptible transportation service to customers is as follows:

1. Contribution

   (a) Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, ~~service stub(s),~~ service line(s) ~~complete where applicable~~, regulators, meters (excluding electronic measurement equipment), any required payments made by the Company to the transmission pipeline to accommodate the extensions, and other costs as adjusted for federal and state income taxes. | C

   (b) The contribution shall be made by:

      i. A one-time payment prior to construction or,

      ii. The customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the total contribution required prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for a five-year period commencing at the plant in service date, and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists for the subject project, the surety or guarantor shall pay the Company for such contribution requirement, or

      iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

   (c) Upon Completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

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INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

(d) Remote data acquisition ~~Electronic measurement~~ equipment costs shall be subject to the terms and conditions specified in Transportation Service Rates 81 and 82. | T

2. Refund

(a) If within the five-year period from the extension(s) in service date, the total of the customer's contribution and actual margin paid to the Company equals or exceeds the total present value of the revenue requirement associated with the extension, Company shall refund the amount exceeding the revenue requirement on the following basis:

i. Annually, beginning at the 2nd anniversary of the extension(s) in service date, the Company will refund to the customer, the amount exceeding the total present value of the revenue requirement at a rate of 50% of the current year margin associated with the customer" actual throughput.

ii. Customers who have posted a bond, letter of credit, or a written guarantee commitment will be notified of any reduction in surety or guarantee requirements based on the above calculation.

iii. No refunds will be made for amounts less than $25.

(b) Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

(c) No refund shall be made by the Company after the five-year refund period has expired, and in no case shall the refund, excluding interest, exceed the amount of contribution made by the customer.

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FIRM GAS SERVICE EXTENSION POLICY Rate 120

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales ~~or firm transportation~~ service to customers is as follows: | D

(A) General Rules and Regulations Applicable to all Firm Service Extensions

1. An extension will be constructed without a contribution if the estimated capital expenditure is cost justified as defined in ¶A.3.

2. The Company may require customer or developer cost participation if the estimated capital expenditure is not cost justified.

3. The extension will be considered cost justified if the calculated maximum allowable investment equals or exceeds the estimated capital expenditure using the following formula:

   Maximum Allowable Investment =

   Annual Basic Service Charge ~~Base Rate~~ + (Project Estimated 3rd Year Annual Dk x Distribution Delivery Charge~~Unit Margin~~)/LARR | T
   ~~LARR + O&M~~

   where: LARR = Levelized Annual Revenue Requirement Factor of 19.954%
   ~~O&M = Operating and Maintenance Factor of 3.870%~~ |

4. Cost of the extension shall include the gas main extension(s), valves, ~~service stub(s), or~~ service line(s)~~complete where applicable~~, any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs excluding the distribution meter and regulator. | C

   ~~The service stub is that portion of the gas service extending from the main to the private property line or easement boundary.~~ | D

   The service line is that portion of the gas service extending from the gas main to the connection at the house regulator and/or meter. ~~for those customers served in the communities set forth in Rate Zone 2.~~ | D

   ~~The service line is that portion of the gas service extending from the service stub to the connection at the house regulator and/or meter. Service lines are installed at~~ | D

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FIRM GAS SERVICE EXTENSION POLICY Rate 120

5. ~~customer's expense and are owned by and shall be maintained at customer's expense~~

(A) General Rules & Regulations Applicable to all Firm Service Extensions (Cont.)

5. Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer or the developer and Company.

6. A refund will be made only when there is a reduction in the amount of contribution required within a five-year period from the extension(s) in service date. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

   No refund shall be made by Company after the five-year refund period and in no case shall the refund excluding interest, exceed the amount of the contribution.

7. The Company reserves the right to charge customer the cost associated with providing service to customer if service is not initiated within 12 months of such installation. N

(B) Customer Extensions

Cost participation for extensions where customers will be immediately available for service is as follows:

1. Contribution

   (a) When a contribution is required, the customer(s) shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with ¶ A.3.

   (b) The contribution shall be made by:

      i. A one-time payment prior to construction, or

      ii. Payment of 25% of the contribution prior to construction and the balance in no more than twenty-four equal monthly installments. If

customer discontinues service within the twenty-four month period, the balance will be due and payable upon discontinuance of service, or

iii. Customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exits in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement, or

iv. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

(c) Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

(d) If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment.

(e) The recalculated contribution requirement shall be collected from the new applicant(s).

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2. Refund

(a) The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Customers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

(b) No refunds will be made until the new applicants begin taking service from the Company.

(c) If the addition of new customers will increase the contribution required from existing customer(s), the extension will be considered a new extension and treated separately.

3. Incremental Expansion Surcharge

(a) The Company, in its sole discretion, may offer an Incremental Expansion Surcharge (Surcharge) to a project consisting of 10 or more customers requesting service when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. If the Company and customers mutually agree that the project will be funded through a Surcharge, the project will be designated an expansion area and the Surcharge will be applicable to all connections within the expansion area. The contribution requirement to be collected under the Surcharge shall be the amount of the capital expenditure in excess of the Maximum Allowable Investment determined in accordance with ¶A.3.

i. A minimum up-front payment of $100.00 will be collected from each customer who signs an agreement to participate in the expansion.

ii. For projects that are expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus $1.50 per dk.

iii. For projects that are not expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus a commodity charge designed to provide recovery of the contribution requirement in a five-year period.

(b) The Surcharge shall remain in effect until the net present value of the contribution requirement, calculated using a discount rate equal to the overall rate of return authorized in the last rate case, is collected.

(c) The Surcharge shall apply to all customers connecting to natural gas service within the expansion area until the contribution requirement is satisfied.

(d) The net present value of the Surcharge will be treated as a contribution-in-aid of construction for accounting purposes.

(C) Developer Extensions

Cost participation may be required for extensions such as a subdivision or a mobile home court, in which a developer is installing roads, utilizes, etc., before housing is built.

1. Contribution

(a) When a contribution is required, the developer shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with ¶A.3.

(b) The contribution shall be made by:

i. A one-time payment prior to construction, or

ii. Developer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or a written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the

subject project based on a recalculated maximum expenditure, the surety shall reimburse the Company for such recalculated contribution requirement, or

iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

(c) Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

2. Refund

(a) If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment. Such recalculation shall be done annually based upon the anniversary of the extension(s) in service date.

(b) The Company will refund to the developer the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Developers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guaranty requirements.

(c) If the addition of new customer(s) will increase the contribution required from the developer, the extension will be considered a new extension and treated separately.

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NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

A. ~~NEW INSTALLATION OF COMPANY-OWNED SERVICE LINES—~~The Company will install, at its expense, a service line extending ~~up to 150 feet~~ from the main to the connection at the premise ~~house~~ regulator and/or meter for all~~those~~ customers connected on and after (effective date of tariff) and all replacement service lines installed on and after (effective date of tariff). The service line installed by the Company will remain the Company's property.~~served in the communities set forth in Rate Zone 2. A contribution may be required for that portion of the service line exceeding 150 feet in accordance with the Firm Gas Service Extension Policy Rate. 120~~ N

B. ~~The following will apply to all new customer-owned gas service lines, and to the replacement, relocation and repair of all gas service lines on private property.~~A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation. N N

1. The portion of the ~~customer shall be charged for a new~~ service line not cost justified shall be charged to the customer on the basis of direct costs to the Company ~~including material, labor, transportation, etc. Such costs shall include ordinary payroll and general overhead loadings~~. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply. N

2. ~~If the customer's service line is less than 25 years old, and is coated steel or plastic pipe, such line shall be pressure tested in accordance with the Company's rules for pressure testing. If the service line is found to be leaking due to faulty installation or due to a lack of cathodic protection, has damaged coating, surface pitting, etc., the line will be repaired or replaced at no cost to the customer. All other repairs shall be at customer's expense~~. D D

Date Filed: **Effective Date:**

Issued By:

Case No.:

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Gas Rate Schedule

NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

~~3.For coated steel or plastic pipe service lines more than 25 years old which need to be repaired and/or replaced and for bare pipe service lines of any age, the customer shall be charged in accordance with B.1. above.~~ D

~~In accordance with Company Standards, service line replacement will be constructed with outside risers and meters. Such reconstruction will nearly always involve minor changes in inside piping. The inside piping changes may be incorporated into the total footage to be billed as provided in B.1. above~~.

~~4.Where the customer's gas service line must be replaced because the mains are being relocated (alley to street or street to alley), such line change or relocation will be made at the Company's expense if the service line is coated steel or plastic pipe and is less than 25 years old. If the line is older and passes the required pressure test, the replacement will be made at the Company's expense. If such older line does not pass the required pressure test, the line shall be replaced at the customer's expense except that the customer shall be charged only for the lesser of: (a) the equivalent length of the old service line or (b) the actual length of the new service line if it is shorter than the older service line being replaced. The basis for billing the customer shall be as outlined in B.1. above.~~

~~5.The customer has the option of waiving the pressure test and receiving a credit equal to the cost of the pressure test against the installed cost of a new sevice line.~~ D

2~~6~~.Where service line location changes are necessary made due to building encroachments (a building is being constructed or is already located over a service line, etc.), ~~or due to the necessity to increase the size and capacity of an existing service line~~ because ~~of increased demand,~~ the customer shall be charged for on the basis of direct costs incurred by the Company.~~, as outlined in B.1. above~~.

3~~7~~.Whenever a service line is damaged by ~~excavating and/or earth-moving equipment, etc., and is either~~ the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged on a direct cost basis ~~including ordinary payroll and general overhead loadings~~. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor. ~~Damages done by the customer or someone working directly for him~~ M

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

~~shall be paid for by the customer. Such charges shall be made regardless of the age of the damaged service line.~~

~~3.~~4. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with ¶ B.2 above. N

PU-399-02-183

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 5 13 02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Transfer from service label)* 7001 2510 0005 8654 8730

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

PU-399-02-183

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

PM JUN

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* [signature] B. Date of Delivery 6-7-02

C. Signature
X [signature] ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* 7001 1940 0005 3426 8772

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

Public Service Commission
State of North Dakota

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Original Transcript of Hearing - October 7, 2002
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10/23/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

CASE NO.
PU-399-02-183

TRANSCRIPT OF HEARING

State Capitol
Commission Hearing Room
Bismarck, North Dakota
October 7, 2002

Before Allen C. Hoberg
Hearing Officer

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APPEARANCES

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Bismarck, North Dakota 58505-0480

FOR THE COMMISSION.

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FOR MONTANA-DAKOTA
UTILITIES CO.

EXHIBITS

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(The following proceedings were had and made of record, Monday, October 7, 2002, commencing at 9:00 a.m.)

MR. HOBERG: Let's begin. Let the record show it's approximately 9:00 a.m. on October 7, 2002. This is the time and place scheduled in the Public Service Commission hearing room in the State capital in Bismarck, North Dakota, for the hearing in the matter of the application of Montana-Dakota Utilities for a natural gas rate increase.

In June of this year the Office of Administrative Hearings received a request from the Public Service Commission to provide an administrative law judge to preside in this matter. My name is Allen Hoberg, and I've been duly designated as the procedural hearing officer to preside today.

Let's start with the appearances of the parties for the record in this matter, beginning with the applicant, followed by the Commission staff. Will counsel please state their appearances? Mr. Pearce, please.

MR. PEARCE: Yes. Thank you. William P. Pearce of Pearce and Durick, in Bismarck, appearing on behalf of the applicant, Montana-Dakota Utilities

Company.

MR. HOBERG: And who do you have with you?

MR. PEARCE: With me to my left is Mr. Don Ball, manager of regulatory affairs for the company, and to his left is Mr. Douglas Schulz, who is an attorney with the company, also appearing for the company.

MR. HOBERG: Thank you. You have a number of witnesses today.

MR. PEARCE: Yes. We have nine witnesses altogether.

MR. HOBERG: Thank you, Mr. Pearce. Mr. Binek, please.

MR. BINEK: My name is William Binek. I'm counsel for the Public Service Commission. I'm representing the Commission advocacy staff in this proceeding. Seated to my right is Mr. Charles King, a Commission consultant, and to the right of Mr. King is Michael Majoros, another consultant. And at the end of the table is Patrick Fahn, a public utility analyst with the Public Service Commission.

MR. HOBERG: Thank you, Mr. Binek. Is there anyone else present today who may wish to give testimony, either for or against the application?

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Anyone else present? No one else present.

Then, of course, to my left we have members of the Public Service Commission. To my immediate left, Commissioner Leo Reinbold, and then Commission President, Susan Wefald, and Commissioner Tony Clark.

And starting with Commissioner Reinbold, who has the natural gas portfolio, I'll ask for your opening comments, please.

COMMISSIONER REINBOLD: Thank you. Good morning, and welcome. It's good to see so much interest. It's an interesting case. We're here to determine what needs to be allowed and also what must be disallowed. That's our job. We're here to do that by being fair to all parties concerned and get done by Noon because everyone has a plane to catch. Welcome.

COMMISSIONER WEFALD: On Wednesday?

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

COMMISSIONER WEFALD: Good morning. We know that this case is very important, both to the company and to the consumers of North Dakota, and we're looking forward to getting a good record. Thank you.

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MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

COMMISSIONER CLARK: Good morning. I look forward to hearing the testimony. Thank you.

MR. HOBERG: Thank you. Just for the record, our court reporter is Linda Gingery today.

Just a very brief summary of the application. It's set out very well in the notice of hearing. On April 12th of this year MDU filed an application to increase its rates for natural gas service by an amount sufficient to provide increased total annual revenue of $2,844,132. And then the rest of the proposals are adequately set forth in the notice of hearing, and I won't go through the rest of those today.

But on June 5th of this year, the Public Service Commission issued a notice of hearing, notice of public input sessions and notice of intervention deadline. And the notice of hearing scheduled a hearing for today and, of course, that's why we're here.

It's my understanding there have been no petitions to intervene in this matter filed with the Commission. However, there were public input sessions held via interactive television on July

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15th of this year at Noon, Central Daylight Time, and giving members of the public an opportunity to express their concerns. And those sessions were held at Bismarck State College, Dickinson State University, Minot State University, Lake Region State College, North Dakota State Hospital, and Williston State College.

The issues, according to the notice of hearing, to be considered in this matter include:

Number 1: What is the value of MDU's property, used and useful, for the service and convenience of the public of North Dakota?

Number 2: What is MDU's rate of return on this property, used and useful, for the service and convenience of the public of North Dakota?

Number 3: What is the just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

Number 4: What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public of North Dakota?

Number 5: Are MDU's rate schedules

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designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

Number 6: Any other relevant information or proposals concerning the proceeding.

The hearing procedure today will be as follows: I'll first call on the applicant to present its case for the granting of the application. And Mr. Pearce has stated that he has nine witnesses on behalf of the company today. Each witness called by the applicant will be subject to cross-examination by Commission staff and by the Commission. And following the direct examination then by Mr. Pearce, cross-examination by Commission staff and questions by the Commission, I'll allow such further questions of the witnesses as are necessary.

Upon completion of the applicant's case, I'll call on the Commission staff to present its case. And Mr. Binek has informed us that he has two witnesses. It will be the same procedure there; direct examination by Mr. Binek, cross-examination by Mr. Pearce, questions by the Commission staff, and then such further questions of the witnesses as are necessary.

I think probably most of the evidence that's being offered today has already been docketed. Probably some additional evidence, too. And that will be offered also, though, and the docket number indicated when it's offered. And we'll mark the exhibits consecutively, 1 through whatever, and also indicate the docket number for those that have already been docketed. If there are additional exhibits being offered, we need seven copies for the record today.

No decision will be reached on this matter today. The proceedings are being transcribed and tape-recorded and will be reviewed by the Commission later. And, thereafter, the Commission will issue findings of fact and conclusions of law and an order as to whether the application should be issued, denied, or as to other appropriate administrative action.

If the party doesn't agree with the final decision of the Public Service Commission, they may have appeal rights or other rights under North Dakota Century Code Chapter 28-32, which is known as The Administrative Agencies Practices Act, or under the Rules of Commission, North Dakota Administrative Code, Article 69-02.

The issues today are as I previously stated. The burden of proof is on the applicant to show by the preponderance of the evidence, also known as the greater weight of the evidence, that it is entitled to a grant of the application it seeks.

Any questions about the procedures today? Mr. Pearce?

MR. PEARCE: No, sir. Except to point out that we will have our rebuttal case basically to put on after the staff's case.

MR. HOBERG: Correct. Thank you. Yes, there will be a rebuttal case presented. Mr. Binek?

MR. BINEK: Nothing.

MR. HOBERG: Just one other housekeeping item. There was a trade secret protection application filed in this matter and an order issued, so I would appreciate it if counsel would keep me apprised of when something that needs trade secret protection is going to be dealt with and we can deal with it appropriately. All right.

Mr. Pearce, do you have an opening statement to make?

MR. PEARCE: Yes, I do. I've got a brief opening statement I'd like to read.

MR. HOBERG: Please proceed.

MR. PEARCE: This case is an application by Montana-Dakota Utilities Company seeking the Commission's approval of an increase in its residential and firm general service gas rates that would generate an additional $2,844,132 in operating revenues, which is about a 4.1 percent overall increase. This increase is required to enable the company to continue to provide safe and reliable service to its approximately 83,500 customers in the state.

As the company's testimony in the case will show, the need for the increased revenue is driven by the necessity of meeting increases in the operating expenses of its gas distribution facilities in North Dakota. The company also needs an adequate permitted rate of return on the company's property devoted to gas distribution operations for it to be able to attract sufficient capital and maintain the quality, reliability and safety of its gas distribution services.

The last general rate increase was authorized by the Commission in November 1994, and it was a decrease in the gas rates as a result of a settlement that took effect in January 1999. This proceeding, of course, does not address the cost of

gas itself which the company acquires for distribution in its system. That's simply a pass-through component of the rates handled by the automatic adjustment procedures.

The list of company witnesses and the areas covered by their testimony will be summarized in the opening testimony of Mr. Wayne Fox, the company president.

One of the major components in the operating expense of the company is the depreciation expense allowance and that is a major factor in this case. The staff has done a curious thing not seen in the normal rate case proceeding. They have taken the depreciation study used in current rates and critiqued a very small portion of it, with the outcome being lower depreciation charges. This is not appropriate to base depreciation on a piecemeal critique of that study. We feel -- the company's position, as will be described by its witnesses, is it's premature at this point to make adjustments to the present depreciation rates which are based on a thorough depreciation study done by Stone & Webster in 1991. And they have been previously recognized by the Commission and applied in the previous rate case. The staff has not prepared a proper

depreciation study and no adjustment of the depreciation rates should be entertained by the Commission in this proceeding.

In addition, the question of the applicability of what's called FAS 143; that is, Financial Accounting Standard 143, will arise in the testimony that's already been filed in this case. This is a new financial accounting standard applicable to North Dakota's public utilities at the end of the year. FAS 143 will require companies to charge -- sorry -- to change the method of accounting for the expected retirement costs of an asset over the asset's useful life. FAS 143 is a very new and untested procedure at this point and the industry is currently engaged in a great deal of analysis and debate as to how and in what manner it should be implemented.

The implementation of 143 in North Dakota is not a matter which should be or reasonably can be addressed as an ancillary matter in a rate case involving a single utility company like Montana-Dakota operating in North Dakota. FAS 143 is a much broader matter than the specific issues in a single company rate case and many decisions need to be made before it can be effectively implemented.

We feel this complex question can only be properly addressed in a generic rulemaking proceeding by this Commission, in which all the utilities operating in North Dakota may participate and present their views on the question. For this reason, our position is that the Commission should not address FAS 143 in this case, but should defer that issue to its proper place in a separate rulemaking proceeding that would involve all the other utilities in which questions relative to the implementation can be addressed in an appropriate setting.

With that background, MDU makes -- moves the Commission to defer any action on FAS 143 in this proceeding and set the matter, that accounting standard for a generic rulemaking proceeding at some appropriate point in the future.

With regard to the design of the proposed rates, the company has proposed changes to accomplish the objectives of providing a measure of stability during periods of admirable weather; being user-understandable for consumers, being simple to administer, and providing for enhanced fixed cost recovery.

We have also included an alternative proposal in the event the Commission finds the primary proposal unacceptable. The company urges the Commission to accept the primary proposal as it provides the best fit with the objectives. However, should the Commission not adopt the primary proposal, the company urges the Commission to adopt the alternative proposal that will be discussed in the testimony.

MR. HOBERG: Thank you, Mr. Pearce.

Mr. Binek, do you have any opening to make, perhaps in response to the motion to defer in regard to FAS 143?

MR. BINEK: I'd like to make a couple comments.

First of all, I think it's appropriate to consider FAS 143 and its implications to MDU. Secondly, with regard to depreciation, depreciation is a major issue in this case. MDU would like to have the Commission defer any consideration on depreciation until it completes a depreciation study that I understand is presently in progress. The staff's position on that has been and continues to be that if a part of the case, and a very important part of the case, is not -- or should not be considered at this point, none of the case should be considered at this point.

There are other important issues in this case as well, such as the rate of return that the company should be allowed. We are far apart in our recommendations on that. The company is asking the Commission to allow a return on equity that is in excess of anything that we have seen, either in North Dakota or around the country for that matter. On the other hand, the recommendations of the Commission's consultants are in line with what is occurring not only in North Dakota, but across the country as well.

MDU's application is a bit curious because MDU's gas earnings have been very stable and are very reasonable at the present time. And it doesn't appear that MDU is in any need of any increase, but that will be determined by the Commission in this proceeding.

I think that's all I have.

MR. HOBERG: Thank you, Mr. Binek.

Mr. Pearce, I understand your motion to defer is a formal motion?

MR. PEARCE: Yes.

MR. HOBERG: And I would advise the Commission to take that under advisement and I don't know if a ruling on that is necessary right now, but

something to take under advisement as part of this proceeding. You don't expect a ruling?

MR. PEARCE: No, that's what we anticipated.

MR. HOBERG: All right. Thank you both.

Would you like to call your first witness, please, Mr. Pearce?

MR. PEARCE: Thank you. I think I'm going to ask, just for convenience, the application and supporting statements are already filed, but in case they need to be referred to, I'd like to mark those as Exhibits 1 and 2, the two books.

MR. BINEK: Your Honor, the direct testimony is not shown as separate docket entries so perhaps they be should be identified separately as exhibits.

MR. HOBERG: That's what we're going to do, but the application, I believe, is marked as Exhibit 1-Docket 3.

MR. PEARCE: Right.

MR. HOBERG: And what was the other document?

MR. PEARCE: Statements A through O. And that's going to be Exhibit 2 and it's also Docket 2.

MR. HOBERG: Is that all the direct?

MR. PEARCE: That's simply the application and statements. The direct will be, I believe, Exhibits 3, 4, 5, 6, 7, 8, 9, and 10. And it's the seven direct -- prefiled direct testimony. It's all in one, single book there, but I think that will have the next seven exhibit numbers.

MR. HOBERG: Let's go off the record.

(Exhibits 1, 2, 3, 4, 5, 6, 7, 8, and 9 were marked for identification.)

(Discussion off the record.)

MR. HOBERG: Okay. The packet that we have of all of the direct testimony of Montana-Dakota Utilities is marked on the outside as Docket No. 1, and the inside of each of the -- direct testimony of each of the witnesses will be marked consecutively as 3 through 9, and that's how we'll be referring to them during the presentations then.

Mr. Fox is the first witness?

MR. PEARCE: Yes, he is.

MR. HOBERG: Mr. Fox, please.

Please be seated. As you know, I'm required by law to tell all the witnesses at administrative proceedings that the maximum penalty for perjury in this state is a Class C felony, punishable by a maximum five years imprisonment, $5,000 fine, or both.

Mr. Fox, being advised of the penalty for perjury, do you promise to tell the truth in this matter? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce, please.

C. WAYNE FOX,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Would you please state your name and your business address?

A. My name is C. Wayne Fox. My business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Company?

A. I am president of Montana-Dakota Utilities, a division of MDU Resources Group, Incorporated.

Q. What are your duties and responsibilities with Montana-Dakota?

A. I have executive responsibility for the development, coordination and implementation of the

strategies and policies relative to all areas of operation.

Q. Would you please outline your educational and professional background?

A. In 1964 I received a Bachelor of Science degree in electrical engineering from Chicago Technical College, Chicago, Illinois. I received a Master of Arts degree in business administration from the University of Illinois, Springfield, Illinois in 1975. Upon graduating from college in 1974, I joined the Illinois Commerce Commission, the state body regulating public utilities in Illinois, as an electrical engineer.

Upon termination of my employment with the Illinois Commerce Commission in June 1980, I was serving as manager of the public utilities division. In that capacity my duties included testifying in formal cases before the Commission, formulating and coordinating Commission policies on technical and administrative matters, processing formal and informal cases, and advising the Commission on matters related to the regulation of public utilities operating in the State of Illinois.

In June 1980 I joined Montana-Dakota as assistant treasurer, regulatory affairs, retaining

that position until May 1982 when I was elected assistant vice-president, regulatory affairs. In May 1985 I was promoted to vice-president, regulatory affairs. In May 1987 my duties were broadened to include the company's purchasing and general services activities. At that time my title was changed to vice-president, regulatory affairs and general services. I assumed my present position in August 2000.

I also have been involved with the activities of the Electric Power Research Institute, the Edison Electric Institute, and the American Gas Association.

Q. Have you testified before this Commission and other state regulatory bodies?

A. Yes. I have previously sponsored testimony before this Commission, the Montana Public Service Commission, the Wyoming Public Service Commission, Minnesota Public Utilities Commission, and South Dakota Public Utilities Commission. In addition, during my tenure with the Illinois Commerce Commission, I testified in a number of cases before that Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide

an overview of our North Dakota natural gas operations, explain our request for a gas rate increase, and discuss the policies and reasons underlying the major aspects of the request. I will also identify the company witnesses in this proceeding.

Q. Would you provide a summary of Montana-Dakota's gas operations in North Dakota?

A. The North Dakota natural gas distribution system serves approximately 83,500 customers in 76 communities. The customer mix is about 86.5 percent residential, 13.3 percent firm commercial, with the small interruptible and large interruptible customers making up two-tenths percent of customers. In addition, gas is provided to the U.S. Air Force Base at Minot and a location in northeastern North Dakota. The residential, firm commercial, and small interruptible customers use natural gas primarily for space and water heating.

As such, Montana-Dakota's system has a low load factor with peak gas requirements occurring during the winter, with summer loads being small by comparison. The total annual gas used by North Dakota customers is 18.3 megadecatherms as projected for 2003 in this case. Consumption by customer

class is as follows: 43 percent residential, 31 percent firm commercial, 8 percent small interruptible, 12 percent large interruptible, and 6 percent U.S. Air Force.

Montana-Dakota's North Dakota gas service area is divided into two operating regions, with regional offices located in Bismarck and Dickinson. In addition, there are a number of district offices located in communities throughout the state. As of December 31, 2001 the company had 587 full and part-time employees who live and work throughout our North Dakota electric and gas service area.

Q. Mr. Fox, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for a gas rate increase?

A. Montana-Dakota is requesting an increase in general gas rates at this time because the current cost of providing natural gas service to our North Dakota customers is not adequately reflected in the -- excuse me -- is not accurately -- adequately reflected in currently authorized rates. It should be noted that this application does not include any cost changes related to the cost of gas which is

handled through the Commission authorized Purchased Gas Cost Adjustment tariff.

Q. Would you please explain the basic elements that make up the total costs of providing gas service and which of these elements is subject to regulation by this Commission?

A. Yes. The cost of providing natural gas service can be best broken down into two major categories. First, the cost of the gas delivered to the town border station where it leaves the interstate or intrastate pipeline and enters our distribution system. And, second, the cost of delivering the gas from the town border station through our distribution system to the individual customers. We call this portion distribution costs or non-gas costs.

Natural gas purchased from a producer or supplier is a commodity like wheat or corn and prices are not regulated. The charges for moving the gas to our distribution system on the pipeline system are regulated by the Federal Energy Regulatory Commission or other regulatory agencies. These two elements which we call, quote, unquote, gas costs, are passed on to our customers on a dollar-for-dollar basis as specified in the

Purchased Gas Cost Adjustment Tariff, and there is no profit made by Montana-Dakota. This portion currently comprises about 66 percent of a typical residential bill for gas services.

The distribution cost of our rate is regulated by this Commission and is the subject of this proceeding. This portion includes operation and maintenance expenses, depreciation, taxes, and a component for the opportunity to earn a return on the investment we have in facilities to provide natural gas service. The distribution costs are currently about 34 percent of a typical residential bill. The last time this portion of the rates increased was in 1994.

Q. What is the amount of the increase requested?

A. As will be fully explained by other company witnesses, the company is requesting an increase of $2,844,132 based on a projected 2003 test year.

Q. How will the requested increase affect the various classes of customers?

A. The proposed percentage change in rates by customer class is as follows: Residential, 4.6 percent change; firm general service, 4.6 percent; Air Force, zero; small interruptible, a negative 4.1

percent; large interruptible, zero, for a total increase of 4.1 percent.

Q. What are the primary reasons that Montana-Dakota needs an increase at this time?

A. The primary reasons are increased operating expenses, operation and maintenance costs, depreciation and taxes other than income and a higher required return on equity.

Q. When was the last general rate increase for Montana-Dakota?

A. Montana-Dakota's last gas -- I'm sorry. Montana-Dakota's gas rates were last increased in November 1994. The increase was $565,000 annually and was authorized in case No. PU-399-94-297.

Q. Have the gas generates changed since that time?

A. Yes. In case number PU-399-96-325 the gas generates were decreased by $800,000 or about 1.2 percent as a result of a settlement accepted by the Commission with a lower rate becoming effective January 15, 1999.

Q. Would you please explain how Montana-Dakota has been able to hold the gas rates down since 1994?

A. From 1994 through 2001 the Consumer Price Index has risen almost 20 percent. In spite of this

increase, we have been able to hold the line on our gas rates by finding ways of operating our business more efficiently and taking advantage of new technology where it makes economic sense to do so. For example, we have created a customer service center in Bismarck representing a one-stop shop for our customers. And we have installed computers in our servicemen's trucks allowing them to receive orders electronically, resulting in savings of at least one hour per day. We continue to look for opportunities to reduce costs and increase efficiencies. However, we now find ourselves in a position where despite our efforts, our best efforts, we must seek rate relief.

Q. What policy changes are proposed by the company in this filing?

A. We are proposing a change in policy regarding service lines. Montana-Dakota is proposing to own all service lines on a prospective basis. Currently, Montana-Dakota owns the service lines in the communities designated as rate zone 2 in its tariff. The customers currently own the services lines in the communities designated as rate zone 1. We are proposing that Montana-Dakota own and pay for, subject to appropriate extension policy

considerations or conditions, all new and replacement service lines on a prospective basis. This change will remove the distinction between rate zones 1 and 2 and will serve as a uniform policy on a statewide basis for all of our service areas. It will also align the ownership of the service line with the responsibility for ongoing testing and maintenance of the lines, which rests with Montana-Dakota and will avoid customer confusion and frustration in those instances when a replacement is necessary.

Q. Is Montana-Dakota proposing changes in its rate structure in this proceeding?

A. Yes. The proposed changes in the rate structure, which will be fully described by other witnesses, accomplish the objectives of providing a measure of stability for our customers, being simple to administer, and providing for enhanced fixed cost recovery.

I should note that our witnesses also present an alternative proposal in the event that the Commission finds the primary proposal to be unacceptable. The alternative proposal is fully described in the testimony of other witnesses. I would urge the Commission to accept the primary

proposal, as it provides the best fit with the objectives noted above.

Q. Will you please identify the other witnesses who will testify on behalf of Montana-Dakota in this proceeding?

A. Yes, I will. I should note at line 22, Mr. Pearce, that there's a correction. We should strike the word "electric" appearing in the last line thereof and substitute the words "natural gas." I will finish my answer.

In addition to myself --

MR. HOBERG: Mr. Fox, I'm sorry to interrupt you, but just for the court reporter's benefit, all the names, of course, are listed in the prefiled testimony. Please continue.

THE WITNESS: Stephen Gaske, President of Zinder Companies, Incorporated, will testify regarding the appropriate cost to common equity and overall cost of capital for Montana-Dakota's natural gas operations. Mr. Craig A. Keller, vice-president, controller and chief accounting officer for Montana-Dakota, will testify regarding the capital structure and overall debt and preferred equity costs. Ms. Rita A. Mulkern, regulatory analysis manager for Montana-Dakota, will testify

regarding the total revenue requirements necessary for Montana-Dakota's North Dakota gas operations.

Mr. Richard A. Espeland, vice-president, human resources for MDU Resources Group, Incorporated, will testify regarding the supplemental income security plan. Mr. Russell A. Feingold, managing director of Navigant Consulting, Inc., will testify regarding certain rate design policy matters. And Ms. Tamie A. Aberle, pricing and tariff manager for Montana-Dakota, will testify on the specific rate design proposals.

Q. (MR. PEARCE CONTINUING) Mr. Fox, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable because they are reflective of the total cost being incurred by Montana-Dakota in providing gas service to its customers. The proposed rates will allow Montana-Dakota the opportunity to earn a just and reasonable return on its North Dakota gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

Q. And to the best of your information and belief, does the testimony you have just given

coincide with the prefiled direct testimony that's marked as Exhibit A?

A. It does.

Q. Did you prepare that testimony originally?

A. I did.

MR. PEARCE: I'll offer Exhibit A at this time -- Exhibit 3. I have no further questions of this witness.

MR. HOBERG: Any objection to Exhibit 3, Mr. Binek?

MR. BINEK: No.

MR. HOBERG: Exhibit 3 is admitted.

Mr. Binek, do you have any questions on cross-examination?

MR. BINEK: Yes, I do.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Good morning, Mr. Fox.

A. Morning.

Q. Does MDU calculate its earned return each year for its North Dakota gas operation?

A. We do.

Q. What was the company's earned return on its gas operations during each of the years 1998, 1999, 2000, 2001?

A. I don't know right offhand. I can certainly provide that to you. We've filed an annual report with the Commission each and every year. I do know for 2003 without this rate increase, we would be a negative 4 percent.

(Exhibit 10 was marked for identification.)

Q. (MR. BINEK CONTINUING) Mr. Fox, I show you what has been marked as Exhibit 10 and ask if you can identify that exhibit? First of all, I guess I should ask if you've seen that previously?

A. I have not.

Q. Okay. Do you recognize that as an exhibit that has been docketed in an MDU case by the Public Service Commission?

A. I do not.

MR. HOBERG: Mr. Pearce, did you get a copy?

MR. PEARCE: No, I didn't. I'm wondering what it is.

Q. (MR. BINEK CONTINUING) Can you identify what the exhibit is, please?

A. It's a memorandum, internal memorandum, I believe, written by Mike Diller of the Commission staff, and it's written to Commissioners, Illona and Bill. And --

Q. What is the date of that document?
A. September 3rd, 2002.
Q. Okay. And what does it refer to?
A. It refers to 2001 annual reports.
Q. And in that document there are a number of companies listed, including MDU Gas, and it shows returns on equity earned by utilities for the four years that I had asked you about; is that correct?
A. It does.
Q. Do you have any reason to doubt the figures that are shown in that exhibit?
A. I do not.
Q. And would you accept the figures shown on that exhibit subject to check, subject to your own verification?
A. I would.
Q. What is the ROE shown for the year 1998 for MDU?
MR. HOBERG: I think we better have it offered and admitted before we testify.
MR. BINEK: I'm sorry. I will offer Exhibit 10.
MR. HOBERG: Any objection to Exhibit 10, Mr. Pearce?
MR. PEARCE: I guess I'm tempted to object

for lack of foundation since the witness who prepared it is not being offered, but given that Mr. Fox has indicated he would accept the numbers subject to verification, I don't have any objection.
MR. HOBERG: Okay. Exhibit 10 is admitted. Mr. Binek, please.
MR. BINEK: Thank you.
Q. (MR. BINEK CONTINUING) Now, Mr. Fox, would you -- for the year 1998 what is the ROE shown for MDU gas?
A. 14.55.
Q. And 1999?
A. 10.25.
Q. 2000?
A. 11.92.
Q. And 2001?
A. 11.90.
Q. And what is the four-year average?
A. 12.16.
Q. Okay. And it's your position that -- is it your position that an 11.9 return on equity is inadequate?
A. Dr. Gaske in this case has pointed out that because of the risk associated with our gas business, we should be earning considerably higher

than 11.9.
Q. So the earnings that you had in 2001, 11.9 were inadequate; is that your testimony?
A. That's correct.
Q. And the four-year average of 12.16 is adequate; is that also your testimony?
A. Let me explain that. It's inadequate based upon Dr. Gaske's testimony in this case, but keep in mind, that we are dealing with 2002 and 2003 is just right around the corner and we know based upon our rates-of-return analysis that we will be earning a negative rate of return for 2003 without the proposed rate increase. In fact, in 2002 we will be at zero. So we've had a drastic change in the last two years.
Q. Will the 2002 return be influenced by the very mild winter we had last year?
A. This is normalized.
Q. Okay. And what is your predicted return for 2002 under normalized weather conditions?
A. I believe it's zero. We have witnesses here which can attest to that and subject to check. It's considerably lower than what you find here for 2001.
Q. Is it true that you are predicting a

significant decline in your earned return between now and the end of 2003?
A. I am.
Q. Okay. On page 6 of your testimony you mentioned that the last gas rate increase was in 1994, and that that was a relatively small increase, $565,000. What did that amount to in percentage terms?
A. I don't recall.
Q. Okay. In 1999 you had a rate reduction of 800,000. Do you know what the percentage reduction was then?
A. In my testimony I say about 1.2 percent.
Q. Okay.
MR. HOBERG: Mr. Binek, can you bring your microphone over closer? It's on, isn't it?
MR. BINEK: Yeah.
Q. (MR. BINEK CONTINUING) Earlier this year the Commission reduced your electric rates; isn't that correct?
A. It did.
Q. What is it about the gas business that causes it to require an increase when the electric side of your operations justify a rate decrease?
A. Well, they're really two different

businesses. Dr. Gaske, I think in his testimony laid out very well the reasons. You know, we're a small gas utility --

MR. HOBERG: I'm sorry. Mr. Fox, can you bring your microphone a little closer, too? They are having a little trouble hearing both you and Mr. Binek in the back.

MR. BINEK: We're both soft-spoken.

THE WITNESS: Can you now hear me better?

MR. HOBERG: Yes. We can hear you upfront. It's just having trouble back --

THE WITNESS: I'll try to do better. We also have competition for alternate fuels. And, thirdly, we have a rate design that's in effect right now that doesn't allow us to fully recover our fixed cost of operations. And so Dr. Gaske does a good job of looking at that and I happen to agree with what he said. He said, I think, in his testimony that because of the smallness, which means that, you know, small change in one of our expense items or whatever creates a big difference in whether we are able to earn a return or not, an adequate rate or return on our business. And he said that's worth 100 basis point in and of itself simply because we're that small.

Q. (MR. BINEK CONTINUING) You mentioned competition from alternate fuels. What competition do you face from alternate fuels?

A. Propane, coal, and --

Q. How --

A. Excuse me. Gas bypass.

Q. How much competition do you face from coal?

A. Well, I have a neighbor -- I'll be happy to supply some of that, but we do have some competition. In fact, I've got a residential customer in my neighborhood that uses coal.

Q. It's very, very minimal, isn't it?

A. It is from a residential standpoint, but keep in mind that folks like the larger customers, such as out here at the Tesoro -- did I say that correctly? Amoco --

COMMISSIONER WEFALD: Tesoro.

THE WITNESS: Tesoro is, in fact, looking at that very option, whether to burn coal or continue with gas, and we, in fact, have lost a portion of that gas load now to gas bypass.

Q. (MR. BINEK CONTINUING) Propane, aren't you, in fact, putting in -- extending your natural gas delivery systems in the Bismarck area out into areas previously served by propane?

A. We are, but we're not picking up, you know, 100 percent or even 90 percent of that.

Q. But you are picking up a good majority of the customers out there that were previously on propane, aren't you?

A. We're primarily picking up those customers who have yet not committed, picking up the new customers. We're hoping for a conversion rate around 60 percent on propane out there. Certainly not the 100 percent. So how pervasive it is, it's there and continues to be there.

Q. Okay. So you had 100 percent of the customers out there using propane prior to extending your lines, now you're going to -- you're hoping to acquire 60 percent of those people presently using propane, is that --

A. Or said another way, Mr. Binek, we will lose 40 percent of that load out there or not be able to --

Q. Well, you're going to gain load out there that is presently served by propane, right?

A. That's correct.

Q. Okay.

A. My statement is also correct, too.

MR. HOBERG: Mr. Binek, your question -- I

don't know that we sufficiently defined what "out there" means.

Q. (MR. BINEK CONTINUING) I'm thinking specifically about areas north of Bismarck where lines are being -- distribution lines are being extended by MDU gas.

A. For the record I would clarify. We do have a new project. We call it the northeast Bismarck project, where we are spending monies to provide gas service to customers in that area, that hopefully will have some growth, plus pick up some of the ones that are now using propane.

Q. Thank you.

MR. HOBERG: Thank you.

Q. (MR. BINEK CONTINUING) And the other competitive fuel is oil?

A. Could be. For the larger customers you have coal, oil, bypass, primarily.

Q. Okay. The bypass would be served by the Williston Basin Interstate Pipeline?

A. That's one bypass that I'm thinking about. They actually went to Williston Basin.

Q. Okay. And that's an MDU Resources company?

A. It is, but it's money out of my pocket.

Q. Sure. I understand that. Has inflation

accelerated since 1994?
A. Yes, it has.
Q. Do you have any basis for assuming that inflation will accelerate between now and the end of 2003?
A. When you say accelerate, I'm not sure. We know we have inflationary pressures of probably three, three and a half percent per year.
Q. Will it get worse?
A. I have no idea.
Q. On page 7 of your testimony you state that you have so far avoided a rate increase by operating your business more efficiently and taking advantage of new technology. Have you suddenly lost the ability to operate more efficiently?
A. If I may, I'll go back in history a little bit. In 1994 we had our last rate increase application in here. Since that time, our employees -- we've had a decrease in our employees of over 30 percent. And that hasn't come about by huge layoffs. That came about by attrition and finding more efficient ways of doing things. Another statistic that I like to think about is -- let me check my notes here, if I can find it real fast -- is that in 1994 one employee -- I'm sorry --

248 customers was being served by one employee. In 2001 one employee was serving 370 customers. Just means that we've tried to find better ways of doing that.

And we continue to look for that, but I don't foresee us continuing that type of rapid growth in trying to achieve efficiencies that would mark that rate of serving more customers with less employees. In fact, we've kind of flattened in the last year or two. I think there is just so much that you can do. Although, I can tell you we have our employees out there looking for it. And that's where most of our ideas come from, is from our employees. And we have several programs that are geared to do that, to reward and provide some incentive for coming forth with ideas, and most of them are just recognition-type things.

Q. Have you exhausted all possible new technologies that might help you cut costs?
A. Again, probably not, but keep in mind, Mr. Binek, if I may -- can you still hear me all right?

MR. HOBERG: Yes.

THE WITNESS: -- is that we -- and, here again, to give you an example, we are small. And,

again, to give you an example of what that smallness can do for you, we had hoped to automate our meter reading across our entire service area, including that of North Dakota, but we find out with the sparseness of our operation and given that we serve very few so-called large towns, Bismarck, Billings, Montana being the largest ones, Rapid City, we certainly -- we could not commit the monies that would have been necessary to do that. So we went halfway. We decided to upgrade our semiautomatic ICON meter reading system to, again, accord new technology, but certainly not to the point where we would have liked to.

So it's looking, but it's -- you know, you look at all across that business venture, I don't see anything on the horizon other than what we've done today, such as the customer service center, automating and consolidating our meter reading. We do joint trenching. You know, we just keep looking under every little piece of dirt, so to speak, to try to figure out ways of doing it. But when you say "all," no, I wouldn't say all, but certainly we have come a long ways in the last five, six years.
Q. (MR. BINEK CONTINUING) As far as numbers of customers, have you been gaining in customer

count?
A. Not particularly.
Q. You have had some gains?
A. We have had some gains, but nothing materially. We grow about 1 percent or less per year in the gas business. Unless we take on a new project like northeast Bismarck, there isn't a lot of growth other than that.
Q. Could you explain what joint trenching is?
A. That means we get together with telecommunication companies, other utilities, anybody that's putting a hole in the ground and trenching it for a ways, we'd like to drop our underground facilities in there as well and that's worked out very well for us.
Q. So you're doing that right now?
A. We are doing that now.
Q. Are you doing that in northeast Bismarck as well?
A. We are wherever the opportunity comes along, especially with the telecommunications people, but that's slowed down, too.
Q. On page 7 of your testimony you propose a policy change with regard to the ownership of customer services. Does that policy change

influence your need for more revenue and, if so, how?

A. It does. We think we'll spend about -- other witnesses have it. It's about $500,000 a year, and that's included in this case.

Q. On page 8 you mention rate structure changes. Do those rate structure changes influence your need for more revenue and, if so, how?

A. It does not.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, do you have any questions of Mr. Fox?

COMMISSIONER REINBOLD: A couple. Thank you.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. First of all, I want to get back to the residential customers burning coal in the City of Bismarck. Do you have any idea the numbers you're talking about, the number of households that are taking advantage --

A. It would be very small for the residential. I happened to use that. I kind of bristle at that every time I go by that person's home. That's the

reason I brought it up. But the coal, the competitive feature of that would be in the large customer list. And the reason for that, if the cost of gas goes up -- and primarily we're talking about the cost of gas that we don't control. We're talking about the wholesale. But if that would go up materially, then those folks start looking at different alternatives. The distribution portion of it doesn't have much influence on this.

Q. The reason I wanted to bring it up again is because it surprised me. I didn't know that happened.

MDU, you have gas operations in other states other than North Dakota. You have Montana?

A. Montana, South Dakota, and Wyoming.

Q. And are they in a similar calendar mode of applying for a rate increase, or don't you know?

A. Yes. In every state we are filing for a rate increase, either have or will. We filed in the State of Montana. We've already received an interim rate increase there. And we expect the process in Wyoming to go rather fast. The idea in most cases, and the other witnesses here will have a better feel for that, but we are hopeful of putting increases on the distribution site, increased rates in effect for

this heating season.

Q. You mentioned your customer service center and we've heard presentations on that. It's fascinating what you're doing. Can you elaborate a bit on what the customer service center does if somebody calls in?

A. Yes. Yes, I can. Am I close enough to this? A few years ago we decided to centralize what we call our customer service point. Historically, we would have a person located in each of our major areas talking to our customers, answering their inquiries, their questions. And we thought that we could consolidate that and still give personalized service to each customer by doing a couple things. One is when they call in, they would get a real person that would be able to meet their needs. And, secondly, through increased training, 8 to 10 weeks of training for each of these people, we thought that they would be able to handle particular questions, inquiries. In fact, they actually dispatch calls to our servicemen, that type of thing, in addition to that.

So we thought we could do that with a decreasing -- without decreasing our request time for service, decrease our customer acceptability. In

fact, I think it's enhanced our customer acceptability since we started that. There are a lot of things that have been very favorable about that and, plus, we've been able to save a considerable amount of money on an annual basis as a result of that.

Q. Better service and save money at the same time?

A. That's correct.

Q. You say when I call in or somebody calls in, you talk to a real person?

A. They do. I say that versus calling, as we sometimes do, call for help and we find that we have to punch one or two or three or four a couple of times in order to get someone to answer our questions and sometimes we never get someone to answer our questions. So we don't do things that way.

Q. Is there any way that you can take your experiences of talking with a real person and teach this to the telephone industry in the state?

A. Well, I didn't mention them by name, but you're right on track.

Q. I could. That's enough insults for now. Next.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. You mentioned Tesoro Company. What impact does this one company have on the income of Montana-Dakota Utilities?

A. Well, we have a witness that would have it. Ms. Mulkern has that in her cost of service.

Q. Then I'll just wait and ask Ms. Mulkern. That's fine. And then each one percent -- we received this memo --

MR. HOBERG: Exhibit 10.

Q. (COMMISSIONER WEFALD CONTINUING) Exhibit 10 from staff. And it shows that 2001 11.9 percent rate of return. In your testimony you have said that you anticipate a rate of return of zero in 2002; is that correct?

A. 2003. No, 2002. 2003 would be negative.

Q. So can you share with me the difference in income or the difference in expenses that would relate to a drop from 11.9 percent to zero?

A. I can, but I think what would be best, Commissioner, if you can wait for Ms. Mulkern to come. She has all the full facts in front of her.

Q. Okay. And then in your expansion into north Bismarck, how are costs recovered for that expansion, and are they included in your cost for 2002 when you anticipate a rate of return to be zero?

A. Northeast Bismarck is included in this rate case.

Q. And what are the --

A. That's a 2003 test year.

Q. And that's a 2003 test year?

A. Mm-hmm.

Q. So what are the costs for that expansion, and how are they recovered?

A. Let's see, how are they recovered? They are included in this rate case so it would be recovered through the rates of all the folks, ratepayers in the State of North Dakota.

Q. Do you have an expansion tariff in place so that the customers in those areas pay the bulk of the expansion, or are the bulk of the expansion costs paid by all the ratepayers of the State of North Dakota?

A. There's a policy in place for that and, again, if I may, Ms. Aberle or Ms. Mulkern could answer specific questions on that.

COMMISSIONER WEFALD: Thank you. That's all my questions.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

EXAMINATION

BY COMMISSIONER CLARK:

Q. Just one question. Do you have any other major expansion plans outside of northeast Bismarck in your service territory area?

A. In North Dakota, Commissioner?

Q. Right.

A. That's the only one I can think of right now. Like I said, the gas business is very slowly growing. It's less than 1 percent per year.

Q. Okay. And that would include both residential and industrial, you don't have any industrial-type expansion projects on the horizon, at least that would be included in this test year?

A. Nothing that -- nothing that we haven't had in the past.

COMMISSIONER CLARK: Okay. That's all I have. Thank you.

MR. HOBERG: Thank you, Commissioner Clark. Commissioner Reinbold, you have another question?

FURTHER EXAMINATION

BY COMMISSIONER REINBOLD:

Q. One other question. Do you serve the University of Mary with natural gas?

A. Yes.

COMMISSIONER REINBOLD: You do. Thank you.

MR. HOBERG: Thank you, Commissioner Reinbold. Mr. Pearce, anything on redirect?

MR. PEARCE: No. I have no questions.

MR. HOBERG: Thank you. Mr. Binek, anything further?

MR. BINEK: No.

MR. HOBERG: Thank you, Mr. Fox.

Let's take about a -- let's be back at 10 after 10:00, about a nine-minute recess. We'll start at 10 after 10:00.

(A recess was taken.)

MR. HOBERG: We're back on the record after a short recess. And I apologize. I neglected to ask for an appearance by Commission advisory staff, and at this time I will ask Ms. Jeffcoat-Sacco to make an appearance for Commission advisory staff.

MS. JEFFCOAT-SACCO: Commission advisory staff in this case is myself, Mike Diller, and Jerry Lein. And for purposes of this case, if there are

some questions of advisory staff during the hearing, I'd request that Mike be able to ask those, if that's acceptable.

MR. HOBERG: Any objection, Mr. Pearce?

MR. PEARCE: No, that's no problem.

MR. BINEK: No.

MR. HOBERG: Did you have any questions of the first witness?

MR. DILLER: I can ask the question I had of one of the other witnesses.

MR. HOBERG: Okay. Thank you, Ms. Jeffcoat-Sacco and Mr. Diller. You may not be asking questions, as I understand, of every witness, but you'll indicate to me if you have a question?

MR. DILLER: That's right.

MR. HOBERG: Okay. Thank you. Your next witness, please, Mr. Pearce.

MR. PEARCE: Thank you. Before I call the witness, I think there's one matter I'd like to clarify. I'm not quite sure what's the best way to do it. It turns out apparently there's a significant error in Exhibit 10. The 2001 MDU gas return does not correspond to the return that was actually filed with the Commission in the annual report. Apparently, it was mistranscribed when this

exhibit was made up, so I'm not quite sure what's the best way to do that. We can take judicial notice of the report that's on file with the Commission.

MR. HOBERG: This is on file in another matter?

MR. PEARCE: This is the annual report that the company has filed and I think Mr. Diller based his Exhibit 10 on. Perhaps maybe since he's now participating in the proceeding, he could simply clarify that there's apparently a transcription error made in preparing Exhibit 10.

MR. HOBERG: Is there an error, Mr. Diller?

MR. DILLER: Yes. I looked at MDU's annual report for its gas operation. It appears I picked up the 2000 number and put it in 2001. The actual earnings reported by MDU, I believe, is 1.6 percent for 2001, rather than 11.9.

MR. HOBERG: 1.6 percent. Why don't we just make that correction there? Is that sufficient, Mr. Pearce?

MR. PEARCE: Yes, that's fine. The report actually says 1.616, but 1.6 is fine.

MR. HOBERG: And then, of course, that would make a difference on the four average, too,

and make a difference on the average for all. For the purpose of this hearing are we mostly concerned about those four numbers from 1998 to 2001?

MR. PEARCE: That was the point of the exhibit, I think.

MR. HOBERG: Okay. Then that exhibit will be corrected as indicated. Thank you, Mr. Pearce. Your next witness, please.

MR. PEARCE: We'll call Dr. J. Stephen Gaske.

MR. HOBERG: Dr. Gaske's direct testimony does appear as Exhibit 4 in Docket No. 1.

Dr. Gaske, did you hear -- you can sit down.

THE WITNESS: I thought you'd swear me in.

MR. HOBERG: I am going to. You can sit down while you're doing it.

Dr. Gaske, did you hear the admonition I gave in regard to perjury?

THE WITNESS: Yes, I did.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce,

please.

J. STEPHEN GASKE,

being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Dr. Gaske, have you prepared and had prefiled in this case prepared direct testimony of J. Stephen Gaske?

A. Yes.

Q. And if you were asked the same questions appearing in Exhibit 4, would your answers be the same today if you gave them live in this proceeding?

A. Yes.

Q. And to the best of your information and belief, is all the information contained in that testimony true and correct?

A. Yes.

MR. PEARCE: I will offer Exhibit 4 at this time and I'm not going to reread the testimony.

MR. HOBERG: Thank you, Mr. Pearce. Any objection to Exhibit 4?

MR. BINEK: No.

MR. HOBERG: Okay. Exhibit 4 is admitted. Are you tendering the witness for --

MR. PEARCE: Yes.
MR. HOBERG: Okay. Thank you, Mr. Pearce. Mr. Binek, do you have any questions of Dr. Gaske?
MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Dr. Gaske, on page 2 of your initial testimony, and that is Exhibit 4, at lines 8 to 10, you state that you have filed cost of capital and capital structure issues in six states, including North Dakota.

Was your latest North Dakota appearance in Case No. PU-399-01-186, which was MDU's electric service rate case?

A. Yes.

Q. In that case did you argue for the inclusion of an upward adjustment in the return to equity to account for flotation costs?

A. Yes, I did.

MR. BINEK: Okay. Your Honor, at this time I would like to have Mr. Gaske refer to some findings in this case. Do you wish to have this marked as an exhibit or just --

MR. HOBERG: Let's take official notice of that. I don't think we need to mark it as an

exhibit.

MR. BINEK: I do have copies, if people would like copies.

MR. HOBERG: That may be a good idea to put copies out for us, please.

MR. HOBERG: And, again, for the record, that's Case No. PU-399-01-186. Mr. Binek, please.

Q. (MR. BINEK CONTINUING) Okay. I've handed you a copy of the decision that the Commission issued in that case. The decision is dated April 24, 2002. And I would ask if you would please read paragraphs 14 and 15.

A. (Witness reviews document.)

MR. HOBERG: You don't want him to read them out loud, do you?

Q. (MR. BINEK CONTINUING) Yes, I would like to have you read them out loud.

A. "Under cross-examination, Gaske provided no empirical data to show that disallowing flotation costs would hinder the issuance of stock. On the contrary, Gaske agreed that most regulatory commissions do not allow flotation costs."

"Given that staff has provided evidence based on historical information, we find no need to rely on the theoretical" --

MR. HOBERG: Dr. Gaske, I'm sorry. Can you speak up a little bit, please? We're having a little trouble.

THE WITNESS: "Given that staff has provided evidence based on historical information, we find no need to rely on the theoretical information provided by MDU. In addition, Gaske admitted that most regulatory commissions do not allow flotation costs. The evidence indicates a negligible amount of flotation costs in the instant case. Therefore, the Commission will not include flotation costs in the determination of return on common equity."

Q. (MR. BINEK CONTINUING) Thank you. Your flotation cost approach in this case is essentially the same as your approach in MDU's electric case that was decided on April 24th of 2002; isn't that correct?

A. Yes, it is.

Q. And it's also correct that the Public Service Commission rejected the inclusion of flotation costs in that case --

A. Yes, that's true.

Q. -- is that correct? And it's also true that most state public utility commissions have

rejected the inclusion of flotation costs in determining the cost of common equity; isn't that also correct?

A. Some have accepted it and some have rejected it.

Q. Most have rejected it; would you agree?

A. At this point, yes.

Q. Where in your direct or rebuttal testimony in this case do we find empirical data to show that disallowing flotation costs would hinder the issuance of stock?

A. I never make the claim that it hinders the issuance of stock. What I do say is that without the allowance, an issuance of stock will result in a confiscation of property of the existing investors. So that's a very different claim than the one that you've asked me about. I don't base my claim on empirical evidence that they will be unable to issue stock. They will be unable to issue the stock on reasonable terms.

Q. Aside from North Dakota, what were the other five states where you filed testimony on cost of capital?

A. Let's see. Montana, Wyoming, New York, South Dakota, and actually I've done it in Alaska.

Q. In how many of those states did you recommend a flotation cost adjustment to the return on equity?

A. All of them.

Q. And how many of those states did the Commission accept your recommendation?

A. Actually, I should add I've also testified on flotation cost adjustment in a property tax case in Wyoming and, in fact, testified on that on two occasions.

Q. Okay. But in utility cases you're talking about the previous ones you mentioned?

A. In utility cases, most of those were settled or have not had a decision. The Montana case they did not allow flotation costs. In the Wyoming property tax case they did not allow it the first time, but the second time around I think I did a better job of explaining it and they did agree that a flotation cost adjustment was appropriate in order to be able to issue common stock on reasonable terms. It's an appropriate part of the cost of capital.

Q. Okay. But that was not a utility case?

A. No, it was not. But my point is that Commissions have rejected this issue in the past and

then turned around and realized and understood the issue so that they did allow it. They changed their minds.

Q. What rates of return did the Commissions allow in gas -- let me go back. Were any of these cases that -- the utility cases that you talked about gas utility cases?

A. Yes.

Q. And how many of those were gas utility?

A. I probably -- I don't recall exactly, but maybe about five of them.

Q. What rates of return did the Commission allow in each of those gas distribution cases?

A. To my recollection, the only one that went to a decision was a Montana case and I believe it was 11.7, but I would have to check to tell you.

Q. Okay. None of them have --

A. It might -- it might have been higher than that. I don't recall.

Q. I'd like to have you turn to your Exhibit JSG-2.

COMMISSIONER REINBOLD: What page is that?

MR. BINEK: It's Exhibit JSG-2.

MR. HOBERG: Toward the end of Exhibit 4, his testimony, about two pages before the end.

Q. (MR. BINEK CONTINUING) On page 1 you provide a number of rates of annual change for prices and gross domestic product. They end in 2001.

MR. HOBERG: I'm sorry. I misspoke. I was on page 8 when I said that. It's closer to about 10 pages from the end, JSG-2.

THE WITNESS: I think you're on the right page.

COMMISSIONER CLARK: Schedule 1.

COMMISSIONER WEFALD: Is it in the rebuttal testimony or the original testimony?

THE WITNESS: Original testimony.

COMMISSIONER WEFALD: Thank you. That will help me find it.

MR. HOBERG: Schedule 1, where it says 1 of 3 pages.

THE WITNESS: I think that's what he's referring to.

MR. HOBERG: Does everyone have it?

COMMISSIONER WEFALD: JSG-2, and which page of JSG-2 are we on?

MR. BINEK: Page 1 of 3.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Mr. Binek, please.

MR. BINEK: It's Schedule 1, page 1 of 3.

Q. (MR. BINEK CONTINUING) Okay. On page 1 you provide a number of rates of annual change for prices in gross domestic product. They end in 2001, which is now more than nine months ago. What has happened to these indicators since last December?

A. I believe in the early part of the year there was relatively rapid growth in the economy. And I believe it slowed down since then, and I don't know what's going on right now. I do know that right now there's a debate whether we're in or going into another recession, but we really won't know that until the quarter is out.

Q. What about consumer prices, what's happening there?

A. I don't have that information.

Q. On page 2 of that exhibit you show a number of interest rates, but your series end last January. Can you provide the latest interest rates and match these series?

A. Let's see. The last one I had was as of the end of July, the corporate average, which was 7.38 in January, went down 11 basis points to 7.27 percent. The A-rated public utilities, which has been 7.66 percent, went down to 7.31 percent. And

the Baa-rated utilities barely changed at all, went from 8.13 to 8.07 percent. Since that time I don't have the exact numbers. I believe the numbers have gone down some. That, I guess, brings you up another six more months.

Q. Okay. So the interest rates generally have decreased; do you agree?

A. Yes. The Baa barely as much, but it's down.

Q. Do you know whether it's true that interest rates are now the lowest that they've been in decades?

MR. HOBERG: By "decades" you mean what, the last --

MR. BINEK: Last couple, three.

MR. HOBERG: Three decades.

THE WITNESS: It depends on what interest rate you're talking about. One of the things that has occurred in the past year is that investors have been very leery of investing in almost anything that has any risk at all attached to it. So they have been reluctant to be in common stocks or even risky bonds. The treasury bill rates are the lowest they've been in decades. The U.S. Treasury bond rates are also the lowest that they've been in

decades. However, if you look at the Baa public utility bonds, right now they're essentially higher than they were in 1999 or '98. Approximately where they were in '97. Higher than they were in '93. They're about where they've been for the last decade.

So to answer your question, depends on whether you're talking about extremely low-risk instruments. Those are low. Investors want those very badly right now because there's a great deal of uncertainty in the market and the economy, but your question is not true if you're talking about public utility bonds.

Q. (MR. BINEK CONTINUING) On page 3 of that same exhibit, you show average return on the book value of equity since 1977 up through 2001. What has happened to returns on equity during the past nine months?

A. I would imagine that they are pretty abysmal, but I don't know the numbers on that.

Q. Okay. On page 11 of your testimony you present the discounted cash flow formula. Is it true that the only difference between your presentation of this formula and that of Mr. King is that you increase the next year's dividend by a

factor of .625 and that Mr. King increases it by .5?

A. As far as the basic general formula, yes, that's correct.

Q. Is the principal reason for this difference your belief that Mr. King has failed to recognize the present value of future dividends and dividend increases?

A. I think that the best way to describe it is that he's neglected to pay any attention to the time value of money during the initial year.

Q. And that's present value, isn't it?

A. Well, the whole discounted cash flow model looks forward basically into an infinite period of time in the future and is based on discounted cash flow. The portion of the model that deals with that adjustment factor really is looking at the first year of an infinite number of years. That dividend tends to be the most valuable because it's one you get the soonest, and to the extent that you're getting it on a quarterly basis, the first one you get is more valuable than the second, more valuable than the third, et cetera, as long as the dividend doesn't change. And so I think the real difference between the two of us is a relatively small one. I recognize the time value of money and he doesn't.

Q. This really doesn't amount to much of anything as far as this case, does it?

A. No. That's why I was a little bit surprised that he put it in his rebuttal testimony.

Q. I recall an electric case we spent a lot of time on this issue for very little money.

A. Yeah. And I couldn't understand why he kept getting the math wrong and still does.

Q. Perhaps he might not think he's got it wrong.

A. It really goes -- it's not a real big dollar thing. It really goes to a question of whether you can do the math right.

Q. I think we'll let him respond to that one.

A. And that may be something -- well, I'll leave it at that.

Q. Please turn to page 5 of Schedule 2 of your Exhibit JSG-2.

COMMISSIONER WEFALD: Same book?

MR. HOBERG: Yes, same book.

COMMISSIONER REINBOLD: What page?

MR. BINEK: Page 5 of Schedule 2.

COMMISSIONER WEFALD: 5 of 9?

MR. BINEK: Of 2. Oh, 5 of 9, yes.

Q. (MR. BINEK CONTINUING) Is this the page on

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which you developed the growth rates you use for your six proxy group companies?

A. These are the factors that I gave the most weight to, yes.

Q. The first column is Zacks five-year growth estimate, and the second column is your retention growth calculation; is that correct?

A. That's correct.

Q. Is it true that for five out of these six companies the Zacks forecast is higher than the retention growth forecast?

A. Yes.

Q. The third column is labeled "weighted average." Is that the weighting of two-thirds Zacks and one-third retention growth?

A. Yes.

Q. On what basis did you decide to make that weighting between the two growth estimates?

A. There were two factors that came into play. One is that I normally think of the retention growth rate as being sort of a baseline, relatively stable number that investors can look at as being a base level of growth throughout the life of the project or the company as long as they maintain that. The Zacks earnings growth estimates take into

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consideration a lot of other ways that a company can grow other than by retaining earnings and reinvesting it to increase common equity just through retained earnings. So the Zacks earnings estimates which are put together by analysts and forecasts tend to include the other methods that companies can grow by. For these companies I think people who buy common stock place a fairly good amount of weight on those estimates and stock prices and dividend yields are dictated to a large extent by those analysts' estimates. So I tended to give them a little more weight.

The second reason I used that approach is that it somewhat mimics an approach that the Federal Energy Regulatory Commission actually requires almost as a generic approach where they give two-thirds weight to the Zacks earnings estimates and a one-third weight to the projected growth in the Gross National Product or Gross Domestic Product, rather than retention growth. So to my mind, it's a good way to put together a combination of the two that smooths out aberrations that may occur in one growth rate or the other and get a pretty good estimate of what investors reasonably expect over a long period of time.

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Q. Isn't it true that two companies, Keyspan and Laclede Group, account for the highest observations?

A. Yes, highest observed growth rates.

Q. And those high growth rates for Keyspan and Laclede rates carry over to the next page, page 6, to yield the two highest rates of return; isn't that also correct?

A. Yes. Keyspan and Laclede also have the highest dividend yields.

Q. Did Mr. King include Keyspan in his comparable companies?

A. No, he did not.

Q. Do you know why Mr. King excluded Keyspan from his group of comparable companies?

A. He used different selection criteria than I did. Keyspan derives less than 75 percent of its earnings from utility operations or gas utility operations.

(Exhibit 11 was marked for identification.)

Q. (MR. BINEK CONTINUING) Would you please identify what has been marked as Document 11? I guess I also would like to say, would that be the cover page, index page, and page 27 of the 2001 form 10-K for Keyspan Corporation?

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A. Yes.

MR. BINEK: I would offer Exhibit 11.

MR. HOBERG: Any objection to Exhibit 11?

MR. PEARCE: No. Assuming it is what it purports to be, I have no objection.

MR. HOBERG: Exhibit 11 is admitted.

Q. (MR. BINEK CONTINUING) Mr. Gaske, I'd like to have you look at the first line of the first column on page 27. Could you tell me what the number there represents?

A. It's the gas distribution revenues of Keyspan during various years in the recent past.

Q. It shows gas distribution revenues in 2001?

A. Yes, it does.

Q. What is that number?

A. 3.6 million.

Q. Now, I'd like to have you drop down a few lines -- is the number billion?

A. Yes. The numbers are expressed in thousands of dollars, so, yes, $3.6 billion.

Q. And now would you drop down a few lines and read the number for total revenue?

A. $6.6 billion.

Q. Would you agree that gas distribution accounts for almost exactly one-half of Keyspan's

total revenue?
A. A little more than that, but, yes. Somewhere in the 50 percent range, 50 to 60.
Q. The other company with very high weighted growth rate on page 5 of Schedule 2 is Laclede? Or I think you refer to as Laclede?
A. Yes.
Q. Okay. Could you explain how Laclede could generate a 12 percent annual growth in earnings when its retention of earnings would allow it to increase by only 4.2 percent?
A. Laclede, at the time that I did my testimony, the most recent Value Line page for them indicates that it had recently formed a holding company and that Laclede was going to begin essentially starting up some new businesses and getting into some other new lines. The Value Line ultimate conclusion was that Laclede's expansion into unregulated industry boosts its long-term earnings prospects.
So although Laclede did not have much in the way of other investments and other lines of business, particularly unregulated ones at the time, and still doesn't have a whole lot, investors were clearly expecting that they would get into some

additional lines of business and that in the long run that they were going to boost their earnings' growth rate above the growth rate that would be sustained by book value growth.
Q. So Laclede's high return is related to unregulated activities; would that be correct?
A. Not the current required return of the company at the time. The high growth rate and perhaps the dividend yield was lower than it might otherwise have been because of that high expected growth rate, but at the time the company was primarily a distribution company.
Q. But the high return that you're showing is due to unregulated activities, isn't it?
A. They didn't have much in the way of unregulated activities at the time. The high growth rate is based on the expectation that in the future they're probably going to make more money than they can make on unregulated operations, but there's a very different question there, because the current return reflects to some degree unregulated operations in the future, but it primarily reflects what they have in place and what their current business is, what their prospects for that business are and the risks attached to it. So you can have

high growth expected in the future without necessarily having a lot of risky investments right now.
In addition, the -- I suspect that at one level it's probably good for the Laclede investors for the company to diversify into a few other lines of business to more or less diversify the company in case something happens with the gas distribution business.
Q. Didn't Mr. King produce as his Exhibit CWK-5 a Zacks report that showed Laclede's consensus growth at 4.25 percent?
A. Yes. Later in the year after I prepared my testimony the projected forecast for Laclede went down. I actually didn't look to see what happened with the other companies, but he did produce the Laclede one and it went down from 12 to 4.
Q. Turning to page 6 of your Schedule 2, would you agree with me that if you left out Keyspan and Laclede, the average return would be considerably less than the numbers you show there?
A. The average for -- if you left the two out, the average cost of capital would be -- instead of 12.83, it would drop to 11.85. The median would drop from 12.51 to 12.4. So your median would drop

about 11 basis point. So, yes, it's a slightly lower number. Not a lot, but it's slightly lower.
Q. I'd like to have you turn to page 7 of Schedule 2, Exhibit JSG-2. Do we find again that Keyspan and Laclede generate by far the highest rates of return?
A. Laclede does. The Keyspan depends on your definition of "by far," but, yes, it is about 80 basis point higher than the next one.
Q. Now, I'd like to turn to your primary DCF analysis. A discussion of that begins on page 20 of your testimony.
COMMISSIONER WEFALD: Which testimony is that -- the original testimony?
MR. BINEK: That's the original.
Q. (MR. BINEK CONTINUING) The growth rate that you use for this analysis as a range --
A. Could I ask you to wait for a moment?
Q. Sure.
A. Okay. Where was it that you were going?
Q. Okay. Page 20.
A. I'm there.
Q. Okay. The growth rate that you use for this analysis is a range, isn't it?
A. Yes.

Q. That range is presented on lines 14 and 15 of page 21 as 6.75 percent to 7.75 percent; is that correct?

A. Yes.

Q. How did you arrive at that range?

A. I considered a variety of factors. I believe that natural gas is going to tend to become a more important fuel source in the future, at least in some places. I also looked at the data that you pointed me to earlier. If you go to Schedule 2 of Exhibit JSG-2 and page 4 of that schedule -- I'm sorry -- page 5 of that schedule at the back, when you put the -- when you just look at the Zacks data, you'll see that companies with projected growth rates above 7 percent or 7 percent above include every single company there, except WGL Resources. So the 7 percent number is towards the middle of that range, of the range that I adopted, 6.75 to 7.75. There's one company that's below that range. Keyspan is just slightly above that range. Laclede's well above the range, but everybody else is grouped right in the middle. They're all in the 7 percent range. I thought that that was a pretty good anchor.

The retention growth I usually think of as

being a base amount that a company can achieve and usually under most circumstances you would expect it to be able to do better than that. And the analysts in this case thought that the company should do better than that, but if you look at the weighted average in the last column, you'll see that you have several companies a little under that range. And, let's see, Keyspan at 7.5 and Laclede at 9.4. So I used -- essentially, after considering other factors other than the simple two-thirds/one-third objective approach, I felt that 6.75 to 7.75 really reflected what investors expected and you can see that from the Zacks forecast where virtually all of my companies are 7 percent or higher.

Q. Okay. Looking at the top range of 7.75 percent, can you show me anywhere on pages 5, 6, and 7 of Schedule 2 where you have developed an average growth for the six companies that is as high as 7.75?

A. Now, the purpose of a range is to more or less put the company within some range around which you think on a normal basis these companies would be. The Zacks 7.6 percent obviously is well above the midpoint of that range. I was trying to establish about a 100 basis point range that would

be reflective overall of the group. So 7.6 would be well above the average in that range and the average for the weighted average would be toward the lower end of the range, but falls within the range.

So using those two numbers as anchors, you can go a little above 7.6 percent on the Zacks average earnings and get to 7.75. You can go a little below the 6.9 percent average and get to 6.75 and that gave me a 100 basis point range.

Q. Again, looking -- I'll repeat the question and please answer the question. Looking at the top of the range, 7.75 percent, can you show me anywhere on these pages, 5, 6, and 7, where you developed an average growth for the six companies that is as high as 7.75 percent? Just yes or no.

A. There's no simple average that does that, no.

Q. Okay. At lines 19 through 21 of page 21 you state that your range of 6.67 percent to 7.75 percent is consistent with the retention growth for the six companies. Please turn to page 5 of Schedule 2 and read to me the average retention growth for the six companies.

A. Would you take me back to the first citation that you had?

Q. Page 5.

A. You were citing someplace --

MR. HOBERG: Page 21.

Q. (MR. BINEK CONTINUING) Pages 19 through 21.

MR. HOBERG: Wasn't it line 19 through 21?

Q. (MR. BINEK CONTINUING) Lines 19 through 21 of page 21. The average retention growth rate for the six companies.

COMMISSIONER WEFALD: Does it start out "in my opinion," is that the line?

THE WITNESS: Okay. I see what you are asking. Page 21, the last three lines.

Q. (MR. BINEK CONTINUING) Starting at line 13 is the beginning of the paragraph.

A. But I believe you asked the question about the last sentence?

Q. Right.

A. And the last sentence says that, "This growth rate range is also consistent with the retention growth rates projected for these companies and their ability to grow by means other than retained earnings," which is what I was talking about earlier, that typically companies have the ability to grow by other means than retained

earnings and that allows them to generally achieve a slightly higher or somewhat higher growth rate than solely with book value growths.

You then asked me to turn to page 5 of Schedule 2 of Exhibit JSG-2 and reconcile the 5.5 percent average shown there with what I said on page 21. And the reconciliation is quite simply that it's -- if a company can have a base growth rate of about 5.5 percent, but investment analysts are projecting an average of 7.6 percent, it's consistent to think that 6.75 to 7.75 is consistent with the idea that book value forms sort of a base and the other methods that they can grow by, including investing in an unregulated operation, comes up with a higher rate of return.

Q. Over the long run how does a utility company do better than the retention growth?

A. There are several ways they can do that. One actually is contained in Mr. King's testimony. Mr. King has a growth rate component -- he calls it SV, issuing stock at above book value. If a company has some unregulated operations and those are doing reasonably well, it will have a book value -- or market value above book value and it's able to grow in that way. I believe Mr. King for his companies

estimated about 1 percent additional kicker to the growth rate from that. I'd have to go back and check his numbers, but it's something in that ballpark.

Another way that they can do that is by essentially borrowing to invest in new assets, that if those assets earn more than the cost of capital, it increases -- the market value of those assets exceed the book value and the company over time can generate retained earnings from these new unregulated assets and essentially build their equity ratio back up again and then repeat the process. And that's a very, very common thing, is that companies borrow because they find that they have a really good investment that will make them better off. They do so, they invest in it, and if it pays off well and it's making a 20-percent rate of return, and they borrowed the money at 8 percent, they get a big kick in their earnings per share. The stockholders get the difference between the 20 percent the operation makes and the 8 percent that they borrowed at.

So those are a few of the ways and I think those are probably the primary ways. I could probably think of a few others that are less

important, but those are big ones. And my 5.5 percent earnings retention growth rate, I should note, is a little bit different from Mr. King's book value growth rate in that I have not included the SV factor in the 5.5. I have assumed that the SV factor -- or actually I should call it a term because it's used as a term, it's an add-on to the retention growth rate -- is encompassed in the Zacks earnings forecast, which are higher, and that the other ways that a company can grow, including the SV term, are in the Zacks earnings growth estimate. So retention growth is sort of a baseline, but you can do all these other things. And clearly investors are expecting some of that to happen.

MR. HOBERG: Dr. Gaske, for the record, what is the SV factor?

THE WITNESS: It's the stock -- the percentage increases in the shares outstanding times the premium over book value that you are able to sell your stock at.

MR. HOBERG: Thank you.

THE WITNESS: And explained in fairly great detail in Mr. King's testimony.

(Exhibit 12 was marked for identification.)

Q. (MR. BINEK CONTINUING) I'd like to refer

you to page 23 of your testimony. On pages 6 through 8 you describe data by Ibbotson Associates on returns to stocks, bonds and treasury bills since 1926. I've handed you a response that Mr. King filed to MDU's September 6, 2002 data request, question 14. And this is marked as Exhibit 12.

Have you seen this response?

A. Yes, I have.

Q. In this response does Mr. King represent that he has supplied the yearly returns to an S&P composite index and S&P utility index, long-term corporate bonds and public utility bonds for every year from 1927 to 2001?

A. Yes.

MR. HOBERG: Isn't it 1928?

MR. BINEK: Or '28.

Q. (MR. BINEK CONTINUING) Now, would you look at the bottom of that sheet and identify what is reported on the last four lines?

A. A geometric mean return for the series and an arithmetic mean return for the series, a standard deviation, and a median.

Q. Are you familiar with those terms?

A. Yes, I am.

Q. Would you please describe your

understanding of the meaning of each of those terms?

A. The geometric mean tells you the average historical rate of return that occurred throughout the period, assuming compounding. And it's a very good indicator of your past historical return that you earned. The arithmetic mean is the average of the return earned each year, year by year. And it's a very good indicator of future expected return.

The standard deviation tells you how much variation there is in a particular series of numbers. And, in fact, what the standard deviation really tells you is that if you assume that the data have what is referred to in statistics as a normal distribution, it's a number that you can add to the mean, the arithmetic mean, plus or minus, to determine a range within which two-thirds of the observations fall or would be expected to fall. In this case I'm not entirely sure whether he had done this as a population mean or sample mean. Usually it's calculated as a sample mean, so I would presume that, but maybe we'd have to ask him which kind of mean he used or rather what kind of standard deviation he used.

And the last number, the median, is the number that half of the observations are above and

half are below.

Q. If the standard deviation is higher than the mean, what does that tell you about the statistical significance of the mean?

A. That there's a high probability that the mean of that particular series is zero, or at least -- let's say the standard deviation is exactly equal to the mean, then there's about a 16 percent chance that the real number would be zero or less.

Q. Please read the arithmetic means and the standard deviations of each of these series.

MR. HOBERG: I think we better have this thing offered first, Mr. Binek.

MR. BINEK: Oh, I'm sorry. I will offer.

MR. HOBERG: Any objection to Exhibit 12, Mr. Pearce?

MR. PEARCE: No. On the assumption that Mr. King prepared this from published data, I have no objection.

MR. HOBERG: Exhibit 12 is admitted. Mr. Binek, please.

Q. (MR. BINEK CONTINUING) Now, would you please read the arithmetic means and the standard deviations of each of these series?

A. 12.33 percent for the S&P composite, and

20.3 for the standard deviation. For the public utility index, 11.11 percent. And 22.65 percent for the standard deviation. The long-term corporate bonds, 6.06 percent, and the standard deviation, 8.76 percent. The public utility bonds, 5.79 percent. The standard deviation, 8.11 percent.

Q. If I buy a share in a company, what price do I pay, the market price of the share or the book value of the share?

A. You pay the market price.

Q. If the market price is twice the book value, I still have to pay the market price, don't I?

A. Yes, you do.

Q. If the company is earning 20 percent on its book value and I pay a market price twice that book value, what is my return?

A. I can't calculate that in my head.

Q. Would it be 10 percent?

A. If there's no growth. Yes, if the company paid out its dividend, everything they make.

Q. What, in general, do you believe to be the relationship between market price and book value of the average company in The Value Line Investment Survey that you cite on page 25 of your testimony?

A. It's quite above book value. I don't recall the composites at this time, but it's probably in the neighborhood of four or five.

Q. Please turn to page 9 of Schedule 2 of your Exhibit JSG-2. We keep going back to that sucker.

COMMISSIONER WEFALD: Would you repeat the number again, please?

MR. BINEK: It's JSG-2, Schedule 2, page 9.

THE WITNESS: Which page now? I'm sorry.

Q. (MR. BINEK CONTINUING) Page 9. There you show debt and equity -- are you there? I'm sorry.

A. Yes, I am.

Q. There you show debt and equity ratios of your six proxy companies. They are all quite close together except one. Which is that one?

A. Keyspan.

Q. Keyspan has an equity ratio of only 38.84 percent. What effect would that have on the financial risk of that company?

A. Other things being equal, that should raise what we referred to as the financial risk. And Keyspan, if you look at page 2 of the same schedule, has an A plus and an A2 bond rating, which gives you a good idea of how investors view the financial risk. It's pretty comparable. Actually, it's the

only one that's identical to the first mortgage bonds of Montana-Dakota -- or MDU Resources that are secured by the public utility assets. So Montana-Dakota -- Montana-Dakota's bonds and Keyspan bonds have virtually the same rating so that the overall risk, that at least bond investors are looking at, is pretty much identical between the two.

Q. On page 7 of Schedule 2, doesn't that show that Keyspan has the second highest DCF return of the six companies?

A. Yes.

Q. Do you think that the low equity ratio of Keyspan might have some influence on the equity risk perceived by investors?

A. Well, two things interrelate in the sense that you can't -- when you look at the return on equity, you have to look at both the business risk of the company and its financial risk. And the two, in a sense, multiply against each other. So undoubtedly part of their rate of return is based on their high financial risk or -- and part of it is based on business risk. When you combine the two things, you come up with an overall risk assessment and, as I said, the bond rating agencies look at Keyspan as a whole as being almost identical to the

Montana-Dakota public utility assets. But both of them are rated -- have bond ratings below the average for that group, so I'm not surprised that Keyspan is above the average. Montana-Dakota Utilities do have low average bond rates for this group.

Q. I'd like to have you turn to page 32. On page 32 you list your costs of capital indications. What is the distinction between investor requirement and cost of capital?

A. The investor requirement is the return investors require on the sunk investment that's there. The cost of capital is what they require in order to be able to track new capital on reasonable terms.

Q. If we ignore flotation costs, we would focus on the first column; is that correct?

A. Yes.

Q. Now, I'd like to concentrate on the second stage retention growth. The number we see there was developed on page 6 of Schedule 2 of your exhibit; is that correct?

A. That's correct, yes.

Q. The growth component of that number was developed on page 5 of Schedule 2; is that also

correct?

A. Yes.

Q. Isn't it true that the retention growth that you used is not all retention growth, but only one-third retention growth, the other two-thirds being Zacks forecast?

A. Right, that's why I referred to it as a second stage retention growth, or it's a weighted average of Zacks and retention.

Q. If we developed a DCF using solely retention growth, would it consist of a growth factor of 5.5 shown on page 4 of Schedule 2 and a dividend yield of 5.14 percent developed on page 3 of Schedule 2?

A. Mathematically that would be correct. It wouldn't mean anything because it wouldn't match up with investors' expectations.

Q. What would the DCF result be?

A. If you add 5.5 and 5.14, you get 10.64 and then, obviously, you would add the flotation cost adjustment.

Q. Okay. Thank you.

MR. BINEK: Can I take a moment, please?

MR. HOBERG: Yes.

(Exhibit 13 was marked for identification.)

COMMISSIONER WEFALD: What number is this exhibit?

MR. HOBERG: Exhibit 13.

Q. (MR. BINEK CONTINUING) Mr. Gaske, does this -- I've handed you what has been marked as Exhibit 13. Do you recognize that exhibit?

A. It appears to be an exhibit you showed me earlier this year. I'm not positive it's the same one, but it looks to be almost identical.

Q. And you see a reference of Exhibit 14 in the right-hand corner of that exhibit and below that a Docket No. 80 under case PU-399-01-186?

A. Yes, I do.

Q. Was that an MDU electric rate case?

A. Yes.

Q. And this was a document that was introduced in that case; is that correct?

A. Yes.

Q. Can you tell me what this document is?

A. It looks to be a survey of rates of return that have been authorized -- or requested and authorized in past rate proceedings. It also shows the dollar amount that the increase or decrease and other information about when these cases occurred.

Q. Okay. And would you agree that -- I'm

referring to the first page of this document in the introduction, that it says that the survey covers orders issued by state regulatory commissions during the period October 1, 2001 through September 30th, 2001; is that correct?

A. I'm sorry. I missed where you were referring.

Q. It's in the first paragraph, about the third or fourth line down, it says that -- it indicates the period covered by the report is October 1, 2000 through September 30th, 2001?

A. Yes.

Q. Okay. And what is the date of this report?

A. It's dated December 15th, 2001.

Q. And it says that it's an annual survey?

A. Yes.

Q. So would it be safe to assume that this is the latest annual survey that has been put out by Public Utilities Reports?

A. That I don't know.

Q. Just assuming an annual survey issued December 15th of 2001.

A. Yeah, I would assume so. I don't know if it's some kind of a mutant average or something like that.

Q. Okay. But there's no exact science to this exhibit as far as use of it, but I'd like to explain to you, if you would look at the following pages, I've highlighted several cases and if you will look at those cases, they are all ones that were decided in the year 2001. I would also like to point out that under North Dakota, Roman numeral VII, in red highlight or red marker is Otter Tail Power Company Gas at 12 percent ROE, and I would ask that all of the parties acknowledge the fact that Otter Tail Power Company does not have a gas distribution company operating in North Dakota and so this is obviously an error. It's just a carryover from their electric case and the same reference is to their electric case, is just a mistake that they made. There are not all that many cases here. I'd like to have you start with the first case.

MR. BINEK: Yes. I was just getting to that. I would like to offer Exhibit 13.

MR. HOBERG: Any objection, Mr. Pearce?

MR. PEARCE: No. It's hearsay, but probably pretty reliable hearsay, so I won't object.

MR. HOBERG: Exhibit 13 is admitted.

Q. (MR. BINEK CONTINUING) Now, I would ask, would you please go through the highlighted cases

and just indicate for us the company name, the order date and the newly authorized rate of return on company equity, starting with Arizona, first of all?

MR. HOBERG: You want him to read these into the record?

MR. BINEK: He can or --

MR. HOBERG: Can't the document speak for itself?

MR. BINEK: That's fine. I have no problem with that.

Q. (MR. BINEK CONTINUING) I would like to have you just kind of peruse these different entries, though, and then I would -- the question I would have for you is, if you would agree with me that the ROE range for the majority of these cases range from 10.7 percent to 11.5 percent?

MR. HOBERG: Do you need a couple minutes to look at that, Dr. Gaske, or a couple seconds?

THE WITNESS: I don't see any that are below 11.7 -- or I'm sorry. I don't see any that are below 10.7. I do see a couple that are 12.25 and 12.1 on the last page.

Q. (MR. BINEK CONTINUING) But my question is, would you agree that the majority of the cases range from 10.7 to 11.5?

A. Well, if you start at the very bottom of the range and count upwards until you get to a majority, that's probably true. If you start at the top and work your way down, you probably get another number.

Q. Okay. Well, would you agree with this statement, that the majority of them range from 11 to 11 and a half percent? If you can't agree, that's fine. The document does speak for itself.

A. I only see five back in that time period were above 11.5.

Q. Okay. And there were several below 11?

A. Yes.

Q. Okay. Would you also agree with me that, according to this report, the highest ROE given in 2001 that was included in the survey was 12.25 percent?

A. Yes.

Q. Would you agree that there have been relatively few gas rate cases reported so far in 2002, reported by Public Utility Reports, if you know?

A. I don't know.

Q. Okay. Are you familiar with a case entitled Re Yankee Gas Services Company, a case

decided by the Connecticut Department of Public Utility Control on January 30th, 2002 and reported at 215 PUR4th, 185?

A. No, I'm not.

MR. BINEK: At this point, I would just like to show a copy of the case. I don't believe it needs to be offered as an exhibit, unless MDU would like to have it as an exhibit. It just refers to the ROE in this particular case, and I would like to have Mr. Gaske look at it.

MR. PEARCE: Well, I certainly would object to it being offered as an exhibit. I don't think that the rate of return on a case last year in the Eastern Seaboard has any relevance whatsoever to the return and costs in this case. So it certainly isn't relevant to this proceeding.

MR. BINEK: The only purpose is to show what is happening from basically the end of 2001 in the PUR report, what is shown up in PUR since then, kind of showing a trend.

MR. PEARCE: Well, that's the issue. Why would that be relevant to this case?

MR. BINEK: I think it is relevant.

MR. HOBERG: Dr. Gaske said he's not familiar with that case. Is there a better witness

to offer this through?

MR. BINEK: No, I don't think so. It's a case that's been reported and it's not a big issue.

MR. HOBERG: Are you withdrawing?

MR. BINEK: Well, my first question is whether the Commission would like to have it offered as an exhibit? I have three cases. I'll offer them as exhibits and if that's the course you would like to pursue and, apparently, based on the objections that Mr. Pearce has indicated, that would be the way to go.

MR. HOBERG: Okay. So you have two more besides this one?

MR. BINEK: Two more cases, yes.

MR. HOBERG: Are they the same relevancy that you're proposing?

MR. BINEK: Right. They're different -- in different jurisdictions. They're cases that have been reported in the year 2002.

MR. HOBERG: Mr. Pearce?

MR. PEARCE: Well, I would object to any such case. I mean, if they're cases reported in some public forum, anybody can look at them, but they certainly have no relevance that I can see to the issues in this case.

MR. HOBERG: Why don't you state them, give us the cites of those on the record, please, Mr. Binek, and we can make them available on an official notice basis, if the Commission wishes to use them, if the Commission believes they're relevant.

MR. BINEK: That's fine with me.

MR. HOBERG: Give Mr. Pearce a copy and perhaps after he has a copy of those, he will be able to make some argument that the Commission shouldn't take official notice of those because they're not relevant. At this point in time, you know, I don't know what the Commission would do with those. Maybe nothing. So let's take official notice of those three and pass them out to the Commission as a possibility that the Commission may take official notice of those in actually making a decision.

MR. BINEK: Very good.

MR. HOBERG: Why don't you read each of them as you're passing them out, what the decision is?

MR. BINEK: The first case is entitled Re Yankee Gas Services Company. It's Docket No. 01-05-19PH01, decided by the Connecticut Department

of Public Utility Control on January 30, 2002. And that is reported in Public Utility Reports 215 PUR4th, 185.

The next case is Re Berkshire, B-e-r-k-s-h-i-r-e, Gas Company. It's Docket D.T.E. 01-56, decided by the Massachusetts Department of Telecommunications and Energy, on January 31, 2002. And pages are eliminated at the bottom. That case is in 215 PUR4th, that's P-U-R, 361.

And the last case is a short one. Re Atlanta Gas Light Company, Docket No. 14311-U, decided by the Georgia Public Service Commission on April 29th, 2002. And that is reported in 217 PUR4th, page 190.

MR. HOBERG: Mr. Binek, you're not offering these for any of the facts contained therein, just for the rulings in these matters?

MR. BINEK: The only purpose for these cases is to show the return on equity that has been authorized by these other public utility commissions.

MR. HOBERG: As part of their orders in those cases?

MR. BINEK: Pardon?

MR. HOBERG: As part of their orders in

those cases?
MR. BINEK: Yes.
MR. HOBERG: Mr. Pearce?
MR. PEARCE: Well, I just want to make sure that my objection stands as to any conceivable relevance of these. He is simply taking three decisions from other jurisdictions based on totally different facts and circumstances. I would hope the Commission would not -- I'm sure they do not simply come to their decision by copying the results from other unrelated cases, so I don't think it will have any undue influence, but certainly it has no conceivable bearing on this case. We don't even know if these are all the decisions from that year. Even if they were, they certainly wouldn't be relevant.
MR. HOBERG: Thank you, Mr. Pearce.
Okay. Mr. Binek, do you have any further questions of Dr. Gaske?
Q. (MR. BINEK CONTINUING) I'd like to focus on some areas where you apparently agree with Mr. King. And this basically is in your rebuttal testimony, I believe.
MR. BINEK: That testimony hasn't been marked yet, has it?

MR. PEARCE: I didn't realize you were asking from rebuttal testimony. That isn't in the record, so we have to wait.
MR. BINEK: Okay. We'll wait. We'll cover it afterwards.
MR. HOBERG: You're bringing Dr. Gaske back on as rebuttal?
MR. PEARCE: Yes.
MR. BINEK: Okay. In the past we've kind of run these altogether. So that's fine. We'll cover him after he gives his rebuttal.
MR. HOBERG: I think that will be better. It will follow more clearly.
MR. BINEK: I have no further questions then.
MR. HOBERG: Thank you, Mr. Binek.
Commissioner Reinbold, did you have any questions of Dr. Gaske?
COMMISSIONER REINBOLD: Not at this time. Thank you.
MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.
COMMISSIONER WEFALD: None at this time, either.
MR. HOBERG: Thank you. Commissioner

Clark, please.
COMMISSIONER CLARK: I did have a couple.

EXAMINATION

BY COMMISSIONER CLARK:

Q. On page 28 of your testimony --
COMMISSIONER REINBOLD: What page?
COMMISSIONER CLARK: Page 28, lines 18 and 19.
Q. (COMMISSIONER CLARK CONTINUING) In this section you are discussing some of the business risks that you feel are faced by MDU.
A. Yes.
Q. You make a statement -- this follows up on previous testimony earlier this morning talking about the direct competition from propane heating oil. I think coal was used as another example of competition that MDU faces. Wouldn't raising rates be a strange action in response to direct competition?
A. Definitely not, under the circumstances. If you have direct competition, you will lose business, if it's really powerful direct competition. Currently, Montana-Dakota is able to maintain its business. If it has to maintain its rates at a level that it can't recover its costs, it

actually should try to go out of business and let the competitors have the business. So in a very short- run context, usually in markets you see that if there's a lot of competition, people are forced to lower their rates and the one who lowers his rates far enough that he can't recover his costs anymore, he goes out of business.
In Montana-Dakota's case I don't think that the competition at this point in time is so severe that they would go out of business, but if they were not allowed by this Commission to charge rates that would recover their costs, they should think about getting out of the business. Just as in a competitive market, if competition is the regulator that forces the rates to be below cost, a competitive company would after some time exit the market.
Q. Well, I'm asking because it seems counterintuitive that if you're facing competition and you've got potentially some customers who are on the edge, could potentially switch to another, in this case, heating source, that an increase in the rates would cause potentially some of those customers to switch over, and wouldn't that in the end, in fact, just increase the risk that MDU faces?

Wouldn't the better response be to find savings somewhere else, if you are, in fact, facing that competition?

A. Well, I think as Mr. Fox testified earlier, they have tried to find as many savings as possible. What really happens with natural gas is that the cost of the commodity drives the attractiveness to a great deal -- great extent, also. So that's probably a bigger problem for Montana-Dakota in terms of whether they increase the distribution charge by 4 percent or whether the suppliers to the company, whether the natural gas markets are selling gas at $2 or whether it's at $4. That's where they really have to be concerned about such competition. And right now they can compete. If the price of natural gas is driven upwards in the $4- and $5-range, you may see people shutting off their gas service at a fairly rapid rate.

Q. Another question on that same page, talking about kind of the general business climate and risks that MDU faces. On lines 10 through 12 there's a sentence there, On a practical level, MDU's relatively small natural gas distribution operations are heavily dependent on a relatively undiversified local economy.

Could you just expound on that a little bit?

A. Well, you have in their service territory some mining operations, refining operations, a lot of farming and farming-related operations, and they face some risk that some of these kind of operations, manufacturing-type things -- I shouldn't call it manufacturing, but processing foods and things like that, could shut down and they'd lose that business, but, to my mind, a much bigger risk for them is the fact that if operations like that shut down around here, the people who work at those plants and local economies will suffer and people will migrate out of the towns and Montana-Dakota will be sitting there with gas distribution mains in place and yet because of, you know, events in the local economy, they're at risk.

And people who serve larger cities have a much smaller risk in that regard. Most large cities have many, many different kinds of businesses and industries that support the population and when one leaves, usually others are able to expand to take up the slack. I don't see that in the towns that Montana-Dakota serves.

Q. I guess I've -- the reason I ask is, I've

always heard that North Dakota's economy, which would be true of economies of states like ours, is typically more resistant to booms and peaks and valleys. That, in fact, larger states more kind of dynamic economies are much more likely to have the peaks and valleys. And that's what we've seen certainly in this latest recession. We seem to be a little bit more recession proof. We seem to be a little bit less prone to the booms when times are good as well.

How does that fit with the comments in there?

A. As far as short-run booms and busts, I think you probably are pretty insulated from that because of a lot of agricultural-related things, but agriculture booms and busts a little bit. To the extent more energy production occurs in the state, you'll probably be more subject to booms and busts in the energy business.

On a longer-term basis, and Montana-Dakota has to think about longer-term basis, their plant is there for many, many years. They put it in and it will stay there for 30 years or something like that. As businesses shut down and people migrate out of towns, or just the natural change of people's desire

to, say, move to the big cities or whatnot, they can leave the towns, but Montana-Dakota's facilities are still there. They still have to try to recover their costs. To the extent you get some major employers that shut down for whatever reason, it's not a guarantee that the people will stay here or that the people will be able to pay their bills or things like that.

So even if you're resistant to short run year-to-year fluctuations in boom and bust cycles or even on two- or three-year cycles, on a longer run cycle, which really is very important to MDU because it has a lot of fixed costs, they have to worry about the big employers in this area, will they shut down and really dramatically change the economics of their business.

COMMISSIONER CLARK: That's all I have right now. Thank you.

MR. HOBERG: Thank you, Commissioner Clark.

Mr. Pearce, any further questions of Dr. Gaske?

MR. PEARCE: Just one short question, really.

REDIRECT EXAMINATION

BY MR. PEARCE:

Q. Dr. Gaske, there was some discussion on your cross-examination about Exhibit 13, which was a PUR report of decisions ending at a point in 2001. Would it surprise you that the cost of equity capital that you derived for Montana-Dakota for the 2003 projected year would be different from and perhaps more than any of the cases which the last report here seems to end in June of 2001 in this Exhibit 13?

A. No. No. In the last year the stock market has gone down considerably in general. Investors' risk aversions have increased and we've seen some fairly remarkable things happen in the financial markets and not all of them very good for investors.

Q. And the cost of capital is essentially unique to each entity, isn't it, depending on the circumstances and the business and the risk, and so on?

A. Yes.

MR. PEARCE: I have nothing else.

MR. HOBERG: Thank you, Mr. Pearce.

Mr. Binek, anything further of Dr. Gaske?

MR. BINEK: No.

MR. HOBERG: Thank you. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. I just have a question about this risk aversion factor. I can only relate it to my own experiences in the market and --

A. I hope they've been good.

Q. Haven't -- just describe for me this risk aversion factor.

A. Well, one of the things that has happened quite a bit during the last year is that people have been selling off stocks or they really don't want to own common stocks. And they are trying to own short-term investments, things like U.S. Treasury bills, or cash or CDs even though -- and as a result of that, they have driven the short-term interest rates way down. They want to get out of stocks. They want to put their money in the safest place that they can.

And what happens there is that the interest rates on your CD at the bank and/or U.S. Treasury bills or even U.S. Treasury bonds have gone way down. Whereas, in my opinion, the required return on things like common equities has gone way up.

People just don't want to be in equities right now.

Q. That's the part I don't understand. Why would that go up? Why would it just be a certain amount greater than what you can get on a short-term money note, let's say? I mean, I don't understand your conclusion that that would go way up, if I'm only able to return -- get a return of a very small amount on a very short-term equity. Why wouldn't I be pleased if it was 5 percent more, and I could know that it's going to be even 5 percent more, let's say 8 percent rather than 3 percent, or I guess even right now many times in money market it's 1 percent? So why wouldn't I be pleased if I could get 6 percent?

A. The overall return might go up or it might go down some that you require on your common equities, but they won't go down nearly as much as on safer investments. But investors view the market as very risky. If you say -- you think of it in terms of a common equity has five units more risk than a bond, if the market is very risky, that extra five units of risk will be very valuable. If people are very uncertain about the market, they don't -- they're going to want a very high return to take the five units of extra risk.

If the economy is doing very well, things are very stable and people are very confident about the future, the price of risk, what they're willing to spend for -- or what they require for that extra five units of risk will be much lower. So you ask, you know, why don't they want 5 percent more than what they can get on bonds? Over time what they require will go up, the extra amount they require will go up and down. Right now we're in a period where people don't want to own common stocks. They think they're too risky and they do want to own bonds and short-term government bonds and short-term debt.

So the extra units of risk, let's say the five extra units of risk, those become very valuable or very expensive, they just aren't going to buy unless they think they are going to get a very good premium over what they can get on the bonds. So the premiums go up and down over time.

COMMISSIONER WEFALD: Thank you for that analysis.

THE WITNESS: Hopefully, your experiences have been better than mine in the market, but it has been a risky year or a very discouraging year.

MR. HOBERG: Thank you. Commissioner

Clark.

FURTHER EXAMINATION

BY COMMISSIONER CLARK:

Q. I do have a question on that. Is it that investors want to get out of the stock market, period, or does it require maybe a little bit more granular analysis, and that is that certain sectors are just horrendous? For instance, telecom is one of them. Fortunately, we can't invest in the telecom market because we are prevented by state law from doing that. Are certain stocks more attractive because of that, for example, potentially kind of old-fashioned utility companies that are regulated?

A. The utility companies are probably more attractive, much more attractive now than, say, a telecom stock. A lot of people wanted to buy telecom stocks two years ago. But relative to bonds, utilities are less attractive, so the premium that people require on utilities is, I think, higher now and has gone up over the last year. So some people selling telecom will buy utilities. Some people who have utilities will sell the utilities and buy bonds. But if you look at bonds versus utilities, I think that spread is increased. Utilities versus telecom, that spread has really

increased. Nobody wants the telecom stock right now. So all across the board, from the very safest to the very riskiest investment, I think everything is spread out.

Q. Would it follow then when the stock market get on a roll like it did for the past 10 years or so prior to the last few we've had, that utility regulated ROEs should go down then because it's easier to attract capital?

A. The spreads over bond yields should go down, but you can have a very good market, but the interest rates are very high. You can -- so it really depends on a lot more factors.

Q. I'm just wondering if then the argument would be, well, all the peer companies are doing so well, we need to increase our rate of return now to attract capital vis-a-vis the rest of the market?

A. Well, that one depends on -- yeah, how much the individual companies are willing to invest. But it really is a good question about -- people are afraid to invest in almost anything. So the measure, at least that I try to look at is, what kind of spread versus the bond yield, because those are much easier to determine than the equity returns.

COMMISSIONER CLARK: That's all I have. Thanks.

MR. HOBERG: Thank you. Any further questions of Dr. Gaske? Thank you, Dr. Gaske. Take an hour recess here, luncheon recess?

COMMISSIONER WEFALD: Can you tell me, please, the order of witnesses that are going to be followed for this average?

MR. HOBERG: I believe they're in exactly the same order as listed in the direct testimony, is that correct, Mr. Pearce?

MR. PEARCE: Yes, it is.

COMMISSIONER WEFALD: And then we'll go through and then the rebuttal will happen in the same order by those people following?

MR. HOBERG: Then it will be Mr. Binek's presentation of his witnesses after the direct of MDU and then followed by the rebuttal.

COMMISSIONER WEFALD: That's a little unusual, but -- because then what happens you have -- well --

MR. HOBERG: I don't think it's unusual. I think that's the practice we followed in the past.

COMMISSIONER WEFALD: But the thing is, there's a lot of information that has been agreed

upon by the parties by the time we get to the rebuttal. So we're going to have to cover things that perhaps aren't that important because the case -- they have agreed on a bunch of things as they have gone along.

MR. HOBERG: Well, I would assume those things we've agreed upon you're not going to be spending much time on, correct?

MR. PEARCE: No. The rebuttal only touches on points on which there's disagreement still. So the rebuttal -- anything that's been agreed to won't be testified to on rebuttal.

COMMISSIONER WEFALD: Okay.

MR. HOBERG: Is that the order you expected, Mr. Binek?

MR. BINEK: Well, we have done both ways where we've gone with questioning on both the direct and rebuttal testimony initially, and that was what -- kind of the mode I was in. It doesn't matter to me which way we do it, and this seems to be set up to do it the long way.

MR. HOBERG: The long way? I don't know that it's necessarily longer, as long as the parties understand that things that, you know, there's no disagreement about, you don't have to spend any time

on really.
MR. BINEK: Hopefully, it will work out that way.
MR. HOBERG: I think it's sort of six of one and half-dozen of the other, unless you --
MR. BINEK: It's fine to do it that way.
MR. HOBERG: Perhaps we'll reflect on that over the break.
MR. PEARCE: It seemed like it was the usual judicial procedure; plaintiff, defendant, and then plaintiff's redirect, is really the mode we are following, I think.
MR. HOBERG: That's what I thought, too. All right. Let's take a one-hour lunch.
(Lunch recess was taken.)
MR. HOBERG: Okay. We're back on the record after a luncheon recess. And just to kind of rehash maybe the concerns about the procedure today in regard to direct and rebuttal, I think everybody is basically pulling in the same direction and maybe to provide a little bit of consistency and some guidance, it seems like except for perhaps the first witness, Mr. Fox, who you wanted to highlight the direct especially, you're offering the direct, but you're not really asking many questions.

MR. PEARCE: Right.
MR. HOBERG: And maybe that will be the procedure for the whole rest of the direct. It can go relatively quickly, except for the PSC's case, but if you do really have -- if your questions are more along the lines of something for the rebuttal, perhaps you should save them for that, but there may be some questions to highlight or to ask something that somebody neglected to cover in the rebuttal, but, basically, I think the direct should go relatively quickly, at least for MDU's case, and the rebuttal will be where more of the questions are, but I think we'll get to the same place we would have if we had just forgot about the direct and went right to the rebuttal. I think that was a time where there was pretty much agreement in another case where we could just move right to the rebuttal, but that isn't the situation here, as I read it, anyway.
So we'll proceed with the direct and then perhaps move relatively quickly to the rebuttal, except for perhaps Mr. Binek's case. Is that clear? I maybe didn't make it very clear. I hope I did.
Mr. Pearce, do you want to proceed, please?
MR. PEARCE: Yes. I'll call Craig Keller.

MR. HOBERG: Mr. Keller, were you here earlier when I gave the admonition in regard to perjury?
THE WITNESS: Yes.
MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.
THE WITNESS: Yes, I do.
MR. HOBERG: Thank you. Mr. Pearce, please.

CRAIG A. KELLER,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Keller, in connection with this case have you prepared or had prepared under your direction and control direct testimony of Craig A. Keller, CPA?
A. Yes, I have.
Q. And if I were to ask you the questions that are in that prepared, prefiled testimony today, would your answers be the same as appear in there?
A. Yes, they would be.
Q. And to the best of your information and

belief, all of your answers contain accurate and correct information?
A. Yes, they do.
MR. PEARCE: I will offer the direct testimony of Mr. Keller. I think it would be Exhibit 14.
MR. HOBERG: Exhibit 5.
MR. PEARCE: I'm sorry. Exhibit 5. I have no further direct questions.
MR. HOBERG: Thank you, Mr. Pearce. Any objections to Exhibit 5?
MR. BINEK: No.
MR. HOBERG: Exhibit 5 is admitted.
Mr. Binek, do you have any questions of Mr. Keller on direct?
MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Keller, would you please turn to your Statement A?
COMMISSIONER WEFALD: Where do we find that?
MR. PEARCE: Exhibit 2.
MR. HOBERG: There's a document entitled Statements A through O. Is that what you're

referring to, Mr. Binek?
MR. BINEK: Yes.
COMMISSIONER WEFALD: And this is Statement F?
MR. BINEK: Statement A.
Q. (MR. BINEK CONTINUING) The first two pages of Statement A present a balance sheet that is labeled MDU Utilities Co. The remaining 27 pages are of notes on the balance sheet; is that correct?
A. Yes.
Q. Those 27 pages are not headed MDU Utilities Co., but rather MDU Resources, Inc.; is that correct? Am I correct that the notes pertain to a different balance sheet than Statement A?
A. I believe the balance sheet is the -- the balance sheet of Montana-Dakota is not the consolidated balance sheet, whereas the statements would be the consolidated -- the statements that are in our consolidated balance sheet of MDU Resources Group.
Q. Do all the notes on pages 3 through 27 apply as well to the first two pages of Statement A?
A. They would apply to the Statement A. They may also apply to -- there will be information that will apply to some of the subsidiaries of MDU

Resources Group as well.
(Exhibit 14 was marked for identification.)
MR. BINEK: This will be Exhibit 14.
Q. (MR. BINEK CONTINUING) Now, I've handed you a document that's been marked as Exhibit 14. Can you identify that exhibit?
A. It says $150 million secured medium-term notes, MDU Resources Group, Inc.
Q. I'm sorry. Could you speak up a little bit?
A. It's the prospectus for $150 million secured medium-term notes, MDU Resources Group, Inc.
Q. Okay. And does this prospectus cover the $133.5 million in long-term debt that you list on page 1 of Statement F?
A. I believe it applies to a portion of that. I don't believe it applies to the entire. It would apply to the debt that was issued under this prospectus or under this here arrangement, financial instrument.
Q. Could you repeat your answer?
A. I said I believe it applies to the debt on this schedule of the $133 million that was issued under this financing instrument. So there is -- I believe there's also some debt that we have

outstanding that was not issued as part of this here prospectus here.
MR. BINEK: Okay. At this time I would offer Exhibit 14.
MR. HOBERG: Any objection to Exhibit 14?
MR. PEARCE: No.
MR. HOBERG: Exhibit 14 is admitted.
Q. (MR. BINEK CONTINUING) Who issued this prospectus?
A. MDU Resources Group, Inc.
Q. I'd like to have you turn to page 2 of the prospectus under the section titled "The Company." What company is described there?
A. It refers to the company as being MDU Resources Group, Inc.
Q. Does the company that -- the term "the company" include all subsidiaries under Centennial Energy Holdings?
A. I do not believe so. This states it's for the company's first mortgage bonds that are -- would be issued under our mortgage indenture, so that would apply only to MDU Resources and Montana-Dakota Utilities. It's on the first page, the very front of the prospectus, if you look on the very front of the prospectus. If you read the very first

sentence, it says, MDU Resources Group intends from time to time to offer up to $150 million aggregate principal amount of its secured medium-term notes as an additional series of the Company's first mortgage bonds having maturities ranging from 9 months to 35 years.
The only company that's able to issue notes under our mortgage indenture is Montana-Dakota Utilities or the utility.
Q. Lower down on that page of this, and I'm referring to page 3 now, is a section titled "Use of Proceeds." Would you please read that section?
A. "Unless otherwise set forth in a prospectus supplement, the net proceeds from the sale of the notes will be used to retire certain of the company's outstanding senior securities, including the refunding of outstanding first mortgage bonds, and for other general corporate purposes."
Q. Where in that section is there any specific reference to MDU Utilities Company or MDU Utilities Co.?
A. It doesn't state anything in this right here.
Q. Were those retired senior notes issued in the name of MDU Utilities Company or in the name of

the parent company, MDU Resources?
A. Well, they are one and the same. MDU is not a separate -- Montana-Dakota is not a separate corporation. So I believe all our debt is issued in the name of our legal entity, which would be MDU Resources Group, Inc.
Q. Where in this prospectus do we find a statement that the proceeds from the sale will be used only for MDU Utilities Company?
A. Well, I believe when it's saying -- refers to the company, it's talking about the company, MDU Resources Group, which is that legal entity only, and I think if we go down here --
MR. PEARCE: Could I just ask that we be careful for the record. I mean, there is no MDU Utilities Company. It's Montana-Dakota Utilities Company or MDU Resources Group, and I think we may be getting confused if we keep referring to MDU Utilities Company, which doesn't exist.
MR. HOBERG: Thank you, Mr. Pearce.
THE WITNESS: I guess when it refers to the company, it's talking about the legal entity, MDU Resources Group, and that is the same as Montana-Dakota. They're one legal entity. So when it refers to that, you know, I believe what it's

stating is that it is for the company, Montana-Dakota, MDU Resources Group, which is the same legal entity.
MR. BINEK: I have no further questions.
MR. HOBERG: Thank you, Mr. Binek.
Commissioner Reinbold, do you have any questions?
COMMISSIONER REINBOLD: No.
MR. HOBERG: Thank you. Commissioner Wefald?
COMMISSIONER WEFALD: I have none.
MR. HOBERG: Thank you. Commissioner Clark?
COMMISSIONER CLARK: None at this time. Thank you.
MR. HOBERG: Mr. Pearce, do you have any further questions of Mr. Keller?
MR. PEARCE: No.
MR. HOBERG: Thank you, Mr. Keller. Mr. Keller, do you have the exhibit that was handed to you that was marked? Thanks.
Your next witness, please, Mr. Pearce.
MR. PEARCE: I'll call Rita A. Mulkern.
MR. HOBERG: Ms. Mulkern, did you hear the admonition I gave earlier in regard to perjury?

THE WITNESS: Yes, I did.
MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.
THE WITNESS: I do.
MR. HOBERG: Mr. Pearce, please.

RITA A. MULKERN,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:
Q. Ms. Mulkern, did you prepare direct testimony and have it prefiled in this case?
A. Yes, I did.
Q. And if I were to ask you the same questions today, would your responses be the same as in that prefiled testimony?
A. Yes, they would.
Q. If you will look at Exhibit 6, I believe it would be, is that your prefiled testimony?
A. Yes, it is.
Q. And to the best of your information and belief, is the information contained in that exhibit true and correct?
A. Yes, it is.

MR. PEARCE: I will offer Exhibit 6 at this time, and I have no further questions.
MR. HOBERG: Any objection to Exhibit 6?
MR. BINEK: No.
MR. HOBERG: Exhibit 6 is admitted. Thank you, Mr. Pearce. Mr. Binek, did you have any questions of Ms. Mulkern?
MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:
Q. Ms. Mulkern, where in your filings can we find the northeast Bismarck expansion costs for 2003?
A. The northeast Bismarck expansion was included in the capital or the plant additions for 2003. The details of that were provided in data request responses.
Q. Are these costs included in the rate base?
A. Yes, they are.
Q. Are they included in depreciation?
A. The depreciation, yes, they would be.
Q. Are they included in operating and maintenance expense?
A. The ongoing, essentially, yes.
Q. Are they included in the high rate of

return?
A. I guess I really can't answer that one.
Q. Okay. I'd like to now have you turn to Statement I, page 2 of 6.
MR. HOBERG: Exhibit 2, the blue book here.
Q. (MR. BINEK CONTINUING) Do you have it?
A. Yes, I do.
Q. Would you please read that paragraph for the record?
A. "See pages 3 through 5 for Montana-Dakota depreciation rates as set forth in a study performed by Stone & Webster Management Consultants, Inc., as of December 31, 1992 for gas and common plant. See page 6 for internally developed rates as of December 31, 2001 for computer equipment and network equipment."
Q. Now would you please turn to page 5 of Statement I?
A. (Witness complies.)
Q. Did your internal studies result in substantial increases to certain depreciation rates?
A. Excuse me. Could you clarify that?
Q. Well, you listed depreciation rates there. Did these internal studies that you've performed result in any substantial increases to any of those

depreciation rates?
A. I believe that these accounts were ones that were not included in the Stone & Webster study and that's why they were developed internally. So they have not changed.
Q. Okay. I'd like to have you turn to page 4 of 6. Is that the Stone & Webster study?
A. Yes, it is.
Q. Is there an account 391 on that page?
A. There is an account 391, office furniture and equipment.
Q. Is that where computer equipment is supposed to be?
A. No. Computer equipment is contained in various subaccounts under the 391. That account would be just for office furniture and equipment.
Q. Did you do a complete depreciation study as of December 31, 2001 or only a piecemeal study of general and common plant?
A. Can you repeat the question again?
Q. Did you do a complete depreciation study as of December 31, 2001, or did you only do a piecemeal study of general and common plant?
A. We did not do a depreciation study as of December 2001, and these depreciation rates set

forth on page 6 were not done either at December 2001.
Q. I refer you back to page 2 of 6. Your last sentence says, "See page 6 for internally developed rates as of December 31, 2001 for computer equipment and network equipment."
A. That means those are the rates in effect as of December 31, 2001, not that they were developed based on December 31, 2001.
Q. When were they developed?
A. I don't recall the exact date that they were done. They were included or used in the last rate case.
Q. The last rate case for the gas utility?
A. Yes, the last rate case for the gas utility.
MR. BINEK: No further questions.
MR. HOBERG: Thank you, Mr. Binek.
Commissioner Reinbold, do you have any questions of Ms. Mulkern?

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. Ms. Mulkern, how long have you been at MDU? I missed that. How long have you been with them?
A. I started with MDU in 1981.

Q. Okay. In your work with MDU have you testified in other cases before the PSC?
A. I have testified before this Commission and Commissions in Montana and South Dakota and Wyoming.
Q. Okay. I was going to ask about the other states, but you answered before I asked.
COMMISSIONER REINBOLD: I have no further questions. Thank you.
MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. Ms. Mulkern, I'm going to ask you the questions I had asked Mr. Fox because I've been referred to you for those questions. And so I asked him, each 1 percent of each -- I have to get out my notes before me.
Each 1 percent of the rates of return, how many dollars does that represent? So, for example, on Exhibit No. 10 where it showed that MDU Gas, let's say in the year 2000, had 11.12 percent and then it dropped in the year 2001 to 1.6 percent, what does each one percent represent, how many dollars?
MR. HOBERG: Do you have Exhibit 10?

THE WITNESS: No, I don't.
Q. (COMMISSIONER WEFALD CONTINUING) It probably is a different dollar number each year.
A. Yes, I guess in -- I guess to try to clarify, in 2001 we had a rate of return on equity of 1.6 percent. And we're saying in 2003 we're going to need $2.84 million. So, basically, to bring us up from 1.6 up to a 13.25, we would need 2.8 million. That's approximate.
Q. The 1.6 return on equity is in the year 2001. And the 13.25, you would like that in the year 2002?
A. The 13.25 is the equity return that we have requested in this case for 2003.
Q. Yes. So did you say that it would take 2.8 million to bring you that number in 2003?
A. That's right.
Q. So what would it take to bring you to that number in 2002? Is it a different number?
A. Yes. I can give you that. It would take $2.2 million to bring -- for 2002 to achieve a 13.25 percent return on equity.
Q. Okay. Thank you. Then you had answered a question from Mr. Binek, but I needed you to show me where that information can be found. The expansion

into north Bismarck, how the costs were recovered from expansion, are they included in your costs for 2002 when you anticipate the rate of return to be zero or the return on equity to be zero?
A. The costs for the northeast Bismarck expansion are -- in the rate case are the same costs as for any other new customer. The customers in northeast Bismarck will be paying a contribution for any costs over the extension policy, and according to that, they would give a contribution. So the costs in the case are the same as for any other new customer. And, also, the volumes associated with those new customers are also included in the case. Did I not answer your question?
Q. So you gave a dollar figure earlier to how much money. You said something had been returned in discovery. Can you just share that with me, because I haven't seen those discovery?
A. It's included in the discovery response dated July 25, and it is response No. 2.
Q. And do we have that in the materials that have been shared with the Commission?
A. We provided copies to the Commission.
Q. Where would I find that?
MR. HOBERG: Mr. Binek, do you have copies

of those data responses?
MR. BINEK: We should have copies of them.
Q. (COMMISSIONER WEFALD CONTINUING) But I wondered whether they had been provided to the Commissioners as part of your case.
A. They were not part of the case that was filed initially, but they were provided as -- detail provided as a data request. We did give a copy -- sent a copy, I believe, to the Commission.
Q. All right. So I would go back into the record for that.
MR. BINEK: Those are not a part of the record, Commissioner. Data requests are not a part of the record.
COMMISSIONER WEFALD: She told me she sent a copy to the Commission so I'm assuming she sent a copy to us. Is that wrong?
MR. BINEK: To the Commission staff.
COMMISSIONER WEFALD: Then we don't see that.
Q. (COMMISSIONER WEFALD CONTINUING) So I'm asking, is that information confidential, or is it available to the Commissioners?
A. It's available to the Commissioners.
Q. Where would I find it?

A. If someone could provide a copy of the data request response.
MR. HOBERG: Well, you have all of those, Mr. Binek. Do you make those available to the Commissioners?
MR. BINEK: We can make those available to the Commissioners. The consultant -- they were data requests that were made by the consultants.
COMMISSIONER WEFALD: I would like to see it, just that one.
MR. HOBERG: Just the one.
MR. BINEK: Pat said he could find it. Do you want that to be an exhibit in the record, or what?
COMMISSIONER WEFALD: I would prefer if Ms. Mulkern can just tell me the answer, but she's referring me to this exhibit, to this data request, so I would just like to have the information.
MR. HOBERG: Ms. Mulkern, do you recall the question? Can you give the response without looking at the exhibit?
THE WITNESS: If someone would provide me with a copy of the data request responses, I can do that.
MR. HOBERG: Okay.

THE WITNESS: It's been a while. Can you repeat the question?

Q. (COMMISSIONER WEFALD CONTINUING) Thank you. I just wondered, the 500 -- you mentioned a figure and I don't know exactly what it was. You mentioned a figure for the cost for the expansion in north Bismarck.

A. Okay. I think what you might be referring to earlier is Mr. Fox was talking about the service lines, where the company will own the service lines, and that he gave a figure of $500,000 and that was for the total company. For North Dakota for owning the service lines, it's going to be about $184,000. For the Bismarck expansion project we have about $120,000 in for 2002 and about $150,000 in for 2003.

COMMISSIONER WEFALD: Okay. Thank you. That's all my questions.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

EXAMINATION

BY COMMISSIONER CLARK:

Q. Looking at that Exhibit 10, which is Mike Diller's memo to the Commission, what was the reason for -- what was the difference in 2001 compared with '98, '99, 2000 that drove the ROE down 10 percent?

A. There were various reasons. One of the main ones was the operation and maintenance expenses.

Q. That would account for how much of that?

A. About $770,000, or the difference in increase in operation maintenance expenses from 2000 to 2001.

COMMISSIONER WEFALD: Are you referring to a specific statement?

THE WITNESS: Not one that is included in the filing.

Q. (COMMISSIONER CLARK CONTINUING) So $770,000 out of -- what would the total be?

A. That was the increase from --

Q. So that would account -- 770,000 would increase the rest. Out of how much of an increase in expenses?

A. Out of 12.2 million.

Q. Okay. So we've got a ways to go there. What's some of the other?

A. Others would be --

Q. I'm just trying to get at what was, you know, so different about that year as opposed to the other years previous to it, the other three years previous.

A. There would be a difference in sales volumes between the two years that would have contributed, and then some of the other reasons we've given in the case that we filed, increases in depreciation and taxes other than income.

Q. Is there, you know, like one document that I can go to somewhere in the testimony or the file exhibits that's going to kind of break that down for me real easily?

A. One place you can look is in the annual report to the Commission that we file. There is a comparison in that report each year comparing to the previous year, so if you look in the report for 2001 there will be a comparison to the year 2002 in there.

Q. Let's go to the 770,000 for operating and maintenance. Could you break that down a little for me?

A. One of the increases would be, of course, due to labor expense.

COMMISSIONER CLARK: Maybe I should do this: Will Ms. Mulkern be available later on after staff?

Q. (COMMISSIONER CLARK CONTINUING) I assume you'll be part of the rebuttal.

A. Yes, I will.

COMMISSIONER CLARK: Okay. Maybe it would be better to delve into some of this more in-depth stuff later on after the staff case and during rebuttal. We can hone in on some of this stuff more specifically.

MR. HOBERG: Any further questions?

COMMISSIONER CLARK: No.

MR. HOBERG: Any further questions by the Commission of Ms. Mulkern? Mr. Pearce, any further questions?

MR. PEARCE: No.

MR. HOBERG: Mr. Diller?

EXAMINATION

BY MR. DILLER:

Q. I'm going to have to help the Commission in the end and to make sense of all this I want to make sure I understand your answer, Rita. You've mentioned a couple of numbers, 184,000 for the cost of the policy change, is that revenue requirements, rate base expense? What is that number?

A. That is the capital investment in plant for service lines.

Q. Just the capital investment. Is it the same answer for the expansion costs, that that's

rate base then?
A. That's right. That's also the capital addition for the plant.
MR. DILLER: Okay. Thank you.
MR. HOBERG: Thank you, Mr. Diller. Anything further then of Ms. Mulkern at this time? Thank you, Ms. Mulkern.
Mr. Pearce, witness No. 7.
MR. PEARCE: I'll call Richard Espeland.
MR. HOBERG: I guess it's not witness 7. Exhibit 7 is his testimony. Witness 5.
Mr. Espeland, did you hear the admonition I gave earlier in regard to perjury?
THE WITNESS: Yes, I did.
MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.
THE WITNESS: Yes, I do.
MR. HOBERG: Mr. Pearce, please.

RICHARD A. ESPELAND,

having been first duly sworn, was examined and testified as follows:
THE WITNESS: If I don't speak up loud enough, please tell me to try and force it out a little bit more.

DIRECT EXAMINATION

BY MR. PEARCE:
Q. Mr. Espeland, in the course of this case, did you prepare and have filed with the Commission direct testimony of Richard A. Espeland?
A. Yes, I did.
Q. Okay. And looking at Exhibit 7, if you will, is that the same testimony from you that was prefiled?
A. That's correct.
Q. And if I were to ask you the same questions, would you give the same answers today?
A. Yes, I would.
Q. And to the best of your information and belief, is all the information contained in your testimony true and correct?
A. It is correct.
MR. PEARCE: I'll offer Exhibit 7. At this time I have no questions.
MR. HOBERG: Any objection to Exhibit 7?
MR. BINEK: No.
MR. HOBERG: Exhibit 7 is admitted. Thank you, Mr. Pearce.
Mr. Binek, do you have any questions of Mr. Espeland?

MR. BINEK: Yes, I do have some questions.

CROSS-EXAMINATION

BY MR. BINEK:
Q. Mr. Espeland, you will agree that the costs of this plan have never been included in rates in North Dakota, wouldn't you?
A. That's correct.
Q. Why do you contend that the cost should now be borne by ratepayers?
A. When the program was implemented in 1982, it was not as common as they are today. It was more of a visionary plan. And today it's extremely common practice for these type of supplemental retirement plans to be in place. And it's appropriate for them to be in the rate base because it's part of doing business for those types of positions, as part of their total compensation program when you look at all of their compensation and benefits.
Q. Are you saying or suggesting that MDU's shareholders do not benefit from the efforts of these employees?
A. Both shareholders and customers benefit from these employees.
Q. But you're asking the ratepayers to pay

these costs, aren't you?
A. I think it's appropriate for the ratepayers to pay their portion of the cost for those employees, for the value they receive from those employees.
Q. But aren't you asking that the entire cost be on the ratepayers?
A. Yes.
Q. So you believe that the ratepayers are the only ones who benefit?
A. I think the ratepayers are the ones that have direct benefit from efficient, safe, reliable service. But, obviously, the stockholders of MDU Resources also benefits by a company that provides good services and a good rate of return and good customer service.
Q. Isn't one of the primary responsibilities of key employees is to make a profit for the company that in turn provides a dividend to shareholders?
A. That's correct.
Q. Your testimony in this case is essentially the same as it was in the MDU electric case that we heard a few months ago, isn't it?
A. That's correct. Yes, it is.
Q. Earlier I made reference to the findings of

fact, conclusions of law and order in the Commission's decision. In that case, which is PU-399-01-186, that decision issued on April 24, 2002, and the Commission has taken -- I believe has taken administrative notice of that decision.

Do you recognize the document that I've just handed you as a copy of that order?

A. I recognize it as what you referred to. I have not seen it previously.

Q. Would you please read paragraphs 66 and 67?

A. Paragraph 66, "Staff objects to including SISP in ratemaking expense. Diller testified that while the plan has been in effect since 1982, the company has never sought rate recovery in any subsequent electric or gas rate case. Staff opposes spending a million dollars a year on the benefit for a few employees. In addition to SISP, employees that are allowed to participate in SISP are paid very well, minimum of 75 to 80,000 per year, and participate in all other benefits offered to regular employees such as health insurance, life insurance, 401(k) participation, profit-sharing plans, incentive plans, defined benefit plans, Social Security, and discounted gas and electric service for those living in MDU's service territory."

Paragraph 67, "Diller testified that MDU's plan lacks symmetry and pointed out that the SISP benefits are heavily weighted in favor of the high-end salaried employees participating in the plan. For instance, an employee making $50,000 a year would receive a monthly SISP benefit of $1,330 per month, compared to a monthly benefit of $30,000 for an employee making $600,000 a year. In the case of a low-end employee, the monthly benefit calculates to be 2.66 percent of annual salary, compared to the high-end employee who would receive a monthly benefit of 5 percent of annual salary. Diller noted that only 27 employees of MDU's gas and electric employees are considered to be key employees."

Q. Is there anything factually incorrect in this description of Mr. Diller's testimony?

A. His facts and his math is correct to the extent it goes, yes.

Q. Okay. The number of employees, does that differ, the number of employees covered for this company, or is it the same employees basically covered?

A. Same basic group.

Q. And you read the description of benefits that these employees receive. Is that still true,

that they receive the same benefits that were described in the Commission's order in the electric case?

A. That's correct. Receive the same benefits.

Q. Isn't it true that even if this Commission doesn't allow the cost of this plan to be recovered in rates, the shareholders can continue to provide the benefit at shareholder expense? They can continue the plan just as it is right now, right?

A. Certainly they can and they may, because it's a competitive benefit that you need to attract and retain qualified people to run those operations and provide the service.

Q. What are the income ranges of the employees covered by this plan?

A. Montana-Dakota's range would be approximately $75,000 to its president, around 250,000 to 300,000.

Q. Does Montana include SISP as a cost to ratepayers?

A. I would defer to the regulatory staff on that, but I do not believe so.

Q. Does Wyoming include SISP as a cost to ratepayers?

A. The same answer. I would defer, but I

don't believe so.

Q. Same question for South Dakota?

A. And I don't believe so. I defer. At least I'm consistent.

Q. And as we've noted earlier, the North Dakota Commission has not included?

A. Not to this point.

Q. And, again, your testimony in this case and the position of Montana-Dakota Utilities Company is basically the same as it was in the electric rate case; isn't that correct?

A. That's correct. I provided a bit more information in my rebuttal testimony, but the basic facts remain the same.

Q. The electric case, a portion of that decision has been appealed by Montana-Dakota Utilities Company to the District Court. Isn't it true that the decision the Commission made on SISP, on the SISP issue, was not appealed?

A. I believe that is correct.

MR. BINEK: At this time, and I think administrative notice does this, but I just want to make certain that the findings of fact, conclusions of law and order in that electric proceeding would be incorporated into and made a part of this

proceeding.
MR. HOBERG: Yes, official notice would include that.
MR. BINEK: I have no further questions for this witness.
MR. HOBERG: Thank you, Mr. Binek.
Commissioner Reinbold, do you have any questions?
COMMISSIONER REINBOLD: I think I do, a couple of them.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. A good deal of the questions and the answers were relative to the electric case that was before us and the parallel. How can it be that the electric and the gas case benefits and circumstances are practically the same even though MDU has some areas of the state that are only gas and some that are only electricity? How do you account for the perfect parallel?

A. I'm not sure there's a perfect parallel, but the management group are similar and common. The amount of time they spend in the respective areas are allocated out based on where they spend their time, as would these costs. So we believe,

you know, as a group of costs and group of employees and it's allocated out based on where they do their work. Some may be full electric and some may be full gas, and others are split.

Q. Maybe some are just -- is the company something like Melroe? Is that a parallel in management and management salaries, and so on, to MDU? Do you know anything about Melroe here?

A. That keeps changing, but it's similar for the Bobcat division, so to some extent, but more Ingersoll-Rand would be a parallel to MDU Resources at a corporate level, but we don't pay those kind of salaries or benefits.

Q. And say a few words about MDU employee retention. How does MDU do? And compare it to whatever you want to compare it to. That's a pretty broad question. Take a shot at it.

A. I think retention is one of our goals, because if you want safe, reliable service, you need people that know history and what's been going on in the past, as well as how it all works. So retention is a goal and I think we've been very successful at that, providing a great place to work, providing competitive pay and benefits to the extent we're allowed to, and having them motivated by what they

do, providing a public service. There's a lot of motivation in that. And so I think we are a desirable place to work.

Q. So that's one of your goals you say?

A. Oh, absolutely.

Q. Getting back to the allocation of time and effort and salary because of the natural gas and the electric services, is it conceivable that, for example, somebody like Don Ball would be working 85 percent in natural gas and 5 percent in electricity?

A. Currently, I suppose his current time is spent more on the gas side than electric side because of the rate case, but I think over time that would not necessarily be true, but Mr. Ball would know better how he allocates his time.

Q. Just a curiosity on my part because we do see him a great deal. And nobody was going to catch on the fact that I don't add up to 100 percent here.

MR. HOBERG: Where's the other 10 percent?
THE WITNESS: We consider that overtime and extra effort.
COMMISSIONER REINBOLD: I guess that's all my questions. Thank you.
MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. How many dollars is the company requesting in this case for SISP?

A. For the gas case I believe it's between 250 and $260,000 per year for 2002 and 2003.

Q. Where would I find this information? Where would I find that dollar number?

A. I'm going to defer in part to Rita and Tamie, but I found it someplace.

Q. Just take your time.

A. I believe it's in Statement N, as in November, page 8 of 23.

Q. Thank you. Page 8 of 23. It shows zero for the year 2001?

A. That's correct.

Q. And that's because nothing was allowed by the Commission?

A. Right. It has not been included previously.

Q. And so then you showed in 2002 a number and then 265,000 in 2003?

A. Right.

COMMISSIONER REINBOLD: Okay. Thank you.
MR. HOBERG: Thank you. Any further

questions, Commissioner Wefald?
COMMISSIONER WEFALD: No.
MR. HOBERG: Thank you. Commissioner Clark, please.
COMMISSIONER CLARK: I have no questions. Thank you.
MR. HOBERG: Thank you. Mr. Pearce, any further questions of Mr. Espeland?
MR. PEARCE: Just a couple.

REDIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Espeland, I think you've already alluded to this indirectly, but it is true, isn't it, that all of the SISP costs is not assigned to all of the utility operations?
A. Oh, absolutely. Only the portion that would apply directly to the utility.
Q. So SISP is applied to other operations?
A. Yes.
Q. Now, the meter fact that Montana-Dakota Utilities didn't appeal the SISP decision doesn't mean that you've changed your mind, does it, on the value of SISP?
A. Has not changed my mind at all.
Q. And all of the ratepayers benefit from all

of the compensation given to or provided for employees, don't they?
A. That's correct.
MR. PEARCE: That's all I have.
MR. HOBERG: Thank you, Mr. Pearce. Anything further then of Mr. Espeland?
MR. BINEK: No.
MR. HOBERG: Thank you, Mr. Espeland.
THE WITNESS: Thank you very much.
MR. HOBERG: And your next witness, please, Mr. Pearce.
MR. PEARCE: Call Mr. Russell Feingold.
MR. HOBERG: Mr. Feingold, were you here earlier when I gave the admonition in regard to perjury?
THE WITNESS: Yes, I was.
MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, respond I do.
THE WITNESS: I do.
MR. HOBERG: Thank you. Mr. Pearce, please.

RUSSELL A. FEINGOLD,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Feingold, you were retained in this proceeding by the applicant as an expert outside consultant; is that right?
A. That's right.
Q. And did you prepare or have prepared under your direction and control direct testimony consisting of answers and questions that was prefiled in this case?
A. Yes, that's correct.
Q. Looking at Exhibit 8, if you would, does that contain -- is that a copy of your prefiled direct testimony?
A. Yes, it is.
Q. Do you have any corrections that need to be made in your prefiled testimony?
A. No, I don't.
Q. To the best of your information and belief, is the information in that testimony, Exhibit 8, true and correct?
A. Yes, it is.
MR. PEARCE: I'll offer Exhibit 8. I have no direct questions.
MR. HOBERG: Thank you. Any objection to

Exhibit 8?
MR. BINEK: No objection.
MR. HOBERG: Exhibit 8 is admitted.
Mr. Binek, do you have any questions of Mr. Feingold on direct, please?
MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Feingold, on page 5 at lines 15 through 18 you discuss the wider acceptance of three-part rates for gas distribution service. Do you see that reference in your testimony?
A. Yes, I do.
COMMISSIONER REINBOLD: What number?
MR. BINEK: Lines 15 through 18 on page 5.
COMMISSIONER REINBOLD: Thank you.
Q. (MR. BINEK CONTINUING) Would you describe these rates?
A. Yes. These rates generally consist of tariffs that include a rate structure with multipart components of rates. Typically, there's a -- for gas companies a commodity charge, which would be charged on a variable basis, and then there would be fixed charges, in some cases a demand charge or a capacity charge and then a customer or monthly

service charge.
Q. I take it you believe that these are preferable to the two-part rates now in use by MDU in North Dakota; is that correct?
A. They are preferable from a strict cost recovery perspective. I think I allude in my testimony to the fact that in some cases for smaller customers you may not be able to apply a three-part rate as easily as you would to a larger customer.
Q. Why haven't you proposed these rates for MDU?
A. Well, I think you'd have to ask MDU's company witness, but I can give you my perspective from the standpoint of someone who is commenting on the tariffs. And I believe that with regard to the smaller customers, i.e., the residential customers, there is not metering capability at this point to fairly apply a three-part rate to the smallest customer served on the system. In lieu of that, though, one of the proposals that the company is making is to try to recover a greater component of fixed costs from fixed charges, which is why the company has proposed the monthly service charge proposal it has.
Q. If you were to propose three-part rates, to

what types of customers would they apply?
A. Well, if I look at other utilities in North America, typically the ones that have three-part rates applied to them first and foremost are larger, more sophisticated customers where the economics permit the use of daily demand metering technology or equipment to be able to fairly assess at least the demand or capacity component of the charges.
Q. Do you recommend that this Commission direct its gas utilities to develop three-part gas rates?
A. I think it's something that's worthwhile looking at in the future. I think in response to a data request that was asked of me by staff I alluded to the fact that in Connecticut, for example, the Commission in Connecticut has actually looked at and has approved three-part tariffs for midsize general service type customers.
Q. Much of your testimony is devoted to supporting the company's proposed increases in customer charges; is that correct?
A. Yes. Although, I would say more generally it's to recognize the fact that fixed costs should be recovered from stable or fixed components of the tariff.

Q. Are you familiar with similar proposals in other states?
A. In other states served by the applicant?
Q. By the applicant or in other states in general.
A. Yes.
Q. In both cases?
A. Yes.
Q. Have these proposals encountered much opposition?
A. Well, I'm not sure how you define "much opposition." Certainly, from my perspective, they're eminently reasonable. And in some cases there has been a disproportionate amount of movement toward cost-based fixed charges.
Q. Where there has been opposition, from whom has the opposition been expressed?
A. The opposition has been expressed primarily from consumer advocates, entities that are representing smaller, perhaps lower income customers, because their contention is that perhaps those customers would be experiencing a larger increase than would be warranted at that point in time.
Q. Have Commissions generally supported

efforts to double or triple customer charges as Montana-Dakota Utilities proposes in this case?
A. Well, I think, first, in the case of Montana-Dakota the proposal is to move from a $6.50 per month charge to $11.70, which is 39 cents per day as proposed. I don't think I've seen tripling of proposals as you are suggesting.
Q. What about the large customer?
A. What about large customers?
Q. Have their rates more than doubled or proposed charges, customer charges more than doubled?
A. Yes. However, it's a very different situation with larger customers because the revenues or the billings that are associated with the fixed monthly charge is a much larger -- smaller percentage of the customer's total bill, so they don't see it in the same way that a smaller customer would necessarily --
Q. But would you agree --
A. -- so it is more acceptable to Commissions, in my experience.
Q. I'd like to have you turn to page 8 of your testimony, lines 18 to 19. There you mentioned FERC's straight fixed-variable rate design for

interstate pipelines. Would you please describe that rate design?

A. Yes. Essentially, the FERC fixed-variable rate design is a -- I characterize it as a cost classification and allocation method that recovers fixed costs through a capacity or demand charge and variable costs through a commodity charge.

Q. Isn't the fixed part of that rate design tied to the maximum volume throughput of the customer and not to the customer's existence as a pipeline user?

A. Yes. And rightly so because pipelines don't serve hundreds of thousands of customers as an LDC does so they don't tend to classify and treat those costs in the same way that an LDC does.

Q. Would you agree that the appropriate analogy to FERC's fixed charges at the distribution level would be to a demand charge such as you discussed earlier and not to current customer charge?

A. From a strict rate design point of view, I would agree with you, but we have to recognize that some of the costs that are captured in the pipeline's capacity charge are costs that are appropriately recovered in the monthly customer

charge for an LDC.

Q. From page 12 on in your testimony you discuss the alternative distribution delivery stabilization mechanism which the company is proposing as an alternative to increasing customer charges. Just to refresh the Commission's memory, would you please provide a brief description of this mechanism?

A. Yes. The distribution delivery stabilization mechanism or more appropriately, the acronym DDSM, is a proposal that essentially adjusts the company's non-gas costs or a distribution margin to reflect changes in consumption as a result of changes in weather patterns.

Q. Do other utilities in other states have weather normalization adjustment mechanisms?

A. Yes.

Q. Are you familiar with these adjustments?

A. Yes, I am.

Q. Can you describe some of those mechanisms?

A. I'm not sure what aspect you're actually looking for me to describe beyond the general description I just gave you, which is essentially defining how all of the other mechanisms that I'm familiar with operate generally and what -- their

structure to accommodate.

Q. Do those mechanisms typically have a year's delay in the pass-through of the effect to warmer or colder weather?

A. There are some distribution utilities in North America that do have that feature, yes.

Q. Do most of them?

A. Most of them do not.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, do you have any questions of Mr. Feingold?

COMMISSIONER REINBOLD: Just a couple of questions.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. Have you been to North Dakota before this hearing?

A. Yes, I have, but have not testified before.

Q. Okay. Have you ever been to Mandan, North Dakota?

A. Yes, I was, and I think I was lost when I was driving.

Q. Okay. I don't have any real -- well, I've got a couple questions here just to make sure you

earn your money. RAFFCOSNCIFERCDDSMWNADSANUADZCK. What did I just say?

A. You mentioned every acronym that's in my testimony.

Q. Do you believe what I said to be an acronym?

A. It's a pretty long one, but, yes, I do.

Q. Quite technically it's not an acronym, unless it sounds like it might be a word and I can't imagine any of these being a word.

COMMISSIONER REINBOLD: That's all the questions I have at this time, but stay loose.

THE WITNESS: Okay. Thank you.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. On page 9 of your testimony -- I have trouble seeing the lines. I think it's 18 through 20 on page 9.

A. Yes.

Q. The proposed basic service charge increases will also ensure recovery by the company of a greater portion of its fixed costs of providing service.

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If the higher customer charges were put in place, what proportion of the -- what proportion of the amount of income that MDU wishes to recover would be recovered by the basic service charge?

A. I think the way that I could answer that, Commissioner, is if you turn to page 10 of my testimony --

Q. Okay.

A. -- lines 20 through 23, I try to quantify, I think, the question that you posed, and that is if the monthly basic service charges were increased, and I focused on the residentials and general service customers, I talk about the amount of fixed costs that would be recovered. So, for example -- well, on page 10 in particular I say that there's still roughly $1.5 million of remaining customer-related costs and 3.3 million of fixed demand-related costs represented by 25 percent, so we're saying that roughly 75 percent of the fixed costs for the residential and general are recovered through the customer charge or monthly service charge.

Q. That being the case, would MDU have a greater opportunity to overreturn from those customer -- let's say the residential customer

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group?

A. I don't believe so. And the reason I say that is because the costs that would be recovered in those basic monthly service charges represent the non-gas cost margin that would be established as a result of this rate proceeding. So under the assumption that that set number of dollars that represents distribution margin is what the company requires to have the opportunity to earn a fair rate of return, it's entirely appropriate to recover those in the fixed charges of those classes, but it doesn't in any way suggest that there would be the opportunity for overrecovery because of the way that they are being recovered through those charges.

Q. Why wouldn't there be an opportunity for overrecovery? Because in some years even with the present -- even with the present rate structure, if you have a really good year where it's cold and you're selling a lot of natural gas, then you're able to recover more income, and so why wouldn't that just be exacerbated then? I know you're going to be decreasing the cost of the natural gas to some extent for those customers, but still if you have a year where you're selling more than the normal, just explain that to me, why that would be there.

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A. Certainly. I mean, if we recognize that the monthly service charges are applied on a customer's bill by essentially a monthly charge, so, in other words, if you have a $10-per-month monthly customer charge, whether you use zero decatherms of gas or 10 decatherms of gas in a particular month, you will be charged $10 because that reflects the recognition that the company incurs fixed costs that don't change whether the customer uses zero gas or 10 units of gas. Okay. So if it's a colder than normal year versus a warmer than normal year, it will not impact that $10-per-month charge applied to the number of customers served by the utility. In fact, it takes weather-sensitivity away from the utility business and instead of exacerbating, actually ameliorates the situation that you talk about with swings because of weather and that's one of the main reasons that this is being proposed.

Q. Are you the person to ask questions about how the rate design was done to establish that this is the correct amount of the residential gas service charge?

A. Well, I think the best person to ask that would be the next witness, Mrs. Aberle, but what I can answer here is that in reviewing the company's

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embedded cost-of-service study, I was convinced that the numbers that came out of that study formed the basis for evaluating what rate level should we set in this case, so I'm comfortable with that connection. But I think she can talk to it in more detail.

Q. But it all depends on the assumptions that are put into that gas cost-of-service study as to which things are given to which customer group, correct?

A. That's correct, but I would venture to say based on my review of Mr. King's testimony, that with regard to the customer-related costs that form the basis for the monthly service charges, staff and the company are really not that far apart. It's a matter of how far do you go and how fast to get to cost-based rates.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

COMMISSIONER CLARK: I have no questions. Thank you.

MR. HOBERG: Any further questions then of Mr. Feingold? No further questions. Thank you, Mr. Feingold.

THE WITNESS: Thank you.
MR. HOBERG: You have one more witness on direct?
MR. PEARCE: Yes. I'll call Tamie Aberle.
MR. HOBERG: Ms. Aberle, were you here earlier when I gave the admonition in regard to perjury?
THE WITNESS: I was.
MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.
THE WITNESS: I do.
MR. HOBERG: Mr. Pearce, please.

TAMIE ABERLE,

being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Did you prepare the direct testimony of Tamie Aberle that's been prefiled in this case?
A. I did.
Q. Looking at Exhibit 9, is that a copy of your testimony as prefiled?
A. Yes, it is.
Q. And if I were to ask the same questions,

would you give the same answers as are in that testimony?
A. Yes, I would.
Q. And to the best of your information and belief, is all of the information contained therein true and correct?
A. Yes.
MR. PEARCE: I will offer Exhibit 9 at this time, and I have no further questions on direct.
MR. HOBERG: Any objection to Exhibit 9, Mr. Binek?
MR. BINEK: No.
MR. HOBERG: Exhibit 9 is admitted. Thank you, Mr. Pearce. Mr. Binek, any questions of Ms. Aberle?
MR. BINEK: Just a few.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Concerning your proposed distribution and delivery stabilization mechanism that you discuss on page 12 of your testimony, do I understand this mechanism is being proposed only as an alternative to the dramatic increases in customer charges?
A. It is our secondary proposal in lieu of the increased customer service charges that we have

proposed.
Q. Okay. So does this then mean that if the company get the customer charge increase it is seeking in this case, the DDSM proposal is withdrawn?
A. Correct.
Q. What if the company get no rate increase whatever or even a rate reduction, what happens to the DDSM proposal?
A. I'm sorry. I believe I might have misspoken on your earlier question. I was speaking of the increase in the basic service charges, not the overall revenue increase. Our DDSM proposal would apply regardless of the increase or decrease in the overall rates, if we were not to receive the basic service charges that we proposed.
Q. Okay. But if you got the basic service charges, then you're not seeking the DDSM?
A. Correct.
MR. BINEK: That's all I have for right now.
MR. HOBERG: Thank you, Mr. Binek.
Commissioner Reinbold, do you have any questions?
COMMISSIONER REINBOLD: None at this time.

Thank you.
MR. HOBERG: Thank you. Commissioner Wefald, please.
COMMISSIONER WEFALD: No, I have no questions at this time.
MR. HOBERG: Thank you. Commissioner Clark?
COMMISSIONER CLARK: None. Thank you.
MR. HOBERG: Anything further then of this witness at this time?
MR. PEARCE: Nothing.
MR. HOBERG: Thank you, Ms. Aberle.
Let's take a 10-minute recess at this point.
MR. BINEK: Could we take a little bit longer time? I wasn't anticipating that my witnesses would be going up this soon.
MR. HOBERG: Fifteen minutes?
MR. BINEK: I think 15 minutes.
MR. HOBERG: Okay. We'll be back at 25 to 3:00, please.
(Recess was taken.)
(Exhibits 15-48, 16 and 17 were marked for identification.)
MR. HOBERG: We are back on the record

after a fairly short recess.

Before we begin the direct -- or the presentation of the State's case, we perhaps have some unfinished business. We have a couple of exhibits from MDU, is that correct, Mr. Pearce?

MR. PEARCE: Yes. I don't believe that I formally offered Exhibits 1 and 2. That's the application and the book of statements. I'll offer them at this time.

MR. HOBERG: Mr. Binek, any objection to 1 and 2?

MR. BINEK: No.

MR. HOBERG: Okay. Exhibits 1 and 2 are admitted. Thank you. Mr. Binek, please.

MR. BINEK: Thank you. I'll call Charles King.

MR. HOBERG: Mr. King, did you hear the admonition I gave in regard to perjury earlier?

THE WITNESS: Yes, I did.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: Yes, I do.

MR. HOBERG: Thank you. Mr. Binek, please.

CHARLES W. KING,

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BINEK:

Q. Please state your name for the record.

A. My name is Charles W. King.

Q. And what is your occupation, Mr. King?

A. I'm president of the economic consulting firm of Snavely King Majoros O'Connor & Lee.

Q. And what is your address, business address?

A. 1220 L Street N.W., Suite 410, Washington, D.C.

Q. Mr. King, have you -- how long have you been engaged in your present occupation?

A. In the present occupation close to 40 years. Virtually all my professional life.

Q. And you have testified in a number of state utility rate proceedings?

A. Yes. I've distributed a listing of my appearances and if you count them up, they come to over 300.

Q. Okay. And you have also appeared before the North Dakota Public Service Commission, have you not?

A. Yes. I appeared in MDU's electric case earlier this year and last year in Xcel's gas case.

Q. Let's see. Mr. King, I show you what has been marked as Exhibit 15-48. And can you identify that exhibit?

A. That's my testimony. I believe my exhibits are attached to it. Yes.

Q. And was this testimony prepared by you or at your direction?

A. Yes, it was.

Q. Are there any corrections that need to be made to your testimony?

A. No, there are not.

Q. And if I ask you the same questions today that are in your testimony, would your answers to those questions be the same as stated in your prefiled testimony?

A. Yes, they would.

Q. You also have before you Exhibits 16 and 17. Would you identify those exhibits?

A. One of them is a month-by-month statement of MDU's working capital, and the other one is an exhibit from the earlier MDU case, the electric case of earlier this year, and -- which shows the respective revenue sources for a number of

utilities.

MR. BINEK: Okay. At this time I will offer Exhibits 15, 16, and 17.

MR. HOBERG: Mr. Pearce, any objection to any of those exhibits?

MR. PEARCE: No.

MR. HOBERG: Exhibits 15, 16, and 17 are admitted.

MR. BINEK: Thank you.

Q. (MR. BINEK CONTINUING) At this time, Mr. King, I would like to ask you to give a summary of your testimony and also any rebuttal that you -- or any responses that you might have to the rebuttal testimony that has been filed by Montana-Dakota Utilities in this case.

A. Certainly. In the interest of time, I don't think I will go through in detail the portions of my testimony principally relating to rate design where I don't think there is any disagreement between us and the company. Unfortunately, most of my rate-of-return testimony there is disagreement.

The testimony overall deals with four subjects; the rate of return, cost allocation; that is, classed cost allocation, rate design, and, finally, the DDSM proposal. The cost -- I'm sorry.

Cost-of-capital testimony in turn has three parts. One is capital structure. The other is cost of the debt, and the other is cost of equity, and we don't seem to agree with MDU on any of them.

With regard to capital structure, there are two disagreements. One is that I include short-term debt and the company does not. And the other one is I used a historical 2001 capital structure and the company does a projected 2003 capital structure.

With regard to short-term debt, the reason for including short-term debt is that portions of the rate base are financed by short-term debt. If short-term debt were used for things totally out of rate base, such as expenses, then maybe we could exclude it, but, obviously, when you have elements that are in the rate base that vary throughout the year, why the company has to use short-term debt to finance that. And that's why I have my exhibit -- what is it -- 16 or 15? I didn't write it down. Sixteen, and this is taken from the company's Statement E.

And it's -- unfortunately, it is four of the five items that make up working capital. I did not -- I neglected to put in DSM expenses, but it wouldn't detract from what the exhibit shows, which

is throughout the year there is significant variation in the amount of working capital. And when you have that kind of variation, it's necessary to finance it through short-term debt. So I suggest that contrary to what the company says, it does not finance its working capital with long-term debt and equity, that there is an element of short-term debt. To be sure, it is a small amount. And you will find in my capital structure a relatively small amount of short-term debt.

As regards the forecast capital structure, the company's position in this case is considerably different than it was in the electric case. In the electric case the company accepted a historical end-of-year 2000, in that case 2000 capital structure. In this case the company wants a forecast capital structure. And I think it's mid -- it's the average for the year 2003. Now, the reason one uses future test years is to capture exogenous effects or outside effects, such as inflation, and in this case, the necessary expansion of the system into the northern suburbs of Bismarck.

These are things that are objectively determined. They are reasonably knowable. They are reasonably objectively analyzed. The capital

structure of the company is a creation of its own management. If the company says that its capital structure is going to change, there is no way of determining that, in fact, it will change in that manner. For this reason, most Commissions use historical -- recent, but historical capital structures, unless the company can articulate why the capital structure will change. Otherwise, you invite the company to engage in gaming of the regulatory system by projecting a capital structure usually with more equity than debt so that the overcomposite becomes more expensive. And I don't think the company should be permitted to do that in this case.

The debt cost we have a significant difference in. The company is proposing that the debt be limited to first mortgage bonds with a cost of 9.302 percent. I have proposed that we use a parent company's debt cost, which includes 6.167 percent. If -- I don't know if you want to look it up, but if you would want to look it up, Statement A, which is the company's balance sheet.

MR. HOBERG: In Exhibit 2.

THE WITNESS: Statement A in Exhibit 2. And earlier I asked Mr. Keller -- we asked

Mr. Keller whether the first two pages were for MDU Utilities Company. He answered yes. And if the subsequent pages pertain to MDU Resources Group, and the answer to that was yes. If you turn to page 11 of the Statement A, you'll find a list of long- term debt. That list does not begin to match the list that Mr. Keller has presented in Statement F, which is where he proposes his debt costs. The only debt that he shows is the secured medium-term notes, Series A, and then pollution control refunding revenue bonds. These are merely a portion of the parent company's total debt. Not included are -- and he has about 133,000 of first mortgage bonds. Not included are senior notes, $405,000 -- million dollars. Commercial paper, $219 million. Revolving line of credit, $25 million. Term credit agreements of $11 million and pollution control note obligations of $11 million -- I'm sorry -- $2.5 million. The company has reflected only a portion of its total debt.

Now, in rebuttal Mr. Keller has said that that doesn't -- other debt doesn't pertain to MDU Utilities, but you heard a few minutes ago that MDU Utilities Company isn't really a company. It's simply a division of the larger company. The larger

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company is the entity that generates the debt, that raises the debt and distributes it to the subsidiaries. What the company has sought to do here is to build a firewall between the debt it wants to assign to the regulated piece and the debt it wants to assign to the unregulated piece. And, surprise, the debt it wants to assign to the regulated piece is 9 percent, and the debt it wants to assign to the unregulated piece ranges all the way down to 2 percent. And it should not be allowed to gain the system this way, by pretending that some debt pertains to the utility operations and other debt pertains to the non-utility operations.

Mr. Keller will tell you that that's how the debt instruments are written. Of course, they're written that way because that was how they were intended to be written so that they would appear that there is a distinction between debt raised for the utility and debt raised for the non-utility. Truth is, debt is all fungible. It could be spent anyplace the company chose to spend it. For that reason I have used the blended rate, debt rate of the entire company, meaning MDU Resources, as the debt cost. And it makes a very, very significant difference in the result. The debt

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cost -- let me get my notes here -- again, is 9.3, if you use the company's first mortgage bonds as it proposes. It's 6.2 or 6.167, if you use the parent company's blended debt, which I developed in an exhibit to my testimony.

Now, equity, I have to kind of go through and tick off the items where Dr. Gaske and I disagree. The reality is we agree on a lot of things, specifically the formula for discounting cash flow, but, first of all, Dr. Gaske wants to include flotation costs. We're doing this all over again. In the electric case I demonstrated, and I simply repeat it in this docket, that if you include flotation costs, they come to .1 percent of the cost of the value of the total equity of the company. And I'm game to include that as a component of capital costs, but it would be lost in the rounding. Dr. Gaske seems to believe that it is appropriate to assign the incremental cost of flotation relative to the newly-issued stock and take that percentage and apply it to the entirety of equity. And this is a gross overcompensation of the company, and in the last case the Commission explicitly agreed with me.

Now, selection of comparison companies, Dr. Gaske point out correctly that in the Xcel

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case -- I'm sorry -- in the last case. Two things, he points out in the Xcel case that I used a much different and smaller group of companies and I used both gas companies and combination companies. And the answer is I didn't really pick those companies. In that case I was rebutting Dr. Olson, who had made the pick. And rather than fight with Dr. Olson over the pick, I accepted his listing.

In the last MDU case, the electric company case, I took some purely electric companies and some combination companies, and I argued that the combination companies were more representative of MDU's electric service. And I was going to do what Dr. Gaske suggests, which is include full gas companies and combination companies until I looked at what has now been marked Exhibit 17, which is an exhibit that I entered into -- in the MDU case. And it shows the proper portion of the revenue of each of these companies. The companies in boldface are the ones I wound up selecting. If you look at those companies and look at the electric revenue and then look at the gas revenue, what you'll see is in every case the electric revenue is a multiple of the gas revenue. And as a consequence, while one can say that the investors might view these companies as

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electric companies that also provide gas service, it doesn't work the other way around. No one views these companies as gas companies that also provide electric service, which is why I did not include these companies in my comparison group this time. Instead, I included purely gas companies.

Now, the other -- well, let's go through what I did that I don't think Dr. Gaske and I disagree with on. I used the DCF formula and I did two -- three versions of it. First, is the so-called classic version, which Dr. Gaske has another name for, and we also used pretty much the same sources; Zacks for the future forecast of earnings growth. And then we did the same development of dividend yield. We had the silly little disagreement over whether the growth factor for next year's dividend should be .5 -- or .5g, g being the growth factor, or .625g. And Dr. Gaske says that I don't reflect the time value of money. And he's right. I didn't. I just took half a year and said, all right, that's the probable time the next dividend increase will occur so we take one-half of growth, which seems logical.

Now, if I were to include the time value of money, I would probably reduce that .5. Why?

Because a dividend increase six months from now is worth less than a dividend increase right now. So I would have to take -- I would have to reduce that .5 by some factor reflecting half a year's loss in value because of the time value of money. So instead of increasing it as Dr. Gaske has done, I would have reduced the factor. But, again, we're talking about peanuts here in terms of impact on the total results.

The other thing I did was similar to Dr. Gaske's formula. I took the retention rate of the respective companies as determined by their dividend payout ratio or their earnings retention ratio times Value Line's forecast of their future return to book equity. And unlike Dr. Gaske, I added a piece for the probable or the likely increase in value that one would get from selling -- or companies would get from selling stock at greater than book value, which would enhance the book value of the shares. And I developed an internal retention growth estimate. And then I used -- I did get out the history of earnings gross and I developed that, and I think Dr. Gaske and I both agree that that probably isn't worth a whole lot.

I then developed what I regarded as the

composite rates of return for each of the 11 companies that I picked, as opposed to I think five or six that he used. And that was a judgment call, and Dr. Gaske is very unhappy with what I did there. But if you look at it, you will see what I have done in each case is taken the classic DCF return, which is probably the best estimator, and then turned and looked at the retention growth method. If the retention growth looks like it's totally out of whack with the forecast, and in some cases they are, simply no way that the company could be growing as fast or as slowly as the investor survey shows, I modified that classic DCF in the direction of the retention growth. And I came up with 11 estimates of the overall rate of return.

Then when I got those 11 estimates, I went through a little analysis of whether MDU is more or less risky than those 11 companies. And I determined a couple things. One is MDU has relatively high equity proportion in its capital structure, which saves it from a lot of financial risk that the other companies have. It was about equal to the best or the highest of the equity ratios. I don't pretend that that is the predictor of relative risk, but it is an element of relative

risk. Another element of relative risk is how much nonregulated activity the company has. In general, it's accepted that unregulated activities are riskier than regulated activities. Why? If your earnings are short, you come into a Commission like this and you get an increase in your rates. You have monopoly power. There is never a question that you're going to collect the money if the Commission let's you do it because you are a monopoly. That's not true of any unregulated activities. By definition, unregulated activities simply don't have the degree of security, the low-risk properties that regulated activities have.

There are a couple of other reasons I didn't mention in my testimony I probably ought to bring up now. Earlier in the day we heard from Mr. Fox that MDU was facing competition from propane and oil. Now, I live in Washington, D.C., and have done a lot of cases involving Washington Gas Light Company and so I'm familiar with competition there. There was no mention of competition from electricity. In Washington, D.C., the -- about two-thirds or three-quarters of the entire commercial load has been lost by the gas industry or the gas company to the electric company. And the

reason is that's a warmer climate. In Washington the climate is warm enough that you can build a compressor in an air-conditioning system that also heats. You can't do that in this climate. It would be ruinously expensive. Residentially you can sell people a heat pump. Heat pumps simply don't work in North Dakota. You freeze to death, along with paying an astronomical electric bill. So the relative degree of competition for gas in North Dakota, I submit, is considerably less than it is elsewhere in the country.

There's another difference. In Washington and even in Spades and Atlanta there is a much more active competitive supplier business. In Atlanta, the other company I'm familiar with, the Commission decided to totally restructure the gas industry. That no one -- the utility would no longer buy gas on behalf of its customers. It would have instead merchants would come in and you would be a customer of the ABC Gas Company, which would buy your gas and pay Atlanta Gas Light to deliver it to your house. So that from 600,000 customers, Atlanta Gas Light went to 11 customers.

That sounded like a wonderful idea, except that one of them with a nice Georgian name of

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Peachtree Energy went bust and left Atlanta Gas Light hanging for quite a few million dollars, just stiffed them flat, and the company suffered a very significant loss. And Washington Gas Light has a similar problem. They've lost about two-thirds of their commercial load to competitive suppliers. Now, they still use WGL as their delivery to customers. One of the problems is that they haven't got the transportation capacity locked up that WGL had. And there's a great fear that if we have a cold winter, these people aren't going to be able to get the gas into Washington. Those are risks that larger companies have that MDU doesn't have because MDU does not seem to have anything like the active competition for the gas supply business that you get in bigger places.

So I think that is an important difference between MDU -- those two, the degree of competition and the effect of suppliers, is an important reason why MDU is probably less risky than the average utility, in addition to the point that I make in my testimony. Dr. Gaske says that MDU has the risk characteristics of a small company. Well, he's comparing apples and oranges. He's comparing the gas distribution business of a large company with

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the risk properties of a small company, a small stand-alone company. What we're trying to find is not that. We're trying to find the risk characteristics of the gas operations of a large company. A large company gives you the security of financial strength and also diversification of financial resources. You remember where all those extra sources of debt came from, which a small company doesn't have and small companies indeed are more risky, but only when they are stand-alone operations. Principally, because their sources of financing and the support they can put behind that financing in terms of business is much less.

Well, all this comes together on page 34 of my testimony where I present my composite cost of capital and that is -- there I take the proportion of the capital structure, the cost elements, and the weighted costs. I've come up with 10.5 percent as a cost of equity, which is halfway between the average cost of equity of my 11 companies and the lowest cost of equity within that category, that group of 11 companies, reflecting the fact that MDU is less risky than the average for the 11. That's 10.5 and then you get the weighted cost in the final column, overall return to capital is 7.98.

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Now, the rest of my testimony deals with capital structure. The only area where I think I seem to hear disagreement from the company pertains to the cost of service study. Where Ms. Aberle says that customers cause most or half the cost or a third of the cost, I believe is their position, of the mains system. And I take exception to that.

And the reason is that the main system may be driven by the addition or -- well, never the subtraction, but always the addition of customers, but only out in the margins. Indeed, they're putting more mains out in north Bismarck, but you heard testimony earlier that they only add 1 percent more customers every year, so that's a negligible impact on the cost of mains. Most of the cost of the mains is what you call an embedded cost. It's there. It's been there for centuries -- I mean, for decades. And it's not going to be affected by any increase or decrease in the number of customers. It's not going to be affected by any increase or decrease in the amount of gas that goes through it. It will be impacted by the maximum amount of gas that goes through in any one day, but we reflect that. We recognize that in allocating a portion of the main's cost to throughput as among the various

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classes of customers.

My -- when you can't find causation and that's the case with mains. They are simply there, what I would call an institutional cost. They're not caused by anything. They're there. When you can't find causation, then maybe you should look to value of service as an allocator. And value of service is measured by the amount of gas delivered to each of the three or four various categories of customers, which is what I have done in the alternative calculation that I have presented. And it does change the results some, but not a whole lot. We both agree that the small interruptible customers are being overcharged. We don't agree quite about what to do about it. The company would reduce their rates while increasing everybody else's rates.

I went through a number of previous Commission decisions, not just with MDU, but with all the other gas companies and also electric companies, and it appears to have been this Commission's policy over the years that when there is a rate increase, everybody ought to bear a little of the pain. And if you want to even out differences among the classes, you might change the

percentage increase, but everybody get some increase. And what I have seen is a number of cases where the overcharged class got half the increase that the undercharged class got. And that's what I proposed in this case. If you increase rates, increase everybody but the small interruptible customers and then give them half the increase you get for the rest.

The other rate design issue deals with this matter of customer charge increases. What the company and I agree on is that we should get rid of the declining block commodity rate and take the revenues you get from those high early blocks and put that in the customer charge. So even if we do nothing whatever in terms of overall revenue recovery, we would be increasing the customer charge as the company wishes. And then I agree that probably if we're going to have a rate increase, we might flow more of that increase into the customer charge than into the commodity charge. But nothing like the enormous increases in the customer charge that the company has proposed.

If we have a rate decrease, which is what staff is recommending, I would recommend that that decrease come entirely out of the customer charge --

I beg your pardon -- out of the commodity charge and the customer charge be left untouched. Well, actually they would be increased because we're flattening the rates, but the revenue recovered from the customer charge plus the early block pieces would not be reduced. We would flow all the reductions into the commodity charge.

On the DDSM, I don't even know whether there's a proposal still, but if it is, I think it's one that should be rejected because of the year's deferral. It could really backfire big time and get us all in a great deal of trouble, because if you had a warm winter and you tallied up a whole lot of money that you ought to collect from ratepayers because you didn't pay very much last winter and this winter it's colder than all get-out and everybody is paying enormous gas bills, both because of the amount of gas they're using and because the price of gas usually goes up when you have a cold winter and then on top of that you hit them with a DDSM charge, it will be very, very unpopular.

If you're going to have a weather normalization program -- I think they're not a bad idea. More and more states are using them. -- they have to be maybe not real-time, but they have to be

concurrent. The warm weather charges that you want to collect from customers have to flow to customers during the warm weather and the cold weather charges that you would to subtract from their customer bills have to be during the cold weather. Otherwise, you are losing the effects, the beneficial effects on ratepayers, which is to even out their year-to-year gas charges.

I think I've said quite enough so I'm going to shut up right now. Thank you very much.

MR. BINEK: At this point I tender the witness for cross-examination.

MR. HOBERG: Thank you, Mr. Binek. Mr. Pearce, if you have any questions.

MR. PEARCE: Yes, I do have several.

CROSS-EXAMINATION

BY MR. PEARCE:

Q. This is just a minor point, but turning to page 2 of your testimony, Mr. King, line 23 and line 27, I suppose you mean gas there. You have electric operation there in both cases.

A. Oh, dear. I'm sorry. That part of my testimony I had simply taken and listed from the earlier.

MR. HOBERG: So you would agree that should

be gas?

THE WITNESS: Yes, it should be gas.

Q. (MR. PEARCE CONTINUING) One of the downsides of word processing, isn't it?

A. That's right.

Q. Exhibit 17, I think, was just introduced and it's electric and gas utilities percent regulated revenue?

A. Yeah.

Q. I think you said you introduced that in the electric case. Dr. Gaske tells me that he introduced that as part of his testimony in the electric case. It's not critical, but maybe --

A. Well, I don't care who introduced it. I thought it was mine, but welcome -- nonetheless, it shows what it shows.

Q. Right. We'll both accept that as true. Now, turning to page 28 in your testimony through 29, I just wanted to clarify a point. It's your testimony that by your understanding Dr. Gaske's 1.625g factor there is based on his assumption that the first dividend would be received three months from the date of purchase; is that right?

A. Well, that's how I calculated it, but Dr. Gaske says that isn't so and I'll let him

explain why it isn't so.
Q. Now, have you -- Dr. Gaske's prefiled testimony, rebuttal testimony is in the record, although it hasn't been introduced as an exhibit. I think you said you had read it; is that right?
A. Yes.
Q. If I could just show you one page, although it's not an exhibit yet, but just to make sure we are on the same wavelength. I'm looking at his JSG-4, page 2 of 3 on Schedule 3. It has the -- I believe what's the classic DCF formula. I just wanted to confirm that we agree that that's the --
A. I think it is, yes.
Q. Okay. Now, turning back to page 20 of your prefiled testimony, and this is the testimony right after your table 7 at the bottom of the page. You say -- in fact, it's the last line of that page, line 22. For example, there are no examples of level or declining earnings in the Value Line forecasts. I'm going to show you --
(Exhibit 18 was marked for identification.)
Q. (MR. PEARCE CONTINUING) Exhibit 18 is a packet of six pages, and before I identify it further, could I ask you -- well, let me back up.
Which issue of Value Line did you use for

your analysis? Do you have that there?
A. Mine are all dated June 21.
Q. Of 2002?
A. Yeah.
Q. Okay. Now, looking at what's been marked as Exhibit 18, it is -- and I'll tell you what it is, is sheets from Value Line for six companies of that same date. Would you agree that's what it appears to be?
A. Yeah. None of them are the six companies that I was analyzing.
Q. Right. Right. No.
A. Or the 11 companies.
Q. You make in your testimony a very broad statement about Value Line. I just wanted to lead you over to some other companies that were not in your testimony.
A. Well, I didn't mean to imply that they never, ever predict declining earnings. I was talking about among the 11 companies that I was looking at.
Q. Okay. Just to go through this, looking at these companies, and I realize this is very fine print for a person of my age, but looking at the third line there, earnings per share, and then down

toward the bottom is return on common equity, I think. Would you agree if you have a chance to look at each of these six sheets, that there is, in fact, declining earnings and earnings per share from 2000 -- between 2000 and 2001 and, in fact, out through the 2005, 2007 period?
A. Oh, sure, for these companies. These are in the oil business. I don't know what Holly Corp is. Crude oil. We're looking at oil companies for some reason.
Q. I believe they're all energy companies.
A. Tesoro is one of them.
Q. Right.
MR. HOBERG: Are you offering Exhibit 18, Mr. Pearce?
MR. PEARCE: Yes.
MR. HOBERG: Any objection to 18, Mr. Binek?
MR. BINEK: Well, the only objection I would have is based on the comments that Mr. King has made, that none of the companies that he's talking about are included here, and so I guess I would question the relevance of this.
MR. HOBERG: What is the relevancy, Mr. Pearce?

MR. PEARCE: The way the testimony is written the implication appears to be that all of Value Line's companies that it analyzes are overly optimistic and there's never any report of declining earnings and we simply wanted to show that although -- that without regard just to utility companies, as a general principle, that's not true for Value Line generally.
MR. HOBERG: Do you have any objection for that limited purpose, Mr. Binek?
MR. BINEK: No, I guess that's okay.
MR. HOBERG: I'll admit Exhibit 18.
MR. PEARCE: That's all the questions I have.
MR. HOBERG: Thank you, Mr. Pearce.
Commissioner Reinbold, did you have any questions of Mr. King?
COMMISSIONER REINBOLD: Yes, I do.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. Mr. King, you said something about heat pumps wouldn't work in this part of the country in North Dakota?
A. That's what I've been told. I'm not an engineer and I can't really testify as an expert on

that subject.
Q. Would it surprise you if I directed you to a window in this room and directed you to look to the northwest and see a brand-new huge church building which is being heated and cooled by 120 wells 160 feet deep in the parking lot?
A. Goodness.
Q. Doing it very efficiently. A young entrepreneur, who was a well driller, got it started and he's worked this type of work as far away as South Carolina. So it may not work everywhere, but it does work over at our church. It's very expensive and it will be expensive for a long time, but it does work.
A. I hope you're comfortable at Christmastime.
COMMISSIONER REINBOLD: That's all I have for now.
MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.
COMMISSIONER WEFALD: Yes, I have a few questions.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. On page 34. I understand there's a disagreement between the company and the staff about

whether short-term debt should be included and as you've said, it's only 2.78 percent that you've included in your calculations.
A. That's right.
Q. And you're asserting -- my first question is, are you asserting that short-term debt should be included?
A. Yes.
Q. Because you have information on the record and where is that that shows that they're using short-term debt?
A. Well, you never know. You can't trace the source of money from where they get it to where they use it because it all goes in effect into the bank account and then back out again. But the proposition is that when you have expenses that fluctuate -- or capital costs or expenses that fluctuate, particularly capital costs fluctuate month to month, the normal way of financing those would be through short-term debt. Now, they are high in June and low in January and where are you going to get the money to cover those, you go to the bank and borrow it.
Now, in fairness, MDU does not use much short-term debt. And the reason is that the company

generates a lot of internal cash primarily from excessive depreciation charges, but that's what Mr. Majoros is going to talk about. But they do use some, and this is what I reflect here. And the reason I put in this exhibit is to show that there's significant variation from month to month in the working capital.
Q. How did you come up with this?
A. It's from the company's own -- well, the numbers are presented up in the front. Let me find the table for you. It's page 5.
Q. Yes.
A. Table 1.
Q. But I just wondered how you were able to determine it was $9,639,000 --
A. That I think I got from there --
Q. -- if you said it's hard to trace?
A. Oh, you can determine how much short-term debt there is. What you can't do is determine where they spent it. That's what I meant is hard to trace. I believe I got that -- here it is. Look at my Exhibit CWK-1, which is attached to my testimony.
Q. Okay.
A. Go to the last page of that exhibit and

there at the bottom you'll see the 9 million and you'll see the 4.542 percent. That's the source of those numbers. And this is a company data response.
Q. All right. And on page 43 of your testimony you talk about penalties for failure to interrupt should be increased, on line 11.
A. Yes.
Q. Do you have any recommendations about that?
A. Well, I was going to recommend the company's proposal be accepted. And it's the company's judgment as to what it takes to make interruptible customers interrupt, but if they don't interrupt, you could have a disaster. You can have the pipeline suddenly unable to deliver gas to the city gate and everybody goes cold. So if -- and the company isn't planning. They don't make the commitment to the pipelines. They don't build their own main structure to handle the interruptible customers' loads at the peak day. The assumption is when it really gets high gas demand, phone them up, have them cut off. They don't cut off, the company can be in trouble.
Q. Right.
A. So I think it's very important that there be sufficient pricing to persuade those customers

they better interrupt.
Q. Well, what I was wondering is, it says here, penalties for failure to interrupt should be increased since the company apparently believes that the current penalties are not sufficient. So did the company present what you feel is a sufficient penalty then to --
A. Well, I really do have to defer to the company. I guess I accepted their judgment in that regard. Maybe I'm naive, but in this regard I --
Q. You're not disputing what they're proposing?
A. I'm not disputing their judgment on that. But I think if you want to know what is the basis of the exact amount of increase, you better ask Ms. Aberle.
Q. All right. Then my next question was page 44. This is under the question, have you calculated the increased customer charges that would result from eliminating declining block rates. It's my understanding that you think that we should be eliminating the declining block rates. And so is it your recommendation that this size increase that is reflected in paragraphs 19 through 23 is what should be put in place for customers?

A. Well, what I did in my Exhibit CWK-8 was calculate the revenue that is recovered in the high initial blocks of the present rate structure. And then I divided that by the number of customer bills and got the amount of increase you would need in the monthly customer charges in order to recapture that same money in the customer charges instead of in the initial declining block rates. And that's the numbers you see here. This is a totally revenue neutral proposal.
Q. Right. I see. This doesn't reflect any increase that the company may want?
A. No increase, right.
Q. This is just what would occur if you eliminated the declining block rate?
A. Right.
Q. So then this would be the minimal amount -- this would be the bottom amount that we would be looking at --
A. Yeah.
Q. -- for a customer rate increase before you'd --
A. Yeah.
Q. -- project any -- if you were going to do any increase for their rate case?

A. Right. What I'm suggesting is, even if you reduce rates, you ought to keep these customer charges, because I am sympathetic to the company's desire to capture somewhat more fixed costs in the customer charge. So I think if you were to reduce the rates, it would be inappropriate to reduce the customer charge. Reductions ought to come out of the commodities.
Q. Even in this situation for the large customer who goes from $17 to $45, which is a triple increase?
A. It's a big increase, but it is, as I believe an earlier witness pointed out, those customers use so much gas that this is small potatoes in terms of their total bill.
Q. All right. And then on page 45, the question is, are there any other proposals the company has made that you believe the Commission should consider regardless of the change in overall revenues, and your answer is on lines 12 through 19. I recommend the Commission consider the company's proposal to convert the basic service customer charge from a monthly charge to a daily charge. And then you go on and then you say. My only concern is whether it might be accepted by the average customer

as a reasonable way of charging for service.
To me it would be very confusing as a customer to not know every month, not to have the same amount each month on my bill for my customer charge.
A. Yeah, and I'm sympathetic to that. I think that's a legitimate concern and that's why I put that sentence in there. I guess I'm tossing the ball back to you as to whether you think that is something that will go down with the average customer.
Q. Because, otherwise, you might have one rate that would be there for the 28-day month, another one for the 30-day month and another for the 31?
A. You get a lower customer charge in February, right. But I think the virtue from the company's standpoint is it gives them a little more flexibility as to when they send their meter readers out. Now, it's got to be -- I guess I don't know whether they bill by the calendar month or whether they bill -- each customer get from a certain day to a certain day, but whatever it is, they're locked into pretty much a 30-, 31-day interval and this would permit them to alter the interval, if they had to.

Also, we put in a data request asking how many customers did they have that had partial month bills in a given year, and it was a huge number. I don't know why, but it was -- I was surprised by how big it was. And it's one of the reasons that I sort of gave a backhanded endorsement to this proposal. But it's certainly not something that I would insist on.

Q. When you say -- what do you mean by a partial month bill?

A. What we asked was in any given -- I don't have the data response with me. They had said they had a lot of customers who came -- who got on and off during the year. And the consequence of signing on for a part of a month instead of the full 30 days, they had 20 days or 10 days or whatever. And I said, all right, well, how big a deal is that? How often does that occur? And it was in the thousands. It was quite remarkable that it was as much as it was. Evidently, there must be a lot of customers who simply turn off gas service in the course of the year and disconnect. And then reconnect later. It could be vacation homes or people who decide they don't need gas in the summer because they don't need the heat in the summer and

they cancel gas service. You have to ask the company why it's so large, but it was a large number. And this would facilitate dealing with that problem.

Q. I will ask the company a few more questions about this, but then does it also -- in your understanding of this does it reflect -- let's say the company read my meter on January 15 and then they didn't get around to reading my meter again until the 20th of February. So then there might be -- would I get a 30-something day --

A. Thirty-five-day month, it's possible.

Q. And then the next I get a 25-day one if they went back and did it again on the 15th again of the next month?

A. If you're like me, you write your bills once a month when you get paid, and customers could really get messed up if they started changing the -- if they got out of the monthly cycle of billing, which this would permit them to do. So maybe that's a good reason not to permit this change.

COMMISSIONER WEFALD: Who would be the MDU person I would ask these questions of just so I can understand it better?

MR. HOBERG: Mr. Pearce?

MR. PEARCE: I suppose probably Mrs. Aberle.

MR. HOBERG: Tamie Aberle.

COMMISSIONER WEFALD: I do have some questions about that so I will ask Ms. Aberle.

Q. (COMMISSIONER WEFALD CONTINUING) All right. And then, now, this is a bigger, broader question.

A. I like big, broad questions. I give big, broad answers.

Q. So now let's say a hypothetical utility has divisions and one of them makes -- one of these 11 divisions that they have and only one is a utility division, but it's still a -- it's a company with many subsidiaries, and one is the utilities and one of those divisions makes bad business decisions and starts to go into a -- close to a bankruptcy situation. So within the -- it's my understanding what happens sometimes then is that the bond rating of the whole company can get lowered and then a Commission has to worry about what are the -- whether the riskiness of their bond rating at that time is going to be passed on to their customers.

When you're talking about looking at bonds for the whole group of MDU companies, all of these

divisions, if I accept your premise that the bonds are good for everyone and it's the whole, big company that has a bond rating and not just one division, am I setting myself up in the future then to set precedents that if they make a bad decision with one of their divisions, that I'm going to need to accept that bond rating for the utility company as well?

A. Well, you have exactly that situation with your telephone company.

Q. Right.

A. And it's a difficult problem. US West was a thoroughly successful company, but it got bought by this Qwest outfit, which has gone south, and it's junk bond status. And your question is, okay, what are you going to do about assigning a bond yield cost to US West?

Q. Well, and I don't have to worry about that because under price cap, but let's say there's a hypothetical company that's in the same situation, but we know that that's reality in some cases today. And so what I'm concerned about is your --

A. Well, what I would say is that if the utility piece of it is a -- is profitable and would support an adequate bond rating, then for -- but the

rest of the company caused it to go south, I think you would have to impute a bond cost that reflected the utility's performance. Fortunately, for MDU Resources that's not an issue, because not only is the utility profitable, but the parent company is also profitable.

But I think your concern is a very legitimate one, that if the non-utility activities of the company soured the bond ratings such that there were astronomically high debt costs, is it fair to ratepayers to pass those debt costs through to them? And I would say no, because that is a result of -- it's in a way analogous to why we don't use MDU's equity costs because its equity cost is seriously influenced by its nonregulated activities. If you could demonstrate that the bond -- the debt cost is influenced adversely by the nonregulated activities, then I think it's appropriate to impute a different debt cost. Fortunately, I don't think that's an issue here because it's clear that the company seems to have a good debt rating.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commission Clark, please.

COMMISSIONER CLARK: I have none. Thank

you.

MR. HOBERG: Thank you. Any further questions of Mr. King? Mr. Binek?

MR. BINEK: Just one.

REDIRECT EXAMINATION

BY MR. BINEK:

Q. I guess I would like a little bit of clarification about this heat pump business. When you were making reference to the use of heat pumps, you were -- I'm assuming you were thinking about a unit that does both heating and air conditioning, kind of a stand-alone unit, versus something that draws heat off of groundwater?

A. Yeah.

Q. Is that correct?

A. Mr. Majoros can testify about heat pumps. He has one in his house and he says he hates it.

Q. Okay. But there are different kinds of heat pumps?

A. Yes. Essentially, it's an air-conditioner that works two ways, and it only works as an air-conditioner in the reverse direction down, I'm told, to about 45 degrees Fahrenheit. If it get colder than that, you have to supplement with resistance, electric resistance heating, which is

why it becomes very expensive if you have a cold climate, because up here you would have that resistance heating on all the time and that scarfs up an incredible amount of electricity.

Q. These are the kinds of units that we often see in motels; isn't that right?

A. Yeah.

MR. BINEK: Okay. No further questions.

MR. HOBERG: Thank you, Mr. Binek. Mr. Diller, any questions? Okay. Anything further then of Mr. King? Thank you, Mr. King.

Let's take a short break and then we can perhaps take Mr. Majoros and finish off the day that way. Let's be back at -- a five- to seven-minute recess.

(Recess was taken.)

(Exhibits 19 and 20 were marked for identification.)

MR. HOBERG: We're back from a short recess. And, Mr. Binek, you were ready to call your next witness.

MR. BINEK: Yes. I will call Michael Majoros.

MR. HOBERG: Mr. Majoros, you were here earlier when I gave the admonition regarding

perjury; is that correct?

THE WITNESS: Yes, sir.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Binek, please.

MR. BINEK: Thank you.

MICHAEL J. MAJOROS, JR.,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BINEK:

Q. Would you state your full name for the record, please.

A. Yes. My name is Michael J. Majoros, Jr.

Q. What is your occupation, Mr. Majoros?

A. I'm vice-president of the economic consulting firm of Snavely King Majoros O'Connor and Lee, Incorporated.

Q. And how long have you been at that firm?

A. Approximately 22 years.

Q. What is your educational background?

A. My educational background is in accounting. I've passed the CPA exam, taken courses in the MBA

program at George Washington University, and have taken several continuing education courses.

Q. And you have testified in a number of state commission utility rate cases?

A. Yes, sir.

Q. You have before you documents Exhibit 19-49, I think it is, and Exhibit 20. Could you please identify those two exhibits?

A. Yes. Exhibit 19-49 consists of my testimony, my Appendix A, which is a summary of my qualifications and experience, and my Exhibits MJM-1 through MJM 12.

Q. And what is Exhibit 20?

A. Exhibit 20 is a packet of exhibits I prepared in response to primarily Mr. Jeter's rebuttal to me.

MR. BINEK: At this time I would offer Exhibits 19 and 20.

MR. HOBERG: Mr. Pearce, any objections to Exhibit 19?

MR. PEARCE: No.

MR. HOBERG: How about 20?

MR. PEARCE: No.

MR. HOBERG: Exhibits 19 and 20 are admitted.

Q. (MR. BINEK CONTINUING) I should have asked, if I were to ask you the same questions today that are in your testimony, would your answers be the same?

A. Yes, sir.

Q. Are there any errors in your testimony that need to be corrected?

A. I noted a couple of typos, but the one that I would like to correct is on page 5, line 5. There's a range of years in that sentence, 1996 to 2000. I'd like to change that to 2003.

Q. Any other corrections?

A. No. No, sir.

Q. At this time I would ask that you please provide a summary of your testimony and also provide any response that you may have to rebuttal testimony that has been filed by Montana-Dakota Utilities in response to your direct testimony.

A. Okay. The objective of my testimony is to recommend the appropriate jurisdictional revenue requirements for the North Dakota gas division of Montana-Dakota Utilities, Incorporated. I've attempted to recognize the legitimate needs of the company to recover its costs, but at the same time I've attempted to ameliorate any added burden on

ratepayers from excessive recoveries. Ms. Mulkern proposes a $2.8-million base rate increase using an 11.44 percent rate of return. I recommend a $1.4-million base rate decrease using Mr. King's recommended 7.98 percent rate of return. My adjustments are summarized at page 3 of my testimony.

I propose to reduce the Company's depreciation rates. I propose to eliminate bonuses and commissions from the company's costs and hold the 2003 labor cost levels equal to the 2002 levels. I propose to eliminate the SISP from benefits expense. I propose a five-year rather than three-year rate case amortization period. And I propose to eliminate the general inflation from other unadjusted operation and maintenance expenses.

At pages 4 to 7 of my testimony I've included certain financial analyses. At the top of page 4 of my testimony I demonstrate that the company's gross margins declined from 2001 to 2003. The decline is caused by major increases to operation and maintenance expenses, excluding the cost of gas. Increased O&M expenses is a major driver in this rate case. From 1996 to 2003 O&M expenses, excluding the cost of gas, increased at a

compound rate of 2.5 percent. And that is shown on my Exhibit MJM-2. However, that 2.5 percent is slightly misleading because from 2000 to 2003 the expense is actually ratcheted up and continued on from there. The compound growth rate from 2000 to 2003 is actually 5.7 percent, which, in my opinion, is unreasonable.

I am also recommending a change in depreciation rates. Since depreciation produces cash flow for this company, I conducted certain cash flow analyses. Although depreciation is not intended to finance capital additions, some equate it to additions as if that was its intent. As I stated in my testimony, the purpose of depreciation is not to finance plant additions. Nevertheless, I've determined that this company's depreciation seems to always produce more than sufficient cash flow to cover its additions.

At page 6 of my testimony I've included a table of -- comparing annual depreciation cash flow to annual construction additions at the total company level for the years 1996 to 2002. Mr. Jeter challenged this table so I've provided an expanded table, which is the first page of Exhibit 20. Even with the revisions --

COMMISSIONER WEFALD: Where is Exhibit 20, please?

MR. HOBERG: That's the one that was just introduced, that separate one.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: Even with Mr. Jeter's changes, at the total company level since 1996 this company's depreciation expense has exceeded its capital additions by $409,000. I also -- Mr. Jeter also challenged my Exhibit MJM-3, where I compared the gas utility only depreciation expense to additions. Mr. Jeter claimed that I failed to include common plant depreciation expense in column 2. Consequently, on the third page of Exhibit 20 I've made the adjustment in accordance with Mr. Jeter's testimony. And what this demonstrates is that since 1986 this company's gas company North Dakota depreciation expense has exceeded the additions to gas plants in North Dakota by $8.2 million. In my opinion, this has resulted from excessive depreciation rates which have been charged to ratepayers.

At page 7 of my testimony I cite and quote from what I consider to be a landmark U.S. Supreme Court decision on the subject of depreciation.

COMMISSIONER WEFALD: That's where?

THE WITNESS: Page 7 of my direct testimony.

COMMISSIONER WEFALD: Page 7. Thank you.

THE WITNESS: In that case, which is known as Lindheimer v. Illinois Bell, the Court equated excessive depreciation to the extraction of capital contributions from ratepayers. And it clearly stated in the beginning of the second paragraph, Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. This morning I heard the word "confiscation" from Mr. Gaske, and I understand the company in this case has the burden of proof. And my testimony states that their depreciation expense is excessive, and I provided my reasons for making that claim.

Here's how I arrived at that conclusion. First, I reviewed this company's depreciation reserve levels and that's accumulated depreciation. I have testified or been involved in more than 80 proceedings on the subject of public utilities depreciation. Based on my experience, if you refer to page 9 of my testimony, the 70.7 percent reserve

ratio for the distribution plant is very, very high. And it suggests that prior depreciation rates may have been excessive. I asked the company if it conducted any studies to measure the adequacy of that reserve and it has not. The company's current depreciation rates are based upon an 11-year-old study conducted by Stone & Webster, which does not exist anymore, at least Stone & Webster doesn't, to the best of my knowledge.

That was the next place I looked. I've included as MJM-4 to my testimony the first few pages from that Stone & Webster study. These are also included in the company's Statement I, if I could refer you to those pages. Two things caught my eye in reviewing this. The first thing that caught my eye was the negative 140 percent net salvage ratio for services. That is shown in about the fourth column. It says estimated retirement costs percent amount.

COMMISSIONER WEFALD: Will you just show me what you're looking at?

THE WITNESS: I'm looking at Exhibit MJM-4, page 1 of 2.

COMMISSIONER WEFALD: MJM. Thank you.

THE WITNESS: About halfway down -- well, a

third of the way down the page, account 380, the second number in that line is negative 140. And that's a very, very high negative net salvage ratio. That also suggested to me the possibility the current depreciation rates are excessive.

The next thing that caught my eye, if you come over three columns, the column that starts with the number 39 and then goes to 36, those are average service lives. The average service life for distribution mains, which is the single largest account on the company's books, is 36 years. If you put a circle around that, and then coming down the page, the average service life for services, which is the second largest account, is 34 years. Based on my experience with gas companies, those are very, very short lives. Short lives equate to high depreciation rates. If they're too short, the resulting depreciation rates are excessive.

Consequently, I conducted certain tests of those lives based upon the information available to me. These are called geometric mean turnover analyses. They're included as Exhibit MJM-5. And these two analyses would indicate that overall the average service life for mains is in the 108-year range and the average service life for services is

in the 69-year range. Mr. Jeter, through a data request, identified certain discrepancies in my calculations. So I redid the GMT studies. They're included again with Exhibit 20. And when I make the adjustments identified in the company's data request, the corrected GMT studies would support lives for mains of 116 years and lives for services of 74 years.

At this point I'm pretty convinced that the company's depreciation rates are excessive. I conducted one more analysis based upon the company's data request to me. This, I must admit, was after I had filed the direct testimony. It's contained on page 2 of Exhibit 20. And here I've compared the company's current average service lives to industry statistics.

COMMISSIONER WEFALD: You're on which page?

THE WITNESS: Second page of 20.

COMMISSIONER WEFALD: The second page?

THE WITNESS: Yes. And I obtained these statistics from the AGA/EEI. They are proprietary and confidential so I've only summarized them here. But if you look at, again, mains, the company's average service life is 36 and you look across that line and it's basically much lower than the industry

averages. And services is about five to six years lower than the industry averages. Given all that, I mean, I could have recommended longer lives, but I did not because there's a bigger issue in depreciation.

As I indicated, I'd like you now to go back to 4, Exhibit MJM-4. On that first page you can see at the bottom of the page where it says total depreciable plant, the first column is, of course, the description of the plant accounts. The next column is plant balance, and the next column is the cost of removal or the negative net salvage that's incorporated in the current depreciation rates. And that happens to be $46.5 million. Now, that's the total estimates back at that time. That, again, is about almost 50 percent of the total plant balance. What that means is, that in calculating those rates, those depreciation rates, an additional 50 percent was added to the plant balance in order to collect 150 percent of the plant balance.

So -- and that might be reasonable. I did some more investigation. And what I discovered -- I'm going to point you again back to that 140 percent for services, because that is a huge rate, and the resulting depreciation rate of 8.22 percent

is the highest rate I think I've personally seen for a gas service account. It's way -- very much higher than normal. So I asked for the company's actual net salvage data and what I discovered is shown on my Exhibit MJM-6. And what that shows --

COMMISSIONER WEFALD: Just one moment, please.

COMMISSIONER REINBOLD: What are we looking for?

COMMISSIONER WEFALD: MJM-6.

THE WITNESS: MJM-6. What that shows is that on the gas side, the total net salvage for the years 1997 through 2001 was 1.4 million.

COMMISSIONER WEFALD: Where do you see that?

THE WITNESS: Where it says total under net salvage, natural gas.

COMMISSIONER WEFALD: Okay.

THE WITNESS: But what's really extremely interesting about that number is it's positive and the company is collecting for negative net salvage to the tune of about $2,000,000 a year in its current depreciation rates. Furthermore, in doing this investigation, I discovered that there apparently was a sale of a building in 2001 which

produced about 4.9 million, a 4.9-million gain that was a common plant. And the company included that also as positive salvage.

Now, Mr. Jeter wrote many, many, many pages of testimony rebutting me, but he never addressed this threshold issue, which is that the company's current depreciation rates are charging ratepayers about $2,000,000 a year for negative net salvage when the company normally experiences positive net salvage. And that difference is, in my opinion, even with the lives which I know are much too short, but that overcollection is what produces the excessive depreciation reserve levels.

I talked in my testimony about a certain new accounting requirement, Generally Accepted Accounting Principle. First of all, the acronym for that is GAAP, G-A-A-P. And I readily admit that GAAP does not control ratemaking. But what I find interesting about SFAS No. 143 are the principles which underlie it, and I believe they make sense and I'm just recommending to you to consider those principles. The principles are fundamental. Before you include any cost in today's cost for some future potential expenditure relating to the removal of a plant or mass property plant, you have to establish

a legal obligation to incur that cost. Otherwise, that cost will just be expensed as incurred, rather than used to inflate depreciation rates.

Now, Mr. Jeter has included a lot of testimony about how to implement FAS 143, but he failed to focus again on the fundamental issue, which is does this company have asset retirement obligations, those legal retirements. And the answer is based upon all of the responses that were submitted to me is, the best answer is they don't know, but I think the most likely answer is no, based on what I'm finding out in other states and in other proceedings. The natural gas industry does not have asset retirement obligations for distribution plant. And if they do, they're rare. There are some unique circumstances involved.

So what's going to happen as this company is subject to SFAS No. 143, just like all companies in the country, regulated and unregulated. And what's going to happen is that on their nonregulated books when SFAS No. 143 is implemented, all of that excess depreciation which is included in the distribution plant reserve reflected by that 70 percent is going to be pulled out of that reserve and treated as a regulatory liability to ratepayers.

So the company has said they are going to do -- they recently embarked on a new depreciation study. I don't know how that's going to be treated there. My suspicion is, you know, if I were involved in that study, I'd say for ratemaking purposes, perhaps you ought to use the remaining life method which will amortize that excess back to ratepayers over the remaining life of the existing investment.

But what I've done for the purposes of this rate case, since clearly their current depreciation rates are excessive as a result of this negative net salvage is, I've merely eliminated from the existing depreciation rates. I haven't changed any of the lives or anything like that. I've just stripped out the negative net salvage and said let's collect that, the average of that on sort of a normalized expense basis. This is a procedure that is used in Pennsylvania regularly. It's been recently approved in two cases in Kentucky. In my opinion, it is consistent with the likely result.

COMMISSIONER REINBOLD: With what?

THE WITNESS: It is consistent with the likely result of the implementation of SFAS No. 143, combined with another statement of accounting policy on property plant and equipment. It keeps the company whole. It keeps ratepayers whole and it removes this excessive recovery from current depreciation rates. I talked a lot about depreciation because, of course, it's the biggest adjustment in my testimony.

I'm also recommending the elimination of wages and bonuses. I'm recommending the elimination of the supplemental security income plan. I'm recommending a five-year rather than three-year rate case amortization period, and the disallowance of inflation to other O&M expenses.

That concludes my summary.

MR. HOBERG: Mr. Binek, did you have some questions?

MR. BINEK: Yes. I just have a clarification concerning the statement about elimination of wages and bonuses.

Q. (MR. BINEK CONTINUING) When you talk about the elimination of wages and bonuses, what -- is it your recommendation that the -- you eliminate the 2003 increases as an expense in this proceeding? You're not telling the company that they can't give raises or bonuses, if they want to, it just should not be charged to the ratepayers?

A. That's correct. Elimination from the rate

case.

Q. Right.

MR. BINEK: Okay. At this time I'll tender the witness for cross-examination.

MR. HOBERG: Thank you, Mr. Binek. Mr. Pearce, please.

MR. PEARCE: Thank you.

CROSS-EXAMINATION

BY MR. PEARCE:

Q. Mr. Majoros, I may have misheard. I was a little alarmed when you said elimination of wages. I don't assume you mean all wages to employees should be taken out of the rate case?

A. Not all.

Q. Now, to clarify a point that may be misleading, you talked about the Lindheimer, Illinois Bell case and cited the Court's reference to confiscation being the issue. What the Court is talking about, isn't it, is that Illinois Bell alleged that its property was being confiscated by exceptionally low rates? It isn't a matter of the other side claiming that the depreciation rates were confiscatory?

A. Well, I believe you're probably correct, but the words stand on their own.

Q. Yeah. It's sort of a pejorative word. I just didn't want it to be taken out of context.

A. But I heard that word this morning. That's the only reason I brought it up.

Q. Turning to your Exhibit 20, and this is page 1 of 4 of MJM-5, which is your geometric mean turnover analysis for the mains account. You described your technique using the geometric mean for a life estimate there and, of course, a geometric mean uses a product of two ratios there, doesn't it? You take the square root, of course, the usual way the geometric mean is done. That technique means -- now, for example, if you -- looking at, say, 1996, for example, if you substituted; that is, interchanged columns C and D, the additions and retirements, you'd have the same result, right, because they both appear as numerators in effect in that calculation so it doesn't matter how you take them? In other words, you would get the same lifetime if you had single-year retirements of 119 -- I mean, single-year additions of 119,000 and single-year retirements of 1,096,000, you interchange columns C and D, is what I'm saying and you get the same number?

A. Yes.

Q. You referred to Stone & Webster as nonexistent. Now, you're not suggesting, are you, that they were not in their day a highly reputable and very large company?

A. I just -- when I talk about them, I'd like to be looking at their study. Yeah, they were a large company in their day.

Q. For whatever reason, I believe they have, in fact, disbanded or disappeared. You have not done an actual depreciation study, a full study comparable to their 1991 study, have you?

A. You know, I'm not really sure of everything they did in that study. I know what they said they did. I've tested the lives of the two largest accounts in the company's books, and if I could refer you to the Stone & Webster study, I have it here before me. I'll just refer you to page 4. I used the geometric mean turnover approach to test that. And in the Stone & Webster study they say in the second paragraph, quote, The turnover testing is a procedure in which the adjusted turnover period, i.e., the number of years it takes an investment in plant to be retired, is determined by aggregating additions from the year 1991 backward until the total is equal to the plant balance in that year and

then adjusting for the rate of growth in the account.

So, you know, turnover method is not new. Other firms have used it. And I'm not recommending any changes in service lives.

Q. You're not suggesting the way you characterized it a moment ago that Stone & Webster didn't actually do what they said they did?

A. Well, I don't know how they arrived at the negative 140 percent for services and you can't tell from that study.

MR. PEARCE: Okay. I don't have any other questions.

MR. HOBERG: Thank you, Mr. Pearce.

Commissioner Reinbold, did you have any questions in there?

COMMISSIONER REINBOLD: Just a couple. Thanks.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. I lost track of something here. The 1991 Stone & Webster survey, what was the point that you were making about that?

A. Well, the first point is it's 11 years old. The second point -- the point I just made was, they

apparently employed one of the very procedures that I've used here to test lives in that study. And the reason I bring that up is because Mr. Jeter and now Mr. Pearce have sort of implied that I haven't done any kind of complete study, whether it's -- you know, given the level of available data, the use of the geometric mean turnover approach is as legitimate as any other approach.

Q. Okay. Turning to your reference to selling a building, can you flesh that out a little bit?

A. Yes. There apparently was a building sold in 2001 and it produced a gain of about $5 million. And the company debited cash, put that money in cash and credited it to accumulated depreciation. Now, if that building was included in rate base, which I imagine it probably was, that gain probably ought to be shared with ratepayers. By using the company's approach here, you would not have known about it until I found it.

Q. I understand now.

COMMISSIONER REINBOLD: That's all.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

COMMISSIONER WEFALD: Yes.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. On page 5 of your testimony you say the compound growth rate from 2000 to 2003 is 5.7 percent and you have a chart, an exhibit that reflects that. I think it's Exhibit MJM-2.

A. That's correct.

Q. Okay. What specifically do you think is driving this?

A. I think that commissions and bonuses and the SISP and the imputation of inflation in year 2003 are driving this.

Q. On page 10, why are the company's depreciation reserves so high? I need to have you help me with this. It's negative 140 percent factor on line 8, which means that the current depreciation rates for service was substantially increased to recover not only the existing investment, but also another 140 percent for future costs of removal?

A. That's correct.

Q. So I just need an example here. When they put in a gas main, the current depreciation rate is -- according to your understanding, it doesn't recover not only the existing investment to the main, but another 140 percent for future cost of

removal of the main?

A. Here I'm talking about services, which --

Q. Services.

A. -- is from the main to the house. And if it costs $1,000 to put that service in, its depreciation rates were designed to collect $2,400, which was the original cost plus another 140 percent for future cost of removal.

Q. What do you -- if you have looked at other depreciation studies, what would you say would be a more normal future cost of removal?

A. Well, typically, that number is driven, based from my experience, is typically driven by some internal cost allocation policy in which the cost of removal is -- you know, they have to figure -- when they go out and replace a main and a service, they have to figure out how much of that cost they want to assign to cost of removal. So they come up with an allocation factor, which results in that allocation.

I explained in my testimony here about Elizabethtown Gas. This was just, you know, within the last two months where I went out and watched a typical main replacement project for that company. And what I discovered in watching and observing that

project, was that the replacement of an existing service, first of all, is very rare. It's a --

Q. You mean the part from the main to the home?

A. Right.

Q. That's the service?

A. That's the service. Because what they do is, they'll have a main running down a street and want to replace that main. They will trench a couple of feet away and a lot of times they will keep that existing service. They may insert something into it to maintain, but it's rare that it actually gets removed. So the replacement cost is just the cost for disconnecting from the original main and then extending another tap over here.

So, in my opinion, that cost is really a replacement cost and probably ought to be capitalized to the new main or something like that. So it's difficult to answer your question about what is a typical removal cost. It depends on how a given company allocates that cost. What's important to understand about this particular company is they don't record any cost of removal at all for services. They're collecting 140 percent, but not recording any cost of removal, as difficult as that

is to believe.

Q. They're not reflecting any cost of removal where?

A. No cost of removal in their books and records. I went through their summary tables and I can see some cost of removal for mains. I could see -- I was looking for account 380, services, and it's not there. They're not recording any -- as big as that number is, you would think that that would certainly be one of their recurring costs of removal, they would record it, and it's not there.

Q. So does that suggest to you that they're not having any --

A. I don't think they do.

Q. -- costs of removal?

A. I speculated in my testimony and Mr. Jeter took, you know, a shot at me, but what I found out in the Elizabethtown Gas case is that for years and years and years that company and probably most gas companies, the people in the fields never recorded costs of removal. They treated everything as a service transfer expense and just expensed it.

Q. All right. Now I want to go -- all right. Now, I want to understand MJM-4.

A. Yes.

Q. You said another --
COMMISSIONER REINBOLD: What page is it on?
COMMISSIONER WEFALD: MJM-4. It's in the back of his testimony here. Page 1 of 2.
COMMISSIONER REINBOLD: Okay.
Q. (COMMISSIONER WEFALD CONTINUING) Now, on this one you said another 50 percent was added to the total depreciation plant.
A. Yes.
Q. That's down at the bottom.
A. Yes.
Q. I need you to lead me through that again.
A. First, the third column is plant balance.
Q. Right.
A. Okay. I always go back to services because it's the best example of this.
Q. It shows a negative in front of that 46. What is it, 46 million?
A. That's at the bottom. I was trying to lead you to how I got to that number.
Q. Okay.
A. So if we look at services, the plant balance is $200,727,046.
Q. All right.
A. The company applied a negative 140 percent

salvage ratio to that to come up with an estimated future negative -- future cost of removal of $28,101,844. It added that amount to the plant balance to arrive at something called the estimated service value, which is $48,174,590.
Q. Where is that number?
A. That is under a column titled estimated service value.
Q. All right.
A. Okay. It then divided that estimate service value over the estimated remaining life of 21.8 years. That's about the third from the last column.
Q. Yes.
A. To come up with an annual accrual amount of 1.6 million, which in turn produced an annual depreciation rate of 8.22 percent, which is then applied every year to calculate depreciation expense and, in fact, the company applied that rate to services in this case and, of course, the plant balance -- this was the 1989 -- 1991 plant balance. That has increased, I believe, substantially. So in this case, the recovery is more than that.
So, anyway, going back to that column where they've applied the 140 percent, they also applied

negative 40 to mains and then they have some positives offsetting it, but the sum of all those positives and negatives sums to negative 46,495,732, which, again, you can see has been added to the plant balance to arrive at that estimated service value, which is then being depreciated.
Q. All right. Thank you. All right. Then go to MJM-6.
A. Yes.
Q. Now, you made the point and I just -- is this what you said, that MDU is charging customers negative net salvage when the company has a positive salvage value?
A. Yes.
Q. So the $2,733,666, tell me about that number again.
A. What I've done there is you'll notice I've separated the plant into electric, natural gas and common utility.
Q. Yes.
A. The common utility I didn't know exactly how to allocate that back to the electric and natural gas, so what I did was allocate that 5.5 million back to electric and gas based upon the totals right above that, you know, the 1.412 and the

1.44. The sale of the building is included in that common utility plant column. I mean, the gain on the sale of the building.
Q. The sale of the building is included in which column?
A. Common utility. It's the first big number on that, over in the right-hand column, the 4.889 million.
Q. I'm somehow missing that.
A. All the way to the right.
Q. All the way to the right. I'm seeing the number -- am I looking at the correct number under common utility, 5,529,260?
A. Right. At the top of that column.
Q. All right.
A. That's the gain on the sale of the building.
Q. Oh, that 4,889,037?
A. Yes.
Q. Okay. Then I need you to go to MJM-1.
A. Okay.
Q. And this gives -- page 2 of 4.
A. Yes.
Q. This goes over the numbers. You're contrasting your numbers to the company's numbers

and its income statement?
A. Yes.
Q. And at the present time, let's skip over the operating revenues --
A. Okay.
Q. -- because those are the same?
A. Yes.
Q. And then you go down to the operation expense, and there isn't a difference in your cost of gas, there's a slight difference in your other O&M?
A. Yes.
Q. But the big difference then comes when you get to depreciation?
A. Yes.
Q. And the company is projecting in 2001, 2002 and 2003 over $3 million, but let's use the 2003 figure because that's the one you're looking at also.
A. Mm-hmm.
Q. Is that correct, $3,261,000?
A. Yes.
Q. And you're projecting $1,089,000?
A. Yes.
Q. So you're right. This is a big ticket

item. So I need to have you tell me how did you come to that $1,089,000 versus the $3,261,000. Where would I see what you've done to make the difference here?
A. It's in my Exhibit MJM-7.
Q. All right.
A. Page 1 of that exhibit is the company's current depreciation rates without the negative -- without the net salvage built in. I've stripped out, you know, the 140 percent and those numbers we were looking at in that column.
Q. You've stripped out all of that or only the one for the services?
A. All of them.
Q. You stripped out all of them?
A. Yes.
Q. Did the company show any cost for some of those, to remove some of those?
A. Yes. They have costs to remove some, but overall the cost has been positive as shown on Exhibit MGM-6.
Q. And that's because of the building being added in?
A. No. The building is separate. That's in common utility. The natural -- on the natural gas

side, for the last five years, setting aside common, setting aside electric, the actual net salvage experience for the company has been positive every year.
Q. All right. So those positive numbers mean that there's a positive -- that it is a positive cash flow, doesn't mean that its cost -- when the first one says 440,703 --
A. Mm-hmm.
Q. -- in 2001, that means that that's a positive number, there were no costs that the company incurred?
A. That is a net positive number. Net pluses and minuses.
Q. So they had some costs, they had some money that they showed from what? Income from what?
A. I don't know. Probably is some reuse involved in that. Let me see. It seems like the company is obtaining a fair amount of positive salvage on underground conductor and devices, which, you know, I don't know if they are selling them or reusing them. So that's one source. I'm sorry. I'm looking at the records.
Q. Okay. Take your time.
A. I was having a disconnect there. What the

heck is going on? There's a positive salvage on mains. I'm just looking at 2001.
Q. That means they will sell gas mains?
A. I don't know. I don't know what the source is. Power operated equipment could be reused. Bottom line, I don't know all of these things. I do know that it's been positive, net positive.
Q. All right. And so you added up those net salvages on the natural gas and it came to 1,444,452?
A. Yes.
Q. And is that what you subtracted then from -- then we still have a different number from their 2003, 3,261,000 and your 1,089,000. What's the number?
A. I stripped out the negative salvage -- all the salvage ratios from the depreciation rates themselves. And in distribution plant that resulted in a 2.37 percent composite depreciation rate rather than the company's existing depreciation rate. The next thing -- so I applied the rates without the net salvage allowances to the plant balances, which is the way it's done in the rate case, and then to that total I subtracted the average positive salvage that the company has experienced in the last five years,

including the gain on the sale of the building. If the company had regularly experienced negative net salvage, I would have added, you know, one-fifth of that amount to the annual depreciation expense.

And, again, the average net salvage is $848,010 shown at the bottom of MJM-6, page 1.

Q. Right. And then you did what with the sale of the building?

A. I included that in that average annual experience amount.

Q. Over five years?

A. Yes.

Q. To give the ratepayers a credit --

A. Yes.

Q. -- for that? And that's how you came up with the Snavely King $1,089,000?

A. Well, the Snavely King $1,089,000 is shown ultimately on Exhibit MJM-7, page 3.

Q. All right.

A. Up above it says company proposal, 2003. Those numbers show the application of the company's depreciation rates to plant balances of the sum $3,261,000 that they're proposing. And below shows the application of the depreciation rates without the net salvage built into them to the same plant

balances. That sums to $1,937,000, from which I subtracted the average annual net salvage of $848,000 to arrive at my recommended $1,089,000.

Q. Thank you. Now, the current income taxes, we haven't heard anything about that and yet I notice that that's also a substantial difference in the amount.

A. Are we --

Q. Page 2 of 4 of MGM-1.

A. Yes. Current income taxes, I've used the same procedure as the company to calculate that amount and that amount -- that calculation is shown on page 3 of 4 of Exhibit MJM-1.

Q. And your calculation shows 500 -- a charge of 529,000; is that what the negative --

A. That's a negative current income tax expense. And the reason for that has something to do with the deferred fuel lag, I think, the lag and the recovery of deferred gas expense resulting from the PGA.

Q. Help me interpret the negative number. I'm sorry. I'm having trouble with that. The negative number means that just -- is that something they will pay or they won't pay? I see a positive number of 4,322,000 in current income taxes that they are

going to pay in 2001. Does that mean they are actually going to pay 4,322,000 in 2001? I'm looking at MJM-1, page 2 of 4.

A. I don't know. My suspicion is they didn't pay that --

Q. All right.

A. -- as a result of all kinds of timing differences.

Q. But the next number means that they would have a credit of $3,067,000, is that what that negative -- is that what the parentheses mean?

A. Yes. And it has to do -- again, it has to do with the interrelationship of the PGA and deferred fuel balance.

Q. And the next number means that they would also have a credit of $1,961,000?

A. That's what -- yes.

Q. So the number that you're showing as a credit of $529,000 is actually less of a credit than what the company is showing to the ratepayers?

A. Yes, because I'm showing more income than they are so I have less of a tax credit than they do.

Q. You're showing more income than they are?

A. Net income before taxes.

COMMISSIONER REINBOLD: Mr. Hearing Examiner, if we are not going to finish off this witness tonight, let's wait until morning.

MR. HOBERG: I think perhaps we're close.

COMMISSIONER REINBOLD: Are we close?

MR. HOBERG: Well, we only have Commissioner Wefald, Commissioner Clark and perhaps not very many questions. Mr. Diller has a couple.

COMMISSIONER REINBOLD: Okay. You're the Hearing Examiner.

MR. HOBERG: I think maybe, if we can, finish it off in just a few minutes.

Q. (COMMISSIONER WEFALD CONTINUING) If I can just understand that number, then I'm done. All right?

A. The negative current tax number. Every time I come to North Dakota I get one of these.

Q. Maybe Mike Diller can explain it to me, but I better ask you. Why you're showing that it should be a smaller credit for the customers than the company does?

A. Because my net income before taxes, what I estimate for 2003, is higher than the company's. That's one reason why my recommendation is for less of an increase. I'm recommending a decrease.

Q. All right.
A. So the more net income before taxes that you estimate, the less current taxes -- no. The more current taxes you would have. And we're dealing with negative numbers here because I'm estimating more net income. I'm estimating more current taxes, which is less of a credit than the company.
COMMISSIONER WEFALD: All right. Thank you.
MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.
COMMISSIONER CLARK: Just a couple questions.

EXAMINATION

BY COMMISSIONER CLARK:

Q. The 140 ratio, maybe you mentioned this, but I'm not sure that I picked it up. Now that I understand the math better, again, how is that arrived at for, you know -- and I know you didn't have access to the information that the consulting firm that did it back in the early '90s. But typically how would that be figured and what input would go into figuring that 140?
A. Typically, the way it's done is, in the

depreciation studies that I've been involved in, there are typically tables that show annual retirements by year, then gross salvage by year, and cost of removal by year. And the net of those gross salvage and cost-of-removal numbers are related to the retirements to arrive at these ratios.
Now, there's all kind of problems with that approach to the analysis, but that's the way it's typically done, or has been typically done. I look through the Stone & Webster study and I don't see any of those kind of analysis, so I don't know -- you know, I do know that in that study it said to the extent such data, net salvage data was available. I think it's quite possible that it was an off-the-top-of-the-head estimate because the company doesn't record any net salvage for services.
Q. So your recommendation is because it's a positive number, it should just be sort of zeroed out?
A. No. I'm recommending we abandon the procedure entirely and take -- because the new thinking in the accounting profession is that if you don't have a legal obligation to incur that kind of cost on a long-life asset, you probably should expense it or perhaps, in my opinion, capitalize it

to the replacement. Most of these things -- in this we're dealing with mass property plant here. We're not dealing with power plants or nuclear plants. We're dealing with services and mains that get turned over all the time. There's constant activity. They have blanket work orders to do this kind of work. And that to me looks a heck of a lot more like an annual operating expense than something you should treat as a capital cost to inflate depreciation rates. On the other hand, you treat it as a replacement cost and capitalize it.
Q. Now, that is starting to get into the point about the AROs or asset retirement obligations and that gets into the SFAS No. 143. Okay. Let's assume that in college I was reading about the Civil War --
A. Yeah.
Q. -- as opposed to GAAP. Can you give me some examples of, you know, in a concrete way what this ARO means? I understand it is talking about incurring legal obligations. But what -- kind of lay out a couple of examples of what would be an actual obligation.
A. I think that one that pops in is the retirement to remove a nuclear plant and that's

going to cost some money. So what -- and there may be a legal requirement to remove any kind of electrical plant, although I'm not sure.
COMMISSIONER WEFALD: Or gas plant.
THE WITNESS: Maybe a gas plant, manufactured gas plant or something like that. But if there is, what this thinking says, if there's an obligation -- normally when you buy a gas -- say, you buy a manufactured gas plant and it costs $1,000, you debit gas plant, that's plant in service, and you credit a liability, long-term debt or cash or something, but you have something. So the cost of that plant is $1,000. The rationale that underlies FAS 143 is that if you have a legal obligation to then remove that plant, say you estimate it would cost you $200 to remove it and you have a legal obligation to do that, then that is part of the cost of the plant so it gets capitalized as $1,200. But you don't do that unless you have a legal obligation to incur that cost. If you don't have a legal obligation to incur that cost, and this is just replaced as normal things do, you probably would expense that cost.
COMMISSIONER CLARK: Okay. That's all I have right now. Thank you.

MR. HOBERG: Thank you, Commissioner Clark. Mr. Diller, do you have some questions?
MR. DILLER: I hesitate to ask a question. Commissioner Reinbold looks like he's ready to leave.
COMMISSIONER WEFALD: We could maybe wait until tomorrow morning.
MR. DILLER: I don't have that much. It's real general.
MR. HOBERG: Any further questions then of Mr. Majoros?
COMMISSIONER WEFALD: I don't want Mr. Diller to not ask questions.
MR. BINEK: I'm going to have a couple of short questions. I mean, they shouldn't take but a couple minutes.
MR. HOBERG: Is yours pretty short, Mr. Diller?
MR. DILLER: Yes, it is.
MR. HOBERG: Commissioner Reinbold?
COMMISSIONER REINBOLD: You're the Hearing Examiner.
MR. PEARCE: I have one question, if I may, at some point, too.
MR. HOBERG: So we have four questions left

of Mr. Majoros. He's going to be back tomorrow, isn't he? Let's recess tonight and finish in the morning.
(Recessed at 5:04 p.m., the same day.)

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

Montana-Dakota Utilities Co. Natural Gas Rate Increase Application

CASE NO. PU-399-02-183

TRANSCRIPT OF HEARING

State Capitol
Commission Hearing Room
Bismarck, North Dakota
October 8, 2002

Before Allen C. Hoberg
Hearing Officer

(The following proceedings were had and made of record, Monday, October 8, 2002, commencing at 9:00 a.m.)

MR. HOBERG: Let's go on the record. This is day two of the hearing in the matter of the application of Montana-Dakota Utilities Company for a natural gas rate increase. Yesterday we concluded -- almost concluded -- we did conclude the direct examination of Montana-Dakota Utilities and we're taking the direct testimony of the staff's case, and we have concluded Mr. King and we're almost, I think, done with Mr. Majoros.

Is there anything we should discuss preliminarily before we finish the testimony of Mr. Majoros today?

COMMISSIONER REINBOLD: I have to leave by 5:00 today.

MR. HOBERG: Hopefully, we're all able to do that. All right. Then I think --

MR. BINEK: Just one point. Yesterday Mr. Pearce or someone from MDU had indicated that one of their witnesses needed to leave early.

MR. PEARCE: That's no longer the case. I'm sorry. I forgot to mention that to you. We have no constraints anymore.

MR. HOBERG: I think when we get done with Mr. Majoros, we'll pause briefly and talk with counsel about what we're going to do in regard to rebuttal testimony, the order. I know you handed out a sheet here, and then mark your exhibits. It's a little bit different format for the exhibits for the rebuttal here, so the Court reporter -- we'll take time to mark those with the Court reporter. That will just take a couple minutes, though, I think.

All right. I believe we had concluded the Commissioners' questions of Mr. Majoros. So, Mr. Binek, did you have any additional questions of Mr. Majoros?

MR. BINEK: I do, but I think that you were at Mr. Diller.

MR. HOBERG: Was I at Mr. Diller? I'm sorry. Okay. Mr. Diller, please.

EXAMINATION

BY MR. DILLER:

Q. Good morning, Mr. Majoros.

A. Good morning.

Q. The depreciation issue is fairly huge in this case. It looks like it's $2.2 million of the difference between the company and staff position

and so I've got a few more questions on depreciation.

Maybe we could just start first by if you could answer this question. If we were -- if the Commission was to adopt your position, how many years would it take for the depreciation reserve to straighten itself out?

A. I would -- to answer that -- I can't give a precise answer to that question. But I would say if you adopt what I'm recommending here, which is to eliminate the negative net salvage from the company's depreciation rates, which would reduce those rates, and then amortize the positive net salvage that they've experienced, including the gain on the building over five years, that, combined with normal plant growth, should start to resolve that problem in about five years, I would think. Would be well on its way to resolving itself.

Q. So in your mind this wouldn't be a fix that would straighten itself out over one year's time, it would take a number of years?

A. Yes.

Q. And you're guessing maybe five years?

A. I'm guessing five years for it to make a significant dent. It will never resolve itself

entirely until, you know, all of the assets are fully depreciated and that would generally be over the average remaining life of these assets.

Q. The difference is so big between the parties I was just wondering -- I mean, if the Commission decided that it wanted to end up somewhere in between, would it matter whether the differences were resolved over five years' time or 10 years' time or 15 years?

A. No. What the Commission -- you know, the Commission could also recalculate rates with new service lives and calculate remaining life rates and then that resolution would be probably longer than five years.

Q. Can you tell me why depreciation is such a big issue here philosophically? I mean, why does the company care whether we use $1 million worth of depreciation expense or $3 million of depreciation expense? Forget about that expense is supposed to match revenues, expense is supposed to match the customers causing the cost, but philosophically, why would the company care one way or the other?

A. Probably because it represents pure cash flow to the company. The more depreciation that's charged, the greater the free cash flow flowing into

the company. Any reduction to that amount is a reduction in cash flow.

Q. Would there be any benefit if the state were to go to, let's say, retail wheeling or some kind of electric reform where it wasn't under rate-of-return regulation, would it be beneficial to have your plant assets depreciated more than is necessary at that point in time or less than is necessary?

A. Well, at that point in time, I think that if I were running the company, I'd want the correct depreciation rates.

Q. You'd want the correct ones?

A. Yes.

Q. It wouldn't be beneficial in a competitive environment --

A. No.

Q. -- to have your assets overly depreciated?

A. No, because in a competitive environment, depreciation does not drive cash flow. It's only in a regulated environment that depreciation drives cash flow because it's built in as a component into the price that's being charged to ratepayers. In a competitive environment, depreciation is an after-the-fact entry on the company's books. Prices are set by the market in a competitive environment.

Q. Okay. So in your mind it's all about cash flow?

A. In this case, yes, that is correct.

Q. Okay.

A. It's all about cash flow and the correct theory and rates.

MR. DILLER: Right. I think that's all the questions I have.

MR. HOBERG: Thank you, Mr. Diller.

Mr. Binek, did you have some more questions of Mr. Majoros?

MR. BINEK: Yes, just a few.

REDIRECT EXAMINATION

BY MR. BINEK:

Q. Mr. Majoros, should ratepayers have benefited from the gain in the building sale?

A. Yes.

Q. How should that gain have been reflected in depreciation?

A. Probably under the existing procedure should have been reflected in depreciation as a positive net salvage ratio in the structures and improvements account.

Q. Was it, to your knowledge?

A. No, it was not.

Q. Okay. What salvage value did the company apply to account 390, that's general plant structures and improvements?

A. If you turn to my Exhibit MJM-4, page 2 of 2, which is common plant, general plant, the building I think was included in account 390, structures and improvements, and you can see that that was depreciated using a negative 10 percent net salvage ratio.

Q. What are the advantages or disadvantages of extending the time period for correcting the depreciation as you have proposed?

A. What are the advantages or disadvantages?

Q. Yeah.

A. To whom?

Q. For the ratepayers.

A. Well, I would say for the ratepayers the advantages of going with my proposal is we get that reserve situation resolved quicker rather than later.

Q. Does it result in lower rates?

A. Yes.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek.

Mr. Pearce, did you have some additional questions?

MR. PEARCE: No. No, I don't.
MR. HOBERG: Thank you, Mr. Pearce. Any further questions then of Mr. Majoros at this time?
COMMISSIONER WEFALD: I have one.
MR. HOBERG: Commissioner Reinbold, please.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. Yes. Mr. Majoros, review for me again when you say small interruptible customers are being overcharged, how, when and why. You said that, didn't you?

A. No, I think Mr. King said that.

Q. Oh, okay. I'm long behind in my notes.

A. One reason they're being overcharged is probably too much depreciation is flowing into their rates.

Q. Okay. I'll take that for now. And I understand the term, but I want to hear you define the phrase "cash flow," in your mind.

A. Cash flow?

Q. Yeah.

A. As I'm using it here it means cash flowing from ratepayers into the company without any corresponding cash outflow. Arrives at the company -- if we talk about labor expense, cash

flows into the company from ratepayers, but there's an offsetting cash outflow, so there's zero cash flow impact of that being included in rates. But with depreciation, cash flows in and there's no corresponding cash flow out, so it's there, stays there for the company's use for whatever it chooses.

Q. So then it becomes a balancing act?

A. Not in my mind, no.

COMMISSIONER REINBOLD: Okay. That's all I have then.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald.

COMMISSIONER WEFALD: On -- well, I guess this relates to whether I'll have a chance to ask a question of staff after we hear the rebuttal of MDU. If I won't have a chance, then I would ask now. But if I will, then I would wait.

MR. HOBERG: Whether he's coming back on as surrebuttal?

COMMISSIONER WEFALD: Yeah.

MR. HOBERG: Mr. Binek, do you intend to call these witnesses, Mr. King and Mr. Majoros, after the rebuttal of MDU?

MR. BINEK: It's going to depend on what the rebuttal of MDU is. Ordinarily, we would not,

but if there's some new evidence that comes in, for instance, we would probably want to rebut that.

COMMISSIONER WEFALD: Should I just ask my question now?

MR. HOBERG: Well, Mr. Pearce, it sounded like yesterday you were expecting them to be called back on.

MR. PEARCE: No.

MR. HOBERG: You weren't. Oh.

MR. PEARCE: I certainly wasn't. I would be quite surprised. In fact, I hope it won't just go on forever and forever that we would have another surrebuttal on the surrebuttal.

MR. HOBERG: Perhaps ask it now then.

COMMISSIONER WEFALD: Then I'll ask my question now.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. On page 17 of Mr. Jeter's testimony he says --

COMMISSIONER REINBOLD: What page are you on?

COMMISSIONER WEFALD: Page 17 of Mr. Jeter. That's in this book here, in the rebuttal testimony.

Q. (COMMISSIONER WEFALD CONTINUING) The

paragraph starting with line 4, the question and then it goes through line 12. "Included in this discussion --

MR. HOBERG: Commissioner Wefald, excuse me. He needs a chance to find it here.

Q. (COMMISSIONER WEFALD CONTINUING) It's in the rebuttal testimony and exhibits. It says, "Included in his discussion of salvage on page 12 of his testimony at lines 1 through 2, Mr. Majoros says, it appears that the company has not recorded any net salvage at all for services; is that true?"

"No. I understand from company personnel that the company has recorded 1.4 million of net negative salvage for services during the years 1995 through 2001. Mr. Majoros took his data from a report of retirement work in progress, which because of the use of blanket work orders show services combined with mains. That is apparently the reason he concluded there was no net salvage applicable to services."

Yesterday I remember that you said that there was no net salvage applicable to services. Did you get your information from this report of retirement work in progress?

A. I got my information from the company's

response to my data request to provide all net salvage for even back prior to 1995, and it may be that they provided a blanket work order or this retirement work in progress material in response to that. But I can tell you that material clearly shows various accounts on it and the one that is strikingly missing is services. So for the company to say that it has recorded 1.4 million of negative net salvage for services, they haven't proven it to me. At this point everything I have says they didn't record any net salvage for services. And I'm responding based upon the information they provided me. Mr. Jeter makes this statement, but there's not a document to support it in his testimony or exhibits.

Q. When you requested the information from MDU, what did you ask for? What did your data request say?

A. My data request No. 21 referenced statements A through F, G through L, N through O, and those are the company statements. Question, Please provide annual North Dakota gas utility gross salvage and cost of removal by plant account beginning in 1986 through 2003.

Response, Please see Attachment A. For the

years '86 through '94, the information is available for the total company only. For the years 1995 to 2001 show both -- the years 1995 through 2001 show both total company and as allocated to North Dakota. Please see Statement O, pages 5 and 6, for salvage and removal costs for projected 2002 and 2003.

And this material I got, here is the -- I guess it's the retirement work order document that Mr. Jeter is referring to. If you want to take a look at it, you can see that it has account numbers and accounts, but one account that is missing is 381. There has not been -- I mean, 380, services. There has not been any net salvage recorded from 1995 through 2001 for services.

Q. Do you want to have that entered into the record?

A. Sure. It will be the response to data request 21. I have it here. I don't know if I have all of it. I mean, I took the pages that I relied on.

MR. HOBERG: Do you have a copy of that, Mr. Binek?

MR. BINEK: We should have a copy.

MR. HOBERG: Let's go off the record.

(Discussion off the record.)

MR. HOBERG: Let's go back on the record. We're going to mark the data request 21 as Exhibit 21 for the record. Did you have any further questions, Commissioner Wefald?

COMMISSIONER WEFALD: No.

MR. HOBERG: Thank you. Any further questions by the Commissioners of Mr. Majoros? Any further questions by any of the parties of Mr. Majoros? Thank you, Mr. Majoros.

MR. BINEK: Off the record, please.

(Exhibits 22, 23, 24, 25, 26, 27, 28, 29, and 30 were marked for identification.)

MR. HOBERG: We're ready to go back on the record. We're back from a short recess to mark exhibits, and I believe we're at the point where Montana-Dakota Utilities will call their rebuttal witnesses, starting with Mr. Jeter; is that correct?

MR. PEARCE: Yes, it is.

MR. HOBERG: Okay. Please call your next witness.

MR. PEARCE: I call John Jeter.

MR. HOBERG: Mr. Jeter, I don't think you've been sworn yet.

THE WITNESS: No.

MR. HOBERG: Were you here yesterday --

well, let me give it today.

THE WITNESS: I was here. I heard it.

MR. HOBERG: But I should give it once at the beginning of the day, just to refresh everybody's recollection, and I'm required to do so by law, anyway.

Let me tell all the witnesses again that the maximum penalty for perjury in this state is a Class C felony, punishable by a maximum five years imprisonment, a $5,000 fine, or both.

Mr. Jeter, being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce, please.

JOHN A. JETER,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Would you please state your name and business address?

A. John A. Jeter, 1304 South 185th Circle, Omaha, Nebraska.

Q. What is your occupation?
A. I'm a certified public accountant and self-employed consultant. I retired from full-time association with Arthur Andersen & Company in 1991 after over 37 years with that firm.
Q. What is the nature of the work you performed while you were there?
A. I was involved in examinations of financial statements, and to a much lesser extent in design and installing accounting systems. For many years I performed other financial and accounting consultation services for utility clients.
Q. Would you summarize your educational background and professional experience, please?
A. I'm a graduate of the University of Nebraska at Omaha, from which I obtained a Bachelor of Science degree with distinction in accounting in 1954. I was admitted to the Arthur Andersen & Company partnership in 1967. I'm a member of the American Institute of Certified Public Accountants and the Nebraska Society of Certified Public Accountants. In 1994, I was elected to the Board of Directors of Tucson Electric Power Company and became a director of its parent company, UniSource Energy Corporation, when it was formed. I retired

from the UniSource board and its subsidiary boards in May 2001.

In 1991 I began consulting on my own with utilities regarding accounting and regulatory matters. As is true in this case, I have also consulted in association with Zinder Companies, Inc., a firm that provides economic and financial consultation to regulated utilities.

Q. What experience have you personally had in the utility field?
A. I have participated in or been responsible for regular audits of financial statements, registration statements filed with the Securities and Exchange Commission, the SEC, for the sale of securities, installations of property records and information systems and a variety of other special accounting services for regulated industry clients. For many years before I retired from Arthur Andersen I had regional responsibilities for its regulated industries practice, and was a member of the partnership team that established policies with respect to issues facing clients in rate-regulated industries.

I often taught at both training sessions for Andersen personnel and in training sessions

Andersen offered for its clients and others. This training ordinarily involved accounting issues, tax issues, and various regulatory matters. In 1992, I prepared a paper and presented it twice in a tutorial sponsored by the Institute of Electrical and Electronics Engineers, Inc. Power Engineering Society. The title of my portion of the tutorial was, quote, Accounting for Depreciation, Return, and Income Taxes, unquote.
Q. Have you previously testified before any regulatory agencies?
A. Yes. I've testified before the Federal Energy Regulatory Commission, the FERC, and its predecessor, the Federal Power Commission, the National Energy Board in Canada, the Interstate Commerce Commission, and regulatory agencies in North Dakota and a number of other states, and the province of Alberta, Canada. My testimony has addressed depreciation, accounting for income taxes, post retirement benefits other than pensions, working capital, and various other topics related to accounting and ratemaking issues. I have attached Appendix A, which is a his of my testimony in regulatory proceedings since the beginning of 1996.
Q. What is the purpose of your rebuttal

testimony in this proceeding?
A. I've been asked by Montana-Dakota Utilities, paren, quote, Montana-Dakota, quote, or, quote, the Company, unquote, to respond to the direct testimony of Michael J. Majoros, Jr., on behalf of the staff of the North Dakota Public Service Commission regarding depreciation rates.
Q. I believe you are sponsoring Exhibits 22, your testimony, with JAJ-2 attached, and also Exhibits 29 and 30; is that right? Exhibit 29 we just marked.
MR. PEARCE: That's actually a page from Mr. Jeter's testimony. And Exhibit 30 is a summary of negative salvage from Montana-Dakota Utilities.
MR. HOBERG: Exhibit 29 is a page from his testimony?
MR. PEARCE: I believe that's what it is.
THE WITNESS: It's a new schedule that I prepared.
MR. PEARCE: It's a schedule. I have my little yellow thing on the wrong sheet. That didn't make too much sense, did it?
MR. HOBERG: So are you offering --
MR. PEARCE: I'm not offering yet. I'm just mentioning those are his exhibits; 22, 29 and

30.

Q. (MR. PEARCE CONTINUING) Will you please summarize your conclusions?

A. Yes. The company is using the depreciation rates included in Case No. PU-399-94-297 based on a depreciation study completed in 1992. Currently, Montana-Dakota has retained AUS Consulting to complete another depreciation study by December 31, 2002. There should be no change in depreciation rates until that study has been completed and the appropriate review has taken place as Mr. Majoros did not prepare a depreciation study, has not presented -- has presented no evidence that the depreciation rates should be changed at this time. A proper depreciation study will involve reviewing additions, retirements, transfers, balances, salvage, removal costs, and accumulated depreciation for the entire history of each account in gas plant and common plant for Montana-Dakota's gas distribution, none of which Mr. Majoros did.

Mr. Majoros' reference to cash flow as a basis of setting depreciation rates is completely incorrect and his use of the rough turnover estimation procedures is not reliable and is not used to measure depreciation rates when study data

is available, as it is in this case. His comments regarding net salvage are largely his unsupported opinions and are not based on any analysis of Montana-Dakota facilities, experience, or operations.

Q. Would you please describe the facilities being depreciated by the company?

A. Montana-Dakota's facilities include gas distribution properties in North Dakota that are used to serve approximately 83,500 customers in 76 communities. In addition, there are common facilities that are used in connection with the electrical gas operations in North Dakota and other states, the costs of which are directly assigned or allocated to the North Dakota gas operations.

Q. On pages 5 through 9 of his testimony, Mr. Majoros discusses a relationship between cash flow and depreciation. Is this a normal type of depreciation analysis?

A. No. Mr. Majoros states that depreciation is not intended to finance additions on page 6, lines 3 through 4, but then compares Montana-Dakota's companywide depreciation expense with the plant additions that were made during the years 1996 through 2001. It is well established that

depreciation is not intended to finance plant additions and the relationship between the two is largely meaningless for determining the appropriate time period during which the company's plant should be depreciated.

In spite of this, Mr. Majoros concluded at lines 25 to 26 at page 6 of his testimony that the company, quote, is financing all of its plant additions from depreciation funds it collects from ratepayers and still has a substantial amount of additional cash for other matters, end quote. There is no way he can support that conclusion, because he is assuming incorrectly that there are no other requirements for the cash flow.

Moreover, since depreciation is meant to recover the existing investment, it is irrelevant whether investors reinvest the recovered funds or, instead, find other uses for the funds. The appropriate depreciation rate is dictated by the need to recover the invested capital during the life of the facilities. By ignoring that fundamental purpose of depreciation, Mr. Majoros is effectively proposing that the depreciation rate should vary from time to time depending on the amount of cash the company is investing on projects deemed by

Mr. Majoros to be beneficial to ratepayers. Presumably, in years when the company has, quote, additional cash for other matters, unquote, Mr. Majoros would reduce the depreciation rate. Conversely, in years when the company needs to undertake major investments in plant, Mr. Majoros presumably would propose major increases in depreciation rates so that the company will have sufficient cash flow to fund all of its investments without borrowing, retaining earnings, or issuing common stock.

It is doubtful that Mr. Majoros really means to revolutionize the concept of depreciation so that customers' rates can be increased dramatically to provide financing for new investments. Nevertheless, that is the logical corollary to the new, quote, cash-flow-needs, unquote, standard for setting depreciation rates that Mr. Majoros is advocating.

Q. Is Mr. Majoros' assertion concerning Montana-Dakota's source and uses of funds factually accurate?

A. No. In addition to the fact that the comparison he made is meaningless, the amounts used are not comparable. The depreciation -- and I'm now

referring to his page 6. The depreciation in column 2 includes depreciation of common plant, but the amounts for, quote, construction/acquisition (sic) in column 3 do not include those for common plant.

Now, I'd like to insert here the fact that yesterday Mr. Majoros put forth Exhibit 20, and included in that exhibit is a schedule which is entitled page 6 table expanded. That's the top page of Exhibit 20. What he did there was to add the common plant construction in column 5, which is why it exceeds the amounts in column 3, and then show the corrected incremental cash flow. He could easily have left out columns 3 and 4 because they are obviously -- well, 3 is correct, but column 4 he could have left out because it's no longer correct and I think he would agree with that.

But I wanted to point out that he has now corrected that. During this 1996 to 2001 period there were 28,000 -- $28,064,555 of additions to common plant. This changes the incremental cash flow in his column 4 from $28,473,000 to $408,000. Now, with his expanded schedule, he comes to $409,000. So we differ again by rounding differently on that number by 1,000. The last year in the column and in his original table in his

testimony was shown as 2002 and should have been 2001, and he carried that into his expanded table. Mr. Majoros also -- excuse me. I've come to the next question.

Q. Mr. Majoros also made an analysis using just a North Dakota distribution and general plant additions and depreciation expense amounts in his Exhibit MJM-3. Is that any different?

A. No. It's also meaningless for similar reasons. Once again, his conclusion is completely incorrect. After observing that the depreciation expense for the years '86 through 2001 exceeded the plant additions by 4.5 million he says, paren, on lines 8 and 9 on page 7, close paren, quote, It seems that ratepayers rather than investors have been financing the company's North Dakota plant through excessive depreciation, end quote. Interestingly, he asserts that there is, quote, excessive depreciation, end quote, and has at this point in his testimony mentioned no basis for that other than the comparison of depreciation cash flows and plant additions, which even he agrees are not the basis for setting depreciation rates.

I'd like to insert here also based on his Exhibit 20. Well, let me first explain. The next

paragraph of my testimony I was planning to strike because it was incorrect. However, in Exhibit 20 he revised the Exhibit MJM-3 and in revising it, it's now incorrect. I said earlier that it was when it wasn't and now he's revised it and now it is, in fact, incorrect. And that's the third page in Exhibit 20. He added depreciation of common plant to the depreciation of distribution plant that was originally in his exhibit and that shows in column 2, increased amount there. But he did not add the common plant additions in column 3. Had he added them, I think the schedule would not show what he intended it to show.

For instance, in the first year, 1986, the additions, including common plant, are $2,699,841, compared to the 1,945,514 of depreciation expense. And, therefore, there would have been a negative number in the fourth column of 754,327. I didn't go through all of these to make that correction, but the only other one I did was in '89 and it has the same type of effect only more so.

COMMISSIONER WEFALD: Can you just repeat for me again which document you were looking at?

THE WITNESS: All right. His Exhibit 20 that was entered yesterday, and it's the third page

of that, ma'am, if you just turn back into it. It's several different things, and the third page is the one I was referring to.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: Yes. Now, that is supposedly the same thing as his Exhibit MJM-3, which was attached to his original testimony. And what he has done, if you look at the two, you can see that he has added amounts in column 2 each year so that the total depreciation expense instead of being $33,405,083 as it was in his original exhibit is now $37 million.

MR. HOBERG: Mr. Jeter, are you still wanting to strike that 15 through 21?

THE WITNESS: Yes. I would like to strike it, because I was referring to his original exhibit which was not inconsistent.

MR. HOBERG: Lines 15 through 21 on page 7 should be stricken and replaced with what you just said?

THE WITNESS: With what I said, yes.

COMMISSIONER REINBOLD: What are the lines?

MR. HOBERG: 15 through 21 of page 7 of his rebuttal.

THE WITNESS: It does not change anything.

I still think the exhibit is meaningless, but I had called attention to something I thought was wrong and I was wrong. It is incorrect in his new version attached to part of Exhibit 20.

MR. HOBERG: Thank you. Please continue.

THE WITNESS: It is incorrect in his new version attached to -- as part of Exhibit 20.

Q. (MR. PEARCE CONTINUING) On page 7, at lines 12 to 13 of his testimony, Mr. Majoros states, An excessive depreciation rate is one that produces depreciation and expense more than necessary to return a company's capital investment in an asset over the life of the asset.

Do you agree with the statement?

A. No, because it's incomplete. The Federal Energy Regulatory Commission in its Uniform System of Accounts for natural gas companies, paren, also used by this Commission for the gas companies subject to its jurisdiction, close paren, defines depreciation as:

> The loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which

> are known to be in current operations and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the arts, changes in demand, and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.
>
> The term "service value" is defined as the difference between original cost and net salvage value of gas plant. Since service value includes net salvage in addition to capital investment, Mr. Majoros omitted an important aspect of the recovery of cost that is necessary through depreciation provisions.
>
> I'd like to also comment here about some of the things that were said yesterday. The expense provision for depreciation includes cost of removal or salvage net and that means that they would either be higher or lower depending on the estimates of whether there's net cost of removal or negative salvage or salvage itself. The reserve is there for

the retirement of the asset and for the cost of removal or salvage as often happens. His comparison is misleading because he's leaving out those aspects of reserve for depreciation in his comparison.

Q. How would the omission of net salvage affect his determination of excessive depreciation?

A. Well, his comparisons are not only baseless, but they're also incorrect in that the entire cost is not included in his thinking. If the net salvage is negative and is estimated at 30 percent of the asset cost, he would be asserting that since the depreciation expense exceeds current additions, it is excessive. That is a wrong comparison to start with, but, in addition, he would be leaving out the fact that the expense would have to be 130 percent of the amount necessary to recover the investment in order to provide for the negative salvage or cost of removal in excess of salvage.

Q. On page 7, line 16, through page 9, line 2, Mr. Majoros quotes a U.S. Supreme Court decision in 1934 as a basis for his contention that excessive depreciation results in the extraction of capital contributions from ratepayers.

Would you please comment on that?

A. Yes. Mr. Majoros seems to have missed the

point of the Court's ruling. He refers to a cite of this decision in the NARUC Depreciation Manual as proof that it is still relevant law. The section in which this term is cited is The Brief History of Utility Regulation. Now, as an aside to that, that's a nine-page chapter. It's the first chapter of this book put out by the NARUC. The following chapter is entitled, quote, Current Concepts of Depreciation, end quote. So the chapter that he's referring to is actually a history of what has happened. Obviously, depreciation practices were still in the development stage in 1934.

Now, I'll go back to the text here. The NARUC text point out the fact that this decision overruled a 1930 decision for depreciation on fair value. That means a value that reflects changes because of inflation, typically, over time. In other words, at that time they were depreciating plant using reproduction cost, new. In other words, they were taking account of inflation over time and then depreciating that inflated amount rather than the original cost of the plant.

Now, since some of my comments about things I've read are not necessarily believed by others, I'd like to read into the record the information

that I was just talking about. And this is from page 3 of this NARUC Depreciation Manual. And it's the third full paragraph.

In 1930 the opinion of the Court had changed and reflected the belief that depreciation expense should be based upon present value rather than original cost. United Railways and Electric Company of Baltimore versus West, 280 U.S. 234, 1930. That opinion appears to have been overruled in the 1934 decision, Lindheimer versus Illinois Bell Telephone Company, 292 U.S. 151, 1934, wherein the Court stated, The method is designed to spread evenly over the service life of the property the loss which is realized when a property is ultimately retired from service. According to the principle of this accounting practice, the loss is computed upon the actual cost of property as entered upon the books, less the expected salvage and the amount charged each year is one year's pro rata share of the total amount.

So this issue had to do with whether we depreciate fair value of the property determined using various indices to estimate the value of an existing property that had been in existence for some time and then depreciating that value, or if we

should use original cost. I frankly had not heard of this case until this testimony was done. And the case you hear of is discussed in the rest of my written testimony. So I'll begin there.

Subsequent to the Hope Natural Gas Company case decided by the Supreme Court in 1944, most regulatory commissions stopped using the value method for measuring the rate base investment and switched instead to the original cost method of measuring rate base. To that extent, I believe the 1934 decision cited by Mr. Majoros is consistent with current regulatory practice, which generally uses original cost rate base for ratemaking. I believe the references in the decision to excessive recovery of depreciation refer to the use of value rather than cost in setting rates. That is certainly not an issue in this case since neither the rate base nor the depreciation amount is derived from an estimate of the current value or replacement cost of the plant.

Q. On page 9, lines 3 through 24, Mr. Majoros shows the relationship of the accumulated depreciation reserve to the plant in service and concludes that the reserves are extraordinarily high, to use his term, and that they suggest that

higher depreciation rates have been excessive.

Do you agree with this conclusion?

A. No. Without information about the average age of the plant, prior retirements, et cetera, it is not possible to tell at what level the accumulated depreciation provisions the reserve should be. Once more, Mr. Majoros has expressed his opinion without benefit of any evidence to support it.

Now, I'd like to comment here again that in his discussions yesterday he mentioned the 70 percent ratio of one of the plant items depreciation reserves to the plant cost itself. And I think we need to understand what's in those depreciation reserves in order to understand those ratios. They're not used to separate. This book says over and over that that shouldn't be done. And there are very few situations in which regulatory bodies actually look at the reserve for depreciation and say that reserve is too much or too little and we're going to correct that right away. It's done in the telephone industry to some extent, but other than that, it's practically not done at all.

The reserve has the provisions that have been charged to expense for cost recovery and for

net salvage, whether it's positive or negative, in it. Credits for salvage increase the reserve. Plant cost retired is in the reserve as a negative amount. In other words, we depreciate over the years with the idea that when the plant is retired, that depreciation reserve will equal the amount of the cost of the plant and the two will offset. It also has charges for the cost of removal because when plant is retired and must be removed, then those costs are charged to the depreciation reserve also because they have been provided for in the provision for depreciation and that goes into that reserve.

Deciding whether reserve is too high or too low is difficult. Mr. Majoros compared the reserve for all distribution facilities which is impossible to understand on its face because it includes a lot of different kind of properties, a lot of different existing ages of those properties, and a lot of different lives of those properties. You need analysis, but usually that's not done in modern depreciation practices other than as a sort of test of what's been done in more detail using curve fitting techniques that are typically used in determining depreciation rates.

Q. Are there others aspects of the level of the depreciation reserves that should be considered?

A. Well, yes. The amount in the reserve includes amounts that are set aside for the net negative salvage, as well as the amounts needed to recover original investment in the plant. Obviously, that makes the percentage relationship of the reserve to the plant amounts look larger than it would if only the investment recovery portion of the reserve were compared. More importantly, the larger the reserve balance is, the lower the rate base is and the lower revenue requirements for return and income taxes are. In some cases the level of reserve can also affect the levels of property taxes paid, and reduce them if the reserve is higher.

Q. Could you quantify the effects of the lower rate base?

A. Yes, I can do that roughly, and I want to emphasize the word "roughly." The direct effect of the lower rate base caused by larger depreciation reserve balance is to lower the revenue requirement. If it is assumed that depreciation has been less -- had been less by the amount of Mr. Majoros' proposed annual adjustment of depreciation since rates were set to be effective in late 1994, we would have

eight years, '95 through 2002, of Mr. Majoros' $2.172 million proposed depreciation expense reduction accumulated in the reserve for depreciation by the end of 2002. That would have reduced the reserve by $17,376,000 and increased the rate base by the same amount.

The effect of an increase in rate base of $17,376,000 would be to increase the revenue requirement. I've computed those amounts using Montana-Dakota's proposed 11.044 percent rate of return shown on Dr. Gaske's testimony and the 39.61 percent combined federal and state income tax rate supplied to me by the company.

Q. And what are the effects on revenue requirements using those assumptions that you mentioned?

A. The revenue requirement avoided because of the 17,376,000 is in the depreciation because that's in the reserve is about 3.2 million annually, which exceeds the 2.2 million annual depreciation adjustment proposed by Mr. Majoros. This means that there would be a greater reduction of revenue requirement -- I said would. There will be a greater reduction of the revenue requirement every year from 2002 on by having the 17,376,000 in the

reserve, than Mr. Majoros' proposed reduction in annual depreciation expense. In addition, the revenue requirement reduction does not reduce the amount of investment being recovered by Montana-Dakota as Mr. Majoros' proposed depreciation expense reduction would. The higher depreciation reserve balances, resulting in a lower rate base, has benefited Montana-Dakota's customers and continues to be a benefit in terms of reducing the revenue requirement.

Q. On page 10, lines 2 and 3, Mr. Majoros states, according to the company, no specific studies have been prepared regarding the adequacy of the depreciation reserve or calculation of any theoretical depreciation reserves.

Is that true and, if so, can you explain why it is true?

A. I understand it is true, and it's certainly appropriate. Theoretical depreciation reserves are discussed in the NARUC text on depreciation, this document, to which Mr. Majoros referred in his testimony. On page 24 the author states, quote, If, for example, depreciation rates have been prescribed by regulatory authorities for an appreciable period in the past, it would be inconsistent to deduct in

establishing a rate base a larger or smaller amount than book depreciation reserve accumulated under the prescribed rates, end quote.

The reason that the company has not done studies of the adequacy of the depreciation reserves or determined theoretical depreciation reserves is that it's inappropriate. Adjustments of depreciation are nearly always done on a prospective basis based on the determination of changes in average service lives or determinations of average remaining service lives, more often remaining service lives.

Q. On page 10 of his testimony Mr. Majoros expresses his opinion that the 1991 depreciation study by Stone & Webster included an extremely high cost of removal factor for account 380, services. Do you agree?

A. No. The 1991 depreciation study of Stone & Webster included a review of account 380 additions from 1936 through 1991 and related salvage data to the extent that it was available. I'd like to insert here some discussion, because I did not talk about the level of net cost to remove or net negative salvage that is in this case and I think that it is more understandable if you start to think

about what's involved than it is if you just look at those rates and say they're too high.

For instance, in salvage in the services area, the service again is the line from the main in the street to the home. They're typically a small-diameter pipe. The installation -- and I think there was an example of $1,000 installation yesterday, and I'd like you to think about what happens when that is installed and then a period of time of 35 years goes by and then it's taken out. For whatever the reason, maybe it's replaced, maybe it's taken out because the home is no longer occupied, but for whatever the reason. It seems to me that it probably would cost about the same amount in terms of labor, time, and equipment, and so forth to take that line out as it did to put it in in the first place. However, in 35 years the cost of doing that is going to have increased. I looked at the Consumer Price Index, and in 1967 the Index was 32.9, in January. In January of 2002 the index was at 177.1. So if the cost of doing these activities has gone up by the inflation amount shown by the Consumer Price Index, the cost would be over five times as much.

So when an estimate of net cost of removal

is 140 percent of the original cost of the facility, that may be pretty close to what's involved, but it may also be short. It may actually cost more than that. So I was accused of not having thought about this or reacted to those salvage amounts. I didn't look at the study in any detail at all, but I'm certainly more willing to accept what people did in an extremely detailed study than to just say offhand those are wrong. And so I think that the amounts that are there are reasonable, probably. Now, I can't swear to that because I haven't done the work that's necessary, but I would certainly wait until somebody does the work in the current study to see if those amounts are reasonable.

And I should mention the inflation during that 35-year period that I talked about was greater than normal. It amounted to 4.9 percent a year because of very high years in the '70s and '80s that we had some very high inflation, but even at 3 percent a year in 35 years, prices will go up 2.8 times so it's still something that has to be dealt with when you're dealing with longer life properties.

I'll continue with the rest of that answer. I would rather rely on that study than Mr. Majoros'

reaction, which seems mainly to be based on the effects of the salvage estimate rather than the basis for it.

Q. On the same page 10 Mr. Majoros concludes that the 36-year life for account 376, mains, and the 34-year life for account 380, services, may be excessive based on his experience in investigating other gas depreciation rates.

Will you please comment?

A. Yes. Again, I would rely on Stone & Webster's 1991 depreciation study. Mr. Majoros' opinion may be based on his experience, but his opinion was formed without any specific determination of the proper life or any specific basis for the life he would have led. The Stone & Webster's study used data from 1936 through 1991 and curve fitting techniques that resulted in the use of the R3 Iowa Curve to determine the 34-year life for the account 380, services. The study used data from 1944 to 1991 for account 376, mains, in the same manner to determine an R5 curve fit and a 36-year life.

The approach used by Stone & Webster for these two accounts is widely used by depreciation experts, including the FERC staff, to determine the

appropriate lives to use to depreciate gas utility plant.

Q. On page 11, lines 1 through 15, Mr. Majoros discusses the geometric mean turnover studies he used to test service lives.

Will you please comment on that?

A. Yes. First, the use of the word "studies" should not be interpreted to mean he did a depreciation study. What he did is a very limited review of certain data, with some unexplained calculations. He said in the testimony that he used the last five years of additions and retirements. However, his Exhibit MJM-5 shows additions and retirement for the period 1985 through 2001. In addition, his exhibit labels certain of the data as a three-year band and it appears not to be for any three-year period. His schedules on Exhibit MJM-5, pages 1 of 4 and 3 of 4, show average plant balances in column b for each year based on the balances at the beginning of the current year and the beginning of the prior year, which means the average balances are all shown for the wrong year. They are all actually averages of the year previous to the one shown.

The average plant balance additions and

retirement shown under the three-year band caption are in each instance the sum of the current year and the previous year amounts from columns b, c, and d. Thus, they are not for three years and they use those incorrect average balances from column b that I discussed. Using the data for this 17-year period Mr. Majoros computed a life estimate of 108.07 years for account 376, mains, and a life of 68.53 years for account 380, services. He does not explain how the data for this 17-year period is reliable, nor how the method he used works to determine the lives.

Now, I'd like to insert here a comment based on the discussions yesterday in the hearing. Exhibit 20 has comparisons of company and industry averages and to put the lives that Mr. Majoros determined in that methodology in context, I'd like you to look at the second piece of paper in Exhibit 20, which is the statistics for lives that he presented. And in that example taking mains, which is account 376, the company life is shown as 36 years. The lives that he got averages from statistics for gas plant, and I assume a rather wide group in the United States are around the 50- to 55-year lives. The minimum life was 10 and the maximum life was 80.

As I'll discuss later, Mr. Majoros has adjusted his MJM-5, and he now finds that the life should be 116 years. One hundred sixteen years exceeds the maximum life of 80 years shown on his schedule by quite a lot and I think is totally meaningless in the context of depreciation rates for this company.

Similarly, on the services the company is using a 34-year life. The range for others is from 10.2 to 40 years. And the maximum life shown was 63 years. His revised determination is 74 years. Again, substantially higher than any other company has or is using. That's in the survey that he produces numbers from.

I'm going back to the text now. In the case of account 376, mains, the 1.167 million of retirement for all of the years from 1985 through 2001 are only 6.2 percent of the balance at the beginning of 1985, and a smaller percentage of the 1985 balance plus subsequent additions. In the NARUC depreciation text mentioned by Mr. Majoros, the turnover methods are discussed in Chapter 8. The geometric mean turnover method he used is described on page 81 as follows, quote, The Asymptotic method and its simplified form, the

geometric mean method, are based on ratios of annual additions and retirements. The latter method more readily indicates trends, but is also prone to producing results with considerable variability. The simplicity of the turnover method and the ease with which they may be applied explain their popularity. Their use is restricted by the assumptions of uniformity and their failure to provide an indication of retirement dispersion. These problems led to their replacement by the Simulated Plant Record model.

Further, under the caption "limitations" on page 92 of the same text, NARUC text, the following summary statements about turnover methods are made. Quote, All of the methods assumed uniformity of the growth ratio and dispersion of retirement for each vintage. A more reliable estimate may be made if the property has experienced at least one life cycle, roughly twice the average life, since, under the consistency assumptions above, the property will be at stability. Since utility property typically does not meet the above consistency assumptions, the method may produce considerable variations in life indications. This is especially true for the geometric mean method.

Now, if you think about applying that, this document says that you need roughly twice the average life of data. Twice of average life that he determined would be 232 years, and I don't think we have any data back to the 1700s.

The 1968 addition of the NARUC text stated on page 138 -- now this is a long time ago, this document. Turnover methods are currently used very little because improved methods have been developed for determining service lives from recorded data. I do not believe Mr. Majoros' conclusions based on his very rough analysis of this data should be given any weight in determining the proper lives to use for Montana-Dakota distribution facilities.

Q. Turning for a moment back to page 14, line 21, you said chapter 8. Did you mean chapter 7?

A. Excuse me. Chapter 7. I misspoke. I also would like to insert here that during Mr. Majoros' summary yesterday he mentioned that the Stone & Webster study had talked about a turnover method and he quoted a paragraph from page 4 of their report. I'd like to quote it again and comment on it, if I may.

I believe the quote was -- and this is from page 4 of that document. The turnover testing is a

procedure in which the adjusted turnover period, the number of years it takes an investment in plant to be retired, is determined by aggregating additions from the year 1991 backward until the total is equal to the plant balance in that year and then adjusting for the rate of growth in the account.

Now, keep in mind, they're talking there about dealing with additions back through the years from the time that they did their study until they could account for all of the balance that was there when they looked. I just mentioned he looked at only 6.2 percent of the retirements in his study and that the additions would have been something less than 50 percent. So he did not do what Stone & Webster said they did. They were both called turnover methods, but his method is a much simpler and less reliable method.

Q. On pages 11 -- sorry. On page 11, line 18, through page 12, line 11 of his testimony, Mr. Majoros discusses net salvage ratios and refers to his Exhibit MJM-6. He concludes that the company's net salvage recovery is vastly overstated.

Do you agree?

A. No. I believe the 1991 depreciation study prepared by Stone & Webster is a much more reliable

source of information regarding net salvage than a cursory look at the net salvage for all accounts over a five-year period. By the way, Mr. Majoros talked about that method being used in, I believe, Pennsylvania and Kentucky. Which said another way is that it's not used in the other 48 states, nor by the FERC, nor by the FCC, nor by anybody else that I'm aware of. It is a method that is bound to charge the wrong customers for these items. The new financial accounting standard is clearly aimed at having the cost of removal spread over the life of the facility so that the customers that have the benefit of that facility are paying for it. Spreading net cost of removal or salvage from a previous five-year period doesn't accomplish that at all and it is bound to be incorrect.

There's been several mentions of a gain on the sale of a building. And I may cover that later in the printed documents. I will. But it's been mischaracterized as a gain several times, including this morning again in cross. There was no gain on the sale of the building. Salvage is the entire amount realized from the sale of the property when it's retired, not the gain on the sale. This building was sold for book value. The salvage went

to the depreciation reserve and there it reduces rates for customers because it's a reduction of the rate base.

And in addition to that, it equaled the amount that they needed because they sold it for book value. So this using a five-year average and including $4.6 or 8 million in the future five years based on that, is totally wrong. First of all, even if that should be done that way, and it shouldn't, but if it should be done, there's not going to be another sale of a building likely in every five-year period in the future, nor one-fifth of that amount realized in any of the five years. It's just absolutely wrong.

I want to make sure everybody understands there was not a gain on the sale. There was nothing that the customers are never going to realize. This building was sold for its net cost. In other words, its original cost less the depreciation that had been accumulated on it from the time that it was placed in service.

And I'm going to continue reading now from my text. I also believe that the cost of removal will tend to be paid near the end of the average life of plant facilities and cannot be estimated

accurately using broad averages of short periods of data as was done by Mr. Majoros. Mr. Majoros used data without so much as questioning. The amounts by year for natural gas vary from $79,685 to $440,703. In addition, the amounts for common utility facilities varied from 12,377 in 1997 to $4,889,037 in 2001.

As I mentioned, I understand that the large amount in 2001 involved the sale of an office building for 4.6 million. The electric amounts include an insurance recovery of about 1.8 million and much of the other salvage during the period is for vehicles and work equipment. These are relatively short-life assets. The salvage very often is trade-in value when work equipment is traded in on new work equipment.

I will discuss the recommendation -- excuse me. In summary, Mr. Majoros has very little basis for his comment and for the effect of net negative salvage he used in his final recommendation. I will discuss that recommendation later in the testimony.

I do not understand Mr. Majoros' comments about the recovery being overstated. I assume the accounts being recovered are being recorded by the company in the records. Perhaps he means that the

amounts being recovered are excessive, and I have commented above about his complete lack of evidence for that claim. He also states on page 12 of his testimony that the company's, quote, ratepayers are being penalized, end quote. The ratepayers will receive full benefit of the amounts recorded by the reduction in rate base as I described above.

MR. HOBERG: Perhaps this would be a good time to take a 10-minute recess. I think we're going to continue for a while. Let's take a 10-minute recess at this point.

(Recess was taken.)

(Exhibit 21 was marked for identification.)

MR. HOBERG: We're back from recess and, we'll continue the examination of Mr. Jeter.

Mr. Pearce, please.

MR. BINEK: Your Honor, I just wanted to mention that I passed out copies of Exhibit 21 during the break.

MR. HOBERG: Thank you, Mr. Binek. This is the big one. It's the data request 21 and the response, which is marked as Exhibit 21. Thank you.

COMMISSIONER REINBOLD: 21?

MR. HOBERG: 21, yes, Exhibit 21.

Mr. Pearce.

Q. (MR. PEARCE CONTINUING) Mr. Jeter, included in Mr. Majoros's testimony in a discussion of salvage he says, it appears that the company has not recorded any net salvage at all for services. Is that true?

A. No. I understand from company personnel that the company has recorded 1.4 million of net negative salvage for services during the years 1995 through 2001. Mr. Majoros took his data from a report of retirement work in progress, RWIP, which because of the use of blanket work orders shows services combined with mains. That is apparently the reason he concluded that there was no net salvage applicable to services.

Now, earlier this morning this was discussed again. And at the time that I wrote the testimony, I had just been informed of that. Subsequently, I asked for some data from the company to explain that. And I should mention I think this was an unfortunate thing. The response to the original data request was misleading. I think there was reason to believe looking at it that there were no salvage amounts for services because they didn't show there. And they were combined because of the kind of blanket work order treatment the company

gives them.

But, in any event, there were actual net cost of removal for services during the period involved. And I have with Exhibit 30 summarized several pages of data that I was given by the company. Each of those pages is headed up services-removal cost. And I have taken the total amount for the year from each of those pages and summarized it in the column called annual on the top page. And you can see from that, that this totals up to $1,387,946.12 or 1.4 million. And the documents that I got did not have monthly detail for all of the months of the year, but on that top schedule I summarized some of those just to get a feel for it. The trouble is, those monthly amounts are not necessarily representative in North Dakota because they're for January and I doubt that there's a lot of construction going on in this part of the world in January, no more than necessary probably. But in any case there were, in fact, a million-four of cost of removal.

Now, I said in my testimony net negative salvage. Looking at these schedules, there could have been some positive salvage that's not accounted for here. I doubt it because typically service

lines don't generate any material that can be sold or used again. But that could be that there is some actual salvage values that are not even in this more detailed review.

Q. Mr. Majoros then guesses the company may be recording cost of removal in connection with services replaced as service transfer expense. Is that what the company is doing?

A. No. As I mentioned above, the company has informed me that the net salvage has been recorded in the accumulated depreciation accounts, the reserve.

Q. Then to the extent you relied on his statements about account 380, services, his conclusion is unsupported; is that right?

A. Yes.

Q. On page 12, lines 13 through 21, Mr. Majoros discusses FAS No. 143 and the changes he believes will be required for fiscal years beginning after June 15th of 2002. Would you please summarize the effects of FAS 143?

A. Yes. I prepared Exhibit JAJ-2, a simple example of the accounting changes involved. On the exhibit -- and it probably would help if we look at that together -- I have assumed a $10,000 plant is

completed on January 1, 2001 and there is an estimate of $500 of cost of removal and no salvage at the time of its estimated retirement on December 31, 2010.

COMMISSIONER WEFALD: I need some help with where this exhibit is found.

THE WITNESS: It's attached to my testimony.

MR. HOBERG: His rebuttal testimony, the very last page.

THE WITNESS: The very last page. In that section we --

COMMISSIONER WEFALD: TAA-5, is that the one we are looking at?

MR. PEARCE: JAJ-2. You must be in the wrong --

COMMISSIONER WEFALD: JAJ-2?

THE WITNESS: Yes.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: The owner of the plant applies a credit adjusted risk-free interest rate to discount the cost of the removal obligation to its present value of $254.17. Now, I'm assuming those things, and the assumptions are basically all shown at the top of the exhibit.

COMMISSIONER WEFALD: Where is this $254 figure?

THE WITNESS: It's at the right-hand side of the top little section there, right below the 7 percent, and it was derived using the 7 percent. That's the present value of $500 10 years out using a 7 percent discount rate. In other words, if you invested $250.17 at 7 percent, 10 years later you would have the $500.

Under existing accounting, as shown at the top table on the exhibit, the depreciation expense would reflect the $500 of cost of removal as an additional provision for depreciation of $50 per year and the total depreciation expense credited to the reserve for depreciation would provide for the retirement of the asset and the cost of removal. The plant and reserve accounts would be zero at the end of the life.

Now, you can see there I've labeled it expense. That's the provision for depreciation that goes to expense and is credited to the depreciation reserve which increases the reserve. At the end of the life -- and this assumes perfect estimation -- there would be $1,000 of plant taken out of the plant records and charged against the reserve, and

there would be payments of $500 to remove that facility. And the balance in the depreciation reserve would therefore become zero and the balance in the plant account would also be zero. That's quite a lot simpler than what I'm going to tell you about next.

Because under SFAS 143 the $254.17 present value of the estimated cost of removal would be recorded on January 1, 2001 as a liability and as an addition to plant. Now, you can see that in the first line of that lower table where plant starts out at $10,254.17. Depreciation of the adjusted plant would be $1,025.42 per year instead of the $1,050 recorded under existing accounting rules. Now, you can see that's a lesser amount, and the reason it's smaller is that we're dealing with a present value of that future payment that has to be made and that's the amount that would be depreciated and recovered through depreciation. In the depreciation -- well, let me read on.

The present value of the liability that would be set up offsetting that addition to plant must be increased each year as the time for settlement approaches. The accretion recorded to do that is the discount rate times the beginning of the

year balance each year. On the exhibit that shows up as $17.79 in 2001 and increases each year until 2010 when it is $32.71. Once again, the plant and reserve accounts, as well as the liability accounts all stand at zero at the end of 2010.

Now, let me take you through this again. We depreciate that additional $254 and, therefore, at the end of 10 years, that's the amount that's in plant and that's the amount we've provided for so the reserve zeros out, and the cost of removal would no longer be charged to the reserve because it's already been taken care of on a present-value basis. But in addition to that cost to be recognized, there is the accretion each year, which is also an expense that reduces the net income of the company. And that accretion increases over time and takes care of the total discount or $254.83 during the life of the facility. Then when the $500 of cost of removal is paid, that obligation is taken care of. Because the amount at the end would be $500 because of the interest being added each year to raise it to that level. In other words, the present value five years out is greater than the present value 10 years before the cost has to be paid.

Now, I think it's also important to note

that the total expense recorded under both of these systems is $10,500. And that's shown in the total expense column of the second table to be $10,500. That's the sum of the depreciation expense of $1,025.42 each year and the accretion over in the third to the last column. Therefore, that amount changes each year and it increases over time, not a particularly handy thing from a regulatory standpoint in my estimation. But the total cost is the same.

Now, Mr. Majoros said in his testimony, and I'll talk about this a little bit, but he talked about only paying the present value and not taking care of inflation. The inflation is specifically required under 143 and it is required, if you think about it, because you have to pay the cost of removal in whatever the dollar values are at the time that the facilities are retired. So inflation is part of the process, and it's taken into account here without regard to this discounting. The discounting must also be taken into account to cover all of the cost. In other words, that's part of the $500 of cost of removal that I assumed in this case.

Q. (MR. PEARCE CONTINUING) Just one quick question, Mr. Jeter. I think, if I heard correctly,

you may have misspoken. In the upper part where you said the figure at the bottom of the plant retirement comment, I think you said 1,000 as I heard it. I think you meant 10,000?

A. Yes, definitely. It's the total cost of the plant.

Q. Would you please comment on Mr. Majoros' discussion of FAS 143?

A. Yes. The new accounting standard will cause Montana-Dakota and other companies to change their accounting for retirement obligations. Mr. Majoros indicates that when companies do not have the asset retirement obligations described in FAS 143, quote, these costs will likely be expensed, end quote. If a company does not have such costs, I do not understand what it is that he would have them -- expect them to expense. He mentioned yesterday, if I understood it right, that the principles of SFAS 143 are that you expense the costs as they're incurred and, to the contrary, 143 is aimed directly at expensing the cost of retiring facilities during their life, over their life. And that's done as I attempted to show in the simple example. In talking about this, he talked about only the present value being recognized and that

would not recognize all of the cost.

In addition, his comments on lines 17 to 18 about measuring those costs at their present value, not the future inflated value, suggests a misconception. I don't know why, but he seems not to believe that the full amount of those costs needs to be recovered. The requirements of SFAS No. 143 are to estimate the future cash flow as expected to be spent removing facilities retired and to discount those amounts to present -- current present values. The requirements -- the required computations specifically include an adjustment for inflation. That's covered in paragraph A20 of this document called Statement of Financial Accounting Standards No. 143.

Mr. Majoros is apparently mixing the effects of inflation with the discount rate used to discount the future cash flow to present values.

Q. Do you agree that GAAP does not control ratemaking as he asserts on page 13, line 2?

A. Regulatory agencies are not required to follow the specifics of each accounting standard. Because of this, Statement of Financial Accounting Standards No. 71, accounting for the effect of certain types of regulation, provides for the

accounting necessary to reflect the effects of such regulatory actions. However, I do not think that anyone knows whether the FERC or the various state regulatory agencies will follow this new accounting in setting rates as he suggests will be done. Frequently, these agencies have decided to retain the accounting for ratemaking that they have been using when the FASB publishes a new standard. I believe that is something yet to be decided.

Q. Is FSA-143 relevant then in this proceeding?

A. Well, I believe it is. And the Commission could rule in this proceeding as to the method Montana-Dakota should use in the future for recording asset retirement obligations and the related operating expenses and how such items should be treated for ratemaking purposes. However, it is possible that the Commission will prefer to deal with the question in a ratemaking -- in a rulemaking-type proceeding involving all of its jurisdictional companies. If it is ultimately decided that the provisions of SFAS No. 143 are to be used for ratemaking, it is obvious that those provisions are relevant. If existing practices are retained, the company must still comply with SFAS

No. 143 and difference must be accounted for under the provisions of SFAS No. 71.

Now, I should mention at this point that this simple example that we went over doesn't begin to recognize the complexities of applying this in real life. The assumption, for instance, that this is a plant that is built and the entire amount is retired 10 years later doesn't apply to things like mains and services and telephone poles, and so on. Those things tend to be retired over a very long period before and after their average lives. So the computations involved -- and the document allows shortcutting so that you may be able to make the computations based on an average life even though you know that the lives of individual items in a group property will be very different. It does add a great deal of complexity to accounting for these items and I think it would add a great deal of complexity to the ratemaking function to wade through this kind of accounting each time a company asks for a rate change or each time you asked a company to change its rates.

And so I do think this is something that really is better dealt with in a rulemaking proceeding as the company has already asked to have

done rather than in a rate case. But it's relevant because Mr. Majoros brought it into the case. I responded to it only because he had talked about it.

Q. Would you please comment on Mr. Majoros' recommendations concerning SFAS-143?

A. Yes. The cost of removal charged to customers already includes the legal asset retirement obligations defined in SFAS No. 143. However, I believe the Commission may require the company to provide for similar obligations that may not meet that definition and those costs should also be included in cost to service. I certainly do not agree that, quote, The company's experience suggests that it does not have any such obligations, end quote, as Mr. Majoros states at the top of page 14. The definition of a, quote, legal obligation, unquote, in FSAS 143 is quite broad and includes entity promises to a third party, which may include the public at large, about its intention to perform retirement activities. Paragraphs A2 and A3 of the statement discuss that.

I do not agree with his comment on page 14 at lines 3 and 4 that, quote, the costs should be measured at their net present value, unquote. My Exhibit JAJ-2 shows why that shouldn't be done. If

rates are set based on the SFAS 143 procedures, the company must be allowed to recover depreciation of the present value of future net negative salaries and the accretion of the liabilities for asset retirement obligations. The sum of these two elements of cost is equal to the undiscounted cost of removal and both must be recovered to compensate the company for costs it is required to pay when costs are recorded as required under the provisions of SFAS No. 143. Here again, Mr. Majoros seems to be mixing the discounting and the effects of inflation. I believe both should be taken into account in setting rates.

One thing I'd like to add right here. We haven't talked about the rate base effects, but, obviously, if additions are made to plant to set up the obligation, you would probably need to consider whether or not those additions are included in rate base and whether that obligation is an offset. I think theoretically that would be the proper approach, but there are other ways that could be considered. In any event, I did not talk about the rate base treatment, but it would have an impact because of that growing obligation and the straight line depreciation on the other side. So it's

something to be considered.

I do not know how the five-year rolling average expensing approach Mr. Majoros recommends on lines 4 to 9 of page 14 works. However, as I explained above, if the Commission elects to follow the provisions of SFAS 143 in setting rates, the costs that need to be recovered are the depreciation present value of the asset retirement obligation, plus the accretion applicable to the present value obligation. That accretion must be expensed each year to adjust the net present value of the obligation to the new current level. The depreciation would be the same each year for any specific obligation, but the accretion would increase over time. Consequently, it would be appropriate to use -- or it could be appropriate to use a projected average amount over several years in order to allow the recovery of the total of the two parts required to be recorded under the provisions of SFAS No. 143.

If the Commission elects to continue to follow the practices it currently follows, then the differences between the two methods should be recorded as a regulatory asset or liability. The differences would be between, one, the recovery of

the estimated net salvage on the existing basis and, two, the expensing of depreciation of the capitalized present value of the asset retirement obligation, plus the accretion that must be recorded under the provisions of SFAS No. 143 beginning in 2003. In the long term, the amounts allowed would be the same, but the timing of the expense would be different under SFAS No. 143 for what -- from what it has been under Generally Accepted Accounting Principles.

In other words, like so often has happened in the past for deferred income taxes and other items that have been handled differently for regulation, there would be an adjustment made on the books to recognize the difference caused by ratemaking not being exactly in agreement with the other General Accepted Accounting Principles.

Q. Is there any basis for the depreciation recommendation shown on Mr. Majoros's Exhibit MJM-7?

A. No. Mr. Majoros has ignored the previous depreciation study with regard to negative net salvage and has also reduced the recommended provision for depreciation for 2003 by $848,000 based on a five-year average of salvage value he obtained from the company. A review of the data

shown on his Exhibit MJM-6 makes it clear that this five-year summary is not reliable for the use he made of it. If this is the five-year average he recommended on page 14, lines 4 to 8, I strongly disagree with his recommendation. As discussed earlier, there are large amounts included in the exhibit which are not recurring, such as the four-million-six sale of the office building and should not be included in any case. That transaction is unlikely to be repeated every five years. Because of this and other problems with this approach, it should not be considered.

Now, I have prepared a schedule that might help understand how that $848 amount was worked into his depreciation recommendation, and this is Exhibit 29. Most of this exhibit comes from Mr. Majoros' Exhibit MJM-7, which is near the back of his testimony. The column A just shows the average plant. And if you look at the bottom of page 1 of MJM-7, you can see that it totals to 68 million -- excuse me. I'm in the wrong column. The average balance is 68,870 -- excuse me -- 68,787,446. And I've taken the very detailed schedule and summarized it to show distribution and general separate from common. And the common facilities have to be

summarized from his schedule and that's done in note 2 at the bottom, that the schedule shows 5,381,000.03, and 1,768,000 separately on the schedule. So you must summarize those to get to the total, and then there's a little bit of amortization other in that plant and that's $299.

Similarly, on the second page of his exhibit, the annual depreciation for the year 2001 that he recommended is shown and it's been summarized in much the same manner. The 1,291,000 is the top line on his exhibit and then I've combined numbers to arrive at the general and the common plant and then the $7 of amortization plant is added and that agrees with his 2,079,802.

Then for the year 2003 on his Schedule MJM-7, page 3 of 3, this is what was being discussed yesterday with some confusion about how we got from where we are to where he recommends. I've again summarized from his schedule and here his numbers are much more summarized, but the total depreciation at that stage of his 2003 recommendation is 1,937,000 as shown at the bottom of column C. More importantly, the annual salvage which he determined on his MGM-6, which is the exhibit just ahead of the one we've been looking at, is $848,010. He arrived

at that by adding to the natural gas plant about 50 percent of the common plant to come to a total five years that he attributed to natural gas of 4,240,000. And, again, this includes that four-million-six sale of a building, but at this stage only to the extent of about 50 percent, because he has allocated part of it to electric and part of it to natural gas.

And I've taken his computation and broken it down. In that four-million-two is included the 1,444,000 of natural gas plant and when you divide that by five years, it's $288,898. And I've taken that up to show in total for distribution in general of $289,0000. That reduces the provision for depreciation in his recommendation. And you can see that happening between columns C and E. Then the rest of that 848,000 is common facilities. And he would have us deduct $559,000 of salvage with respect to common properties which have a depreciation provision of $440,000 so that the provision for common properties would end up being a negative $119,000 in a year. But that all adds into the total that he did recommend of $1,089,000, and that is shown as the very last figure on page 3 of 3 of MJM-7.

Now, I just thought it would help to run through those numbers. I apologize for the details, but I think that it does help understand what it is that's being proposed.

Mr. Majoros -- now, some of this will be a bit repetitive. Mr. Majoros also allocated the common property amounts between electric and gas utilities based on the salvage amounts for each of them separately, which is not the basis used by Montana- Dakota for the allocation of common plant costs. I think it overstates somewhat the amounts attributed to natural gas based on information I've received from the company, but I can't quantify that for you. In any case, he did not support his allocation, other than to say that it was allocated based on the amounts of salvage.

The net result of Mr. Majoros' adjustments would be a 2,172,000 reduction in the amount allowed for depreciation to an amount of 1,089,000. His proposed adjustment would be over 71 percent of the amount currently being recorded by the company. The proposed adjustment is not supported by any evidence and should not be approved. On page 14, lines 16 to 17, Mr. Majoros states that these adjusted rates, quote, are still excessive because they're based on

lives that are too short. They are conservative from the ratepayers' perspective, end quote.

I do not believe that what Mr. Majoros means by -- excuse me. I do not understand what Mr. Majoros means by conservative, but, in my opinion, his proposed rates are not conservative from any standpoint. Any further reduction would make them even less conservative. With the net salvage adjustment he made, the overall average rate he is proposing is 1.58 percent. It cannot be considered conservative in any way. It is almost certainly inadequate.

Q. Would you please summarize your testimony?

A. Yes. No adjustments in depreciation rates should be entertained until the current depreciation study is completed and an appropriate review has taken place. Current rates are based on a comprehensive study prepared in 1991 and used again in 1994. Mr. Majoros has not done a depreciation study and has no basis for suggesting the changes in depreciation rates he is proposing. His review of the depreciation rates currently in effect is entirely superficial and contains many errors. Thus, the depreciation rate should not be changed based on Mr. Majoros' proposal.

Q. Mr. Jeter, did you prepare Exhibits 29 and 30?

A. Yes, I did. Well, Exhibit 30 has information I received from the company. I prepared the summary.

Q. Right. The first page?

A. Yes.

MR. PEARCE: I will offer Exhibits 22, 29, and 30 at this time.

MR. HOBERG: Any objection?

MR. BINEK: Well, I do have an objection to Exhibit 30. According to testimony of the witness, the response to the data request that was submitted to the consultant was misleading. And may I ask a question of the witness?

MR. HOBERG: Yes.

BY MR. BINEK: Is it correct that the information was never provided to Mr. Majoros?

THE WITNESS: Well, first, I'd like to say I don't think it was intentionally misleading. I think it just happened to be because of the way those schedules were prepared. I think the company probably thought that he had all the information he needed. However, he didn't, and it was understandable, in my opinion, that he didn't

realize that that was there. However, I mentioned it in my testimony so he has been aware of it since my testimony has been filed.

MR. BINEK: But that information was never provided to him, was it, to your knowledge?

THE WITNESS: Not to my knowledge. Could have been. I don't know.

MR. BINEK: I will object to --

MR. PEARCE: What's the basis for the objection? That doesn't go to admissibility.

MR. BINEK: The information that this exhibit relates to is based on information that was requested by the Commission consultant and was never provided to him in the response to his request.

MR. HOBERG: You're not saying it's not relevant now?

MR. BINEK: I'm just saying that it has been brought into this proceeding at this time without having previously been provided to us, even though the information contained in it was requested.

MR. HOBERG: Mr. Pearce.

MR. PEARCE: Well, it's certainly relevant. That doesn't go to the question of relevancy. As Mr. Jeter pointed out, his rebuttal testimony does

state that there was, in fact, a million-four in net salvage in the services account so that would have given Mr. Majoros, I would think, the opportunity to request a data basis for that statement.

MR. HOBERG: Okay. Well, I think it's something that's certainly relevant and helpful to the Commission to have at this point. Do you need some chance to respond further to that then, Mr. Binek?

MR. BINEK: May I ask the witness another question?

MR. HOBERG: You may.

MR. BINEK: Does this information change Exhibit MJM-6?

THE WITNESS: I don't think it would.

MR. BINEK: Thank you. I will withdraw the objection.

MR. HOBERG: Okay. Thank you. I'll admit Exhibits 22, 29, and 30 then. Does that conclude the questions of Mr. Jeter?

MR. PEARCE: Yes, it does.

MR. HOBERG: Thank you, Mr. Pearce.

Mr. Binek, did you have some questions of Mr. Jeter?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Jeter, on page 3 of your testimony you state that you've testified before the FERC, the ICC and a number of state regulatory commissions on depreciation and a number of other accounting issues. Have you ever sponsored a full depreciation study?

A. No. Not the kind of study that was done in this case. I have in natural gas pipelines cases where the natural resource declines were involved and that was basically a unit of reduction approach, but I have not done a statistical curve-fitting type of studies.

Q. Okay. Thank you.

MR. BINEK: I guess could we go off the record for just a moment?

MR. HOBERG: Let's go off the record, please.

(Discussion off the record.)

MR. HOBERG: Back on the record.

Q. (MR. BINEK CONTINUING) Mr. Jeter, on page 4 you state that AUS Consulting is due to make a complete depreciation study by December 31, 2002. What is the purpose of that study?

A. Well, that information was given to me by the company, obviously. My assumption is that it would be a complete update of the depreciation work done in 1991. And, by the way, I don't know that there's any reason to expect very much change since 1991. There may be, but I don't know of any reason.

Q. Why wasn't a depreciation study done prior to the filing of this rate case?

A. I don't know. You'd have to ask one of the company witnesses.

Q. Okay. If that new depreciation confirms Mr. Majoros's suspicion that MDU's depreciation rates are too high by approximately $2 million, is it MDU's intention to file for a rate reduction?

A. I also don't know that, but I do think that could be answered by one of MDU's subsequent witnesses.

Q. Would you agree that if depreciation rates are significantly changed as a result of the study, those changes, whether up or down, should be reflected in rates?

A. Yes. I think the rate change should coincide with the changes in the depreciation being recorded by the company.

Q. So, basically, by deferring this study

until December 31, 2002, MDU will be asking this Commission to conduct two rate cases in the space of six months; is that correct?

A. If the decision were made to reflect those new depreciation results, assuming they change the amounts -- I guess I should say assuming they change the amounts significantly, then there might be a need to review that study and then adjust rates for the company to reflect whatever change that made in the cost of service, but that would obviously be somewhat limited compared to a full-blown rate proceeding, I would think.

Q. Please turn to page 6 of your testimony and read the sentence beginning on line 1.

A. By ignoring that fundamental purpose of depreciation, Mr. Majoros is effectively proposing that the depreciation rate should vary from time to time depending upon the amount of cash the company is investing in projects deemed by Mr. Majoros to be beneficial to ratepayers.

Q. Where in his testimony does Mr. Majoros make this proposal?

A. I think this is just a corollary to what he's saying. He has talked a great deal about cash flow. But he's not mentioned the fact that the cash

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requirement for plant comes when the plant is built or purchased. And that's a cash flow that's already taken place. The cash flows for depreciation are the recovery of those amounts over the life of the plant. And some of that cash may be required to pay off debt that was incurred when the plant was built. That hasn't been mentioned. But that's one of the things that must be done.

To the extent that the facilities have been built with equity funds, retained earnings, or newly acquired equity, those investors also require the recovery of their funds. Now, they may recover the funds from one plant facility, reinvest it in the company through retained earnings and invest it in another facility, but that's the way that works. And to suggest that the cash flow from depreciation is just free and there's nothing else to do with it isn't correct.

And I think the thrust of what he was saying -- although, he said at the beginning it's not the way you set depreciation rates, you don't make these cash flow comparisons, but then he proceeded to make the comparison and suggest that the customers are spending all of the money that's being spent for facilities. That's not the case.

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And I don't think he made that case and, therefore, you have to kind of assume that he's suggesting some new change in approach. That's all that whole top of that page is talking about.

Q. Would you please turn to page 6 of Mr. Majoros's testimony and read the question at the top of the page?

A. Is depreciation intended to finance plant addition?

Q. What is the first word of Mr. Majoros' answer?

A. No. Now, I just mentioned that he said that.

Q. On page 8, at lines 17 through 20, you accuse Mr. Majoros of ignoring net salvage as a component of depreciation. Where in his testimony did Mr. Majoros assert that net salvage should be ignored?

A. Well, he took it out. The net salvage that was being recorded as a result of the 1991 study was removed from his computations of depreciation, as I understand it.

Q. What do you think the 848,000 is?

A. Well, four-million-six of it divided by 2, roughly, is the sale of the building, which really

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doesn't have a lot to do with the salvage and the net salvage on services and mains. And it seems to me that if one proposes to take a five-year snapshot and divide that by five and use that over the next five years, then you must think that that is going to be repeated in the next five years. Otherwise, you're not doing something that makes any sense at all.

Q. But is that net salvage?

A. I don't think it's going to be repeated in the next five years.

Q. Is the number that Mr. Majoros used net salvage?

A. It is, but it's not salvage in the sense of a depreciation study reflecting the salvage applicable to the facilities involved over the life of the facilities. It gets away from the whole concept of depreciation and the concept under the new Financial Accounting Standard in 143, which is clearly not to recognize this thing based on some average of some short period. It's to recognize them based on the life of the facility and the expected cost at the end of its life to remove those properties or the expected credit in the event that there is, in fact, positive salvage.

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Q. In fact, does Mr. Majoros include net salvage in his final depreciation recommendation only as positive rather than negative salvage?

A. Yes. Well, he included net salvage and it was positive. I mean, because of the period he selected and some of the extraneous items included in that period.

Q. On page 9 you take issue with Mr. Majoros' observation that the Supreme Court found that excessive depreciation resulted in extraction of capital contributions from ratepayers. Is it possible to have excessive depreciation of the original cost of an asset or group of assets?

A. I have to know what you mean by "excessive."

Q. How would you define excessive depreciation?

A. Well, if you mean is it possible to have estimates of the life of a facility that turn out to be wrong and turn out to be wrong because they're too short, then some would say that would generate an excessive amount of depreciation expense in the ratemaking situation revenues to cover that expense.

But the excess depreciation in that situation, and this is assumptions that -- we say

the life is going to be 20 years and then we discover after the plant has been in service for 10 years, that it's going to be 15 or 25. If it's going to be 25, then you could say that was excessive. It may not have been. The life used during that first period might be exactly right in terms of the best estimate you could get, but when you get better estimates of what the life is, you should adjust. And the typical method of adjusting depreciation is over the remaining life of the facility.

Q. If a utility depreciates a category of plant on the basis of 140 percent negative net salvage when the negative net salvage is, in fact, only 15 percent, would that constitute excessive depreciation?

A. It might if you accept your assumption. Those are both assumptions. One of them is an estimate made by somebody using judgment and historical facts, and so forth, and the other is just an assumption of 15 percent being the right answer. If that 15 percent were to be the amount determined in a new depreciation study, then I would say that you could say that that had been excessive, but only based on saying we made a wrong estimate in

the past, not based on the fact that we know more now and we're adjusting our estimate. So there's a fine line between whether it's really excessive or it's excessive relative to what you would be thinking it should be in the future.

Q. On page 11 of your testimony you purport to demonstrate that since 1995 the depreciation which Mr. Majoros claims to be excessive would by now have paid for itself in the form of rate base deductions; is that correct?

A. In effect, that's a short way of saying it, I guess.

Q. Did you quantify your rate base deduction by multiplying Mr. Majoros' $2.172 million depreciation expense adjustment by the eight years that have transpired between 1995 and 2002?

A. Yes.

Q. Mr. Majoros' correction is to eliminate the negative salvage and to amortize positive salvage over five years; isn't that correct?

A. That's my understanding, yes.

Q. What makes you believe that Mr. Majoros' adjustment, if applied in 1995, would have amounted to 2.172 million?

A. Well, I emphasized the word "rough" when I

started on this. I did not attempt to go back and figure out what Mr. Majoros' adjustment would have been had he made it in '95. I think that's clear from the way I described it. But I would admit that had he made a similar adjustment back in 1995, it probably would have been somewhat less because there was less plant at that time. I think. Now, I did not do that. This is very rough. It's an example more than anything.

Q. Well, Mr. Majoros would not have included the $848,000 in positive salvage because it didn't occur until 2001; isn't that correct?

A. I don't know what the positive salvage or negative salvage would have been or what five-year period he would have chosen.

Q. MDU's gas distribution plant was a smaller total amount in 1995; would you agree?

A. Yes. And I already said that would have an impact. I did not calculate it.

Q. And so the elimination of negative net salvage would have been a correspondingly smaller amount, wouldn't it?

A. Probably. I don't know. I haven't looked at it.

Q. Wouldn't the result have been a rate base

offset somewhat smaller than the 17.376 million that you ponder on line 4, page 11?

A. It might very well have been, yes.

Q. On page 12 of your testimony you argue that it would be inappropriate to calculate theoretical depreciation reserves to determine whether a reserve excess or deficiency exists. Are you familiar with the term "remaining life depreciation"?

A. Yes.

Q. Would you please describe what that term means?

A. It involves determining the life of the facility, an estimate of the age of all of the facilities, and thereby arriving at a remaining number of years that you would expect those facilities to exist before they're retired. And then converting that to a rate using the total cost of the facility less the depreciation reserve as of the same day.

Q. Does MDU use remaining life depreciation?

A. Yes. It's my understanding that that's been done based on what I've read in the 1999 -- '91 study.

Q. Doesn't remaining life depreciation effectively amortize any reserve excess or

deficiency over the remaining life of each category of plant?

A. Yes. That's why most depreciation studies don't include trying to figure out what a theoretical reserve will be. It's taken care of over the remaining life in any event.

Q. Earlier you discussed R3 Iowa curves. Do you know what a generation arrangement is?

A. Yes. I don't know that I could describe it. I've read quite a little bit about it.

Q. How do you calculate an average remaining life?

A. Well, it's calculated based on the retirement dispersion that is determined using the curves after having determined from the existing data about plant what is the best fit. In other words, the Iowa curves are based on actual evidence of what the lives of various kinds of facilities were. And it was found that using those curves, you could ordinarily find a fit for almost any sort of -- as they referred to them, industrial property, to one of the various curves, the right, left and symmetrical curves.

Once that's done, you have a dispersion of the asset retirements that you would expect and you

can determine using the remaining life of those that have not already been retired what the remaining life would be to use in that situation. Now, that's a pretty rough discussion of that. I have not done that kind of a study. So I understand what's done, but I'm not an expert on using those studies to do what's done other than on a very broad basis.

Q. What is an O curve?

A. I don't know.

Q. Do you know why an O curve is different than an R curve?

A. Did you say L?

Q. An O.

A. No. I think there have been some additional curves developed. I'm not familiar with the O curve.

Q. On pages 13 and 14 and 15 you challenge Mr. Majoros' discussion of service lives for mains and services. Did Mr. Majoros recommend any changes to the service lives underlying MDU's current depreciation rates?

A. No.

Q. From the standpoint of its impact in this case, your criticism of Mr. Majoros' service life discussion is irrelevant; isn't that true?

A. Well, I think it's relevant because I would hate to think that anybody would seriously contemplate a change in depreciation rates based on the 116- and 74-year lives he determined with the only computations he did with respect to service lives. I certainly agree he did not reflect those in his final recommendation. To that extent, it's irrelevant, I would agree, but I don't think I could just not comment on it when I don't think it should be used.

Q. On page 21 you argue that if the Commission elects to apply FAS 143 to MDU's cost of removal, there would have to be two elements of expense; one, the depreciation of the annual present value of future expense and, two, the accretion of the asset's value each year; is that correct?

A. Yes.

Q. You also contend that over the life of the plant both methods recover the same amount; is that correct?

A. Yes.

Q. Do they recover that same amount at the same rate --

A. No.

Q. -- that is, is one method front-loaded more

than the other?

A. The SFAS 143 method would recover plant by increasing amounts over time. It would not be front-loaded. It would be back-loaded.

Q. Okay. And the present method is front-loaded?

A. The present method is -- I think I would call it level. There are methods --

Q. Well, if you have the other method being -- what did you refer to -- back-loaded, then isn't this more front-loaded?

A. In other words, there is more and more expense over time each year. In the present methodology there's the same amount of expense each year, unless there are changes in estimates. You would have depreciation that is level with respect to it. Now, we should be careful about this, because inherent in this discussion is a discussion about a piece of plant that is installed and then later it's retired, all of it. We have many pieces of plant here that have varying lives, with an average life near the center of that long dispersion period of retirement. And if you superimpose SFAS 143 over that kind of a situation, I'm not sure I could even answer the questions, but I think it

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would still involve back-loading or growing expense over time with respect to any property or group of properties. I frankly haven't looked at that.

Q. Is Montana-Dakota Utilities subject to FAS-143?

A. It is subject to it when it becomes effective, yes.

Q. Isn't it effective now?

A. No, it's effective -- well, it's effective for some companies now, but for companies with calendar-year financial statements, it's effective for next year.

Q. Does MDU intend to implement FAS 143?

A. I certainly think so. They won't be able to file financial statements if they don't.

Q. So you agree that the company is going to have to comply with FAS 143 and you talked about the complexity of FAS 143. But since the company does have to comply with it, the records will be available for ratemaking purposes; isn't that correct?

A. Sure.

Q. I'd like to have you turn to your JAJ-2. If the company did not have a legal obligation for the $500 removal, then the bottom half of your table

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would be incorrect; isn't that correct?

A. Well, the entire exhibit would be incorrect if they don't -- now, excuse me. You specifically put the legal obligation in there and I now understand your question better. That could be true. And as I mentioned in the testimony, the legal obligation is fairly broadly defined. And if we think about what that means in terms of what a company has to do, it's a little hard to imagine very many things that a company would actually remove at the end of the life if they're not required to do so.

Now, there are a lot of people that are making requirements of companies to do that kind of thing. The regulatory agency could probably rule on such things and that makes it become a legal obligation, as I read the new standard. The cities that they deal with who were putting things into the streets and alleys, and so forth, may have something to say about whether those items are removed when they're retired. And it seems to me that with the increased concerns of environmentalists, that's all going in the same direction. We are going to have more and more requirements, rather than less. But if there are things that the company feels it must

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remove, even though there is no legal obligation to, it would seem to me they would be very limited. I mean, I don't know why they would remove anything if they are not required to do so.

Now -- and it isn't just removal. In some cases they could be required to be do something to pipe that's in the ground, for instance, to make it safe, fill it with an inert substance, for instance, or do something like that, and that's cost of removal as well, even though technically you're not removing it, you're taking care of a cost that's your obligation at the end of the life, if you are doing that in accordance with some legal requirement as defined.

Q. In your earlier testimony you said that it would cost the same to remove a service as the original cost. Do you think that this company digs up an existing service when it replaces it?

A. I don't know, but I should straighten out what I said there, if you didn't hear me earlier. What I meant was, it would cost the same in time. The effort to remove a service might be the same as it is to put it in in the first place. In fact, it may be greater because nowadays a lot of services are plowed in and I don't think you can plow them

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out if you are required to do the removal.

But, in any event, what I really was talking about was not cost the same, but take the same amount of effort, and if it took the same amount of effort, my whole point with that was it might cost a great deal more because of inflation.

Q. But only if they have to dig up?

A. That's correct. And it isn't enough to determine what it would cost. You've got to determine whether or not it has to be done and, if so, when and under what circumstances.

Q. And isn't that one of the important concepts of FAS 143, is that it shouldn't be shown as salvage unless there's an obligation to remove it?

A. Well, as cost of removal.

Q. Okay.

A. I mean, actually, 143 does not discuss salvage. Salvage is to continue to be accounted for.

Q. I used the wrong term. Cost of removal.

A. Cost of removal is what it's aimed at. And it definitely is saying if you have an obligation because of the use of the facilities, then you have to recognize it. And I don't think there are very

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many companies that are in business for a profit that are incurring and paying costs of removal that they don't have to pay. I mean, I just don't think that's very --

Q. I would agree with that. Are you familiar with the concept of insertion?

A. Not unless you define it for me.

Q. That's okay. Are you familiar with the concept of abandonment in place?

A. Yes.

Q. Okay. What is that?

A. Well, I earlier talked about abandoning buried pipe, for instance, and in some cases that probably will be allowed and it will just stay where it is. It won't be removed. It may require something being done to it if it is, in fact, abandoned. I know, for instance, in gas transmission facilities, cross-country lines, they're trying to provide for all of the things they're going to be required to do because some of that line is very large and if it decays and rusts out, and so forth, you can have a big cavity there, and so they're faced with some significant amount of costs, but not to remove the line necessarily. They may leave it there, but shore it up so that it's not

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going to be a problem over a long period of time in the future.

Q. That's when they replace it, right?

A. Well, replace or abandon. If it's abandoned, that would be more likely. If they replace it, I think in the transmission facilities they typically loop it and put another piece of pipe beside it so they wouldn't necessarily retire it, but if they are retiring it, they might leave it underground or because of right of way and other considerations, they might actually take it out and replace it with other pipe.

Q. I'd like to now talk a little bit about this building sale that you've discussed at length.

A. Yes.

Q. Where was that building?

A. Downtown Bismarck. It was the Schuchart building, as I understand.

Q. When was that building sold?

A. It was the first year of that period, so it must have been in 2001. That's when the sale was recorded. I'm not sure if the accounting -- I would say in as large a transaction as that, that's the year it happened also.

Q. What was the original cost of that

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building?

A. I don't know.

Q. When was the building purchased?

A. I don't know.

Q. Why was it sold?

A. I don't know.

Q. What was the sale price?

A. The only information I have on that is the sale price was equal to the net book value at the time of the sale, which means the total cost of the facility that the company has paid for it, less the accumulated depreciation, was equal to the sales price.

Q. And what was that net book value at the date of sale?

A. Well, it was four-million-six or so. Exact amount I'm not sure.

Q. Who was the building sold to?

A. I think it was sold intercompany with respect to MDU Resources. Now, I'm not real familiar with that, but I believe it was sold to an affiliate, in any event. Might actually have been another division of the same company. I'm not that familiar with their corporate structure.

Q. How did the sale price come to match the

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net book?

A. By agreement, I assume. I don't really know that.

Q. Do you know if MDU tried to obtain the market value?

A. I have no idea.

Q. Would you please provide the journal entries in the company's books that relates to the sale of this building as a late-filed exhibit?

A. I don't have access to those. I think somebody else that's testifying after I am can.

MR. HOBERG: Is this a request you are making of the company?

MR. PEARCE: I think Mr. Keller would be an appropriate witness for that.

MR. HOBERG: Do you want to reserve that question for Mr. Keller?

MR. BINEK: I can reserve that question, unless the company is willing to provide the information.

MR. PEARCE: It's certainly willing to provide, but I think he can clarify exactly what you want and describe it by official title. So I think it might be easier to put in through Keller.

Q. (MR. BINEK CONTINUING) You state in your

testimony that the other 48 states do not use a current period recognition of net salvage; is that correct?

A. I said that this morning, but that's an assumption on my part based on the testimony to the effect that Pennsylvania and Kentucky are doing such things.

Q. I'd like to have you turn to page 157 of the 1996 NARUC manual that you've been referring to.

A. Yes. I'm sorry. What was the page?

Q. One fifty-seven. Would you please read the two paragraphs, the first beginning with the statement, "historically, most regulatory commissions"?

A. Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that since most physical plant placed in service will have some residual value at the time of its retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning are the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from

the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

Some Commissions have abandoned the above procedure and moved to current period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates with the cost of removal being expensed in the year incurred.

Q. Thank you.

MR. HOBERG: Mr. Binek, do you have a number of additional questions?

MR. BINEK: No, I don't believe so.

MR. HOBERG: About how many do you have left?

Q. (MR. BINEK CONTINUING) How often should depreciation studies be done?

A. Well, it's a little bit varied around in various jurisdictions. Many jurisdictions require that studies be done on a periodic basis and I think five years would be fairly typical of that. Others

don't make any requirements and I think some companies go longer times between. Now, they may have looked at the facilities and decided that there aren't any significant changes in what they are seeing with respect to the lives of facilities, and so forth in their records and, therefore, elect not to do it quite as often. But I would say probably in some cases even three years, but depreciation studies are expensive and so three to five to longer periods are probably fairly typical, but with attention to it much more often than that in terms of just deciding whether or not it is required.

MR. BINEK: I have no further questions.

MR. HOBERG: No further questions. Let's take a luncheon recess here. I'm wondering, though, what we should take? An hour? Commissioners request an hour.

COMMISSIONER WEFALD: 1 o'clock.

MR. HOBERG: Let's be back at 1 o'clock.

(Lunch recess was taken.)

MR. HOBERG: Okay. We're ready, back from the luncheon recess, and I think we were -- we just completed the cross-examination by Mr. Binek.

So, Commissioner Reinbold, do you have any questions of Mr. Jeter at this time?

COMMISSIONER REINBOLD: I do not.

MR. HOBERG: Thank you. Commissioner Wefald, do you have any questions?

COMMISSIONER WEFALD: I have one.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. In your testimony you say that the company -- you understand from company personnel and from the exhibit you prepared has recorded 1.4 million of negative net salvage -- of net negative salvage for services during the years 1995 though 2001?

A. Yes.

Q. How does this number of actual cost of removal of services in five years compare to the plant removal costs of service which were figured at 140 percent depreciation?

A. I'm sorry. I don't know that because I didn't have the retirement date that goes with those costs of removal. I think that would be something to look at, but I just did not do it.

Q. So who would I get that --

COMMISSIONER WEFALD: Can MDU provide that information to the Commission as a late-filed exhibit?

MR. HOBERG: Mr. Pearce, did you understand the question and hear it?

MR. PEARCE: I'm not exactly sure we understand the question. Give us a moment here. We'll certainly do the best we can. We'll have to check with the other MDU personnel who are not here, but we'll certainly try to prepare what we understand that request to be.

MR. HOBERG: So it's possible you'll be able to file a late-filed exhibit on that?

MR. PEARCE: Yes.

MR. HOBERG: Okay. I don't think we've had any other late-filed exhibits to this point so that would be Late-Filed Exhibit 1, if you will, that information.

Q. (COMMISSIONER WEFALD CONTINUING) If this number were less than the planned removal cost of service at 140 percent, do some Commissions take a look at actual removal cost and use those versus what the company has planned through depreciation?

A. Well, I would say that most would look at the actual relationship between the cost of removal and the cost of the facility as they're retired, but you almost have to deal with this by vantage. In other words, if some mains were put in in 1968, say,

and removed in 1998, you would expect that to be something like what they had estimated in the depreciation study.

Q. In this case we're talking about the services, not the mains.

A. Okay. Well, and this would be true of either. Let me say services then. They would keep track of how many dollars of plant were involved adding services each year and you almost have to look at it year by year when the retirements are coming out, because, for instance -- and this isn't quite so true for services -- but if something goes in and then two or three years later is taken out of service for one reason or another, I mean, property is destructed or a road moves, any number of things can cause that, then you wouldn't necessarily expect the cost of removal to be what they estimate for the whole life of that group of assets in that vantage.

Q. Well, for example, I live in an older neighborhood built in 1915, so we started out with a coal furnace in our house, which was converted to natural gas when natural gas was brought to Bismarck. Do you know the year natural gas was brought to Bismarck?

A. Well, I understand it was quite early

because I was talking to somebody about the fact that natural gas came into Nebraska in either the late '40s or early '50s, and I understand it was earlier than that here, so it may have been.

Q. So let's say it was even 1950 and at that point then my service main was probably installed to my home.

A. Yes, I would -- it would have to have been.

Q. I've lived in the house since 1970 and there hasn't been any change in my service main during that time so I've been in there 32 years now. So are they anticipating someone is going to be coming out to my house in a couple years and taking out my service main that's underneath my cement driveway?

A. I don't know how long the kinds of equipment that might have been installed in the 1950s would last, but there's a range of time over which assets are retired and so a 50-year sounds like a long time, but that range may go -- assuming that the average life is 50 years, you could have some of them that last 90 years and some 10, but it would be over that whole range and many of them would be clustered around the 50-year point and it might make sense for that facility to be removed or

replaced, or both, because of safety or some other requirement, depending on the condition.

It's hard to answer it any better than that, but I think there are those kind of considerations and in a situation like that, assuming that you would continue to use the house and want gas service, there might just be a new service put in and the existing one removed at the same time or secured and not actually taken out of the ground. Because I suspect that 50-year-old pipe is not going to be worth much to anybody. First of all, if you're removing, retiring it, more than likely there's a reason for that and it's not very good stuff and so you wouldn't expect to be able to use it.

Q. So your answer to my question is that there is more to look at than the actual removal cost versus the planned depreciation removal costs?

A. Well, I think you can look at those things. I just believe you need to look at them in more detail and get down into it and know exactly what it is that you're looking at because there would be varied reasons for things once you got into the details and I think that it's necessary to look at those details.

But your thought of comparing what's actually happening in cost of removal and the relationship of that to the cost of the facilities that's being retired is exactly on point. I think that's what would be done in a depreciation study in connection with trying to estimate what those amounts would be. That's almost exactly what they would be doing. But it would be done at a more detailed level than on a broad overall basis because you don't learn as much unless you get down into those details.

Q. What if the Commission were to say to MDU that we should wait until they get their new depreciation study before we would proceed with this case?

A. Before you would complete the case?

Q. Mm-hmm.

A. I think that's a policy decision on their part. I couldn't answer that. My suspicion is they wouldn't want to do that, but I don't know.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, did you have any questions?

COMMISSIONER CLARK: I have none. Thank

you.

MR. HOBERG: Thank you. Any further questions of Mr. Jeter?

MR. DILLER: I just have one that I might add on to Commissioner Wefald's.

Since we're getting the cost of removal for service signs, I think you said five years, Commissioner. Did I hear that right?

COMMISSIONER WEFALD: We know they have put on the record 1.4 million is their cost of removal and I asked how that would compare to what they had planned in their depreciation study.

MR. DILLER: I think it would be helpful, too, along with that late-filed exhibit, if we could have the number of service lines retired during the last five years.

MR. HOBERG: You want that as a separate exhibit?

MR. DILLER: However they want to do it.

MR. HOBERG: Late-Filed 2 then. Is that possible?

MR. PEARCE: Sure.

MR. HOBERG: Thank you, Mr. Diller. Any further questions of Mr. Jeter? Mr. Binek?

MR. BINEK: Yes, I have one.

FURTHER CROSS-EXAMINATION

BY MR. BINEK:

Q. You said that you incurred 1.4 million in cost of removal; is that correct?

A. Yes. Now, I think somebody said five years. That data was actually from '95 to 2001, so it's actually seven years.

Q. Okay. But those were the costs incurred by the company. What were the amounts that the company collected for salvage?

A. I think that's the same question as we were just discussing. I don't know because I don't know the amount of the plant that was retired, nor how old it was so I can't answer that question, but I do think that that would be answerable with the additional data in the late-filed exhibit, if I understand what's been asked for.

MR. BINEK: I would ask that that be included in that data.

COMMISSIONER WEFALD: And, actually, if it's supposed to be seven years, I would appreciate that. I'm sorry. I didn't realize. '95 through 2001 is seven years.

THE WITNESS: That doesn't match his exhibit, but that's what the data was that I got.

MR. HOBERG: Mr. Pearce, did you get that?

MR. PEARCE: Yeah, that's fine. I have one redirect question, too.

MR. HOBERG: Okay. Does that conclude yours, Mr. Binek?

MR. BINEK: Yes.

REDIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Jeter, in the course of your cross-examination you were asked to read two paragraphs from a NARUC manual. Would you comment on the content of that paragraph and add any additional information you might wish?

A. Yes. The sense of that was that their gross salvage and cost of removal are to be reflected in depreciation rates and that it's difficult to estimate and that some Commissions have abandoned the procedure and moved to a current period accounting. And I just want to say that I think that's absolutely wrong for the reasons I talked about earlier, because it doesn't reflect those costs over the proper period and get the right customer charged with those costs over the life of the facility that's involved.

And then I'd also like to read in the

paragraph that followed the ones that I did read. It says, Determining a reasonably accurate estimate of the average or future net salvage is not an easy task. Estimates can be the subject of considerable discussion and controversy between regulators and utility personnel. This is one of the reasons advanced in support of the current period accounting for these items. When estimating future net salvage, every effort should be made to ensure that the estimate is as accurate as possible. Normally, the process would start by analyzing past salvage and cost-of-removal data and by using the results of this analysis to project future gross salvage and costs of removal.

And the reason I'm very much opposed to this is the reason that the Financial Accounting Standards Board has issued its new SFAS 141. They are deadset on recognition of these costs over the life of the facility, not at the end of the life. And if you think of that in terms of a nuclear generating station, you can see why. Because if you wait until the end of the life of a nuclear plant and then put that cost of removal into the rates at that point, you're charging the future customers, if you can recover, rather than those that benefited

from the use of the nuclear plant during its life. And that's just plain wrong, as far as I'm concerned, from a regulatory standpoint. And it's easier to understand with a nuclear plant, but it's the same thing with others. It's much more difficult to estimate some of these lives of mass properties where they retire over long periods of time, but it's still doable and it's certainly worth the effort in order to get the costs recognized at the time that those properties are serving customers.

MR. HOBERG: Mr. Jeter, did we get in the record what you were reading from again?

THE WITNESS: I'm sorry. I was reading from page 157 of the NARUC Public Utility Depreciation Practices Manual, dated August 1, 1996.

MR. HOBERG: Thank you.

THE WITNESS: And it was -- the part I read was the fourth paragraph on that page and it continues on page 157 and it continues on the next page.

Q. (MR. PEARCE CONTINUING) Just one thing. I think you misspoke. You said 141 and you meant 143, FAS?

A. Did I say 141? I'm sorry. Yes, SFAS 143.

MR. HOBERG: Mr. Binek, do you have another question?

MR. BINEK: Yes, I have one more.

RECROSS-EXAMINATION

BY MR. BINEK:

Q. If you use recent past salvage as a guide, would the overall net salvage be positive or negative?

A. Well, recent based on Mr. Majoros' exhibit would be positive salvage.

MR. BINEK: Thank you.

MR. HOBERG: Anything further then of Mr. Jeter? Thank you, Mr. Jeter.

MR. PEARCE: I'll call Craig Keller.

MR. HOBERG: Mr. Keller, you testified yesterday; is that correct?

THE WITNESS: Yes, I did.

MR. HOBERG: I just need to remind you then that you're still considered to be under oath.

THE WITNESS: Yes.

MR. HOBERG: Mr. Pearce, please.

CRAIG A. KELLER,

having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Keller, you previously identified yourself and gave your position with the company, I think, yesterday. And you have filed some rebuttal testimony in this case. I would ask if you could simply summarize the main points of your written rebuttal testimony and then add anything that you feel is a part of rebuttal to the staff's case.

A. Sure. I would like to start by addressing the capital structure and costs of debt that was used by Mr. King. And I'd like to start by just making sure that when we use the name MDU Resources Group or Montana-Dakota, that we understand that they're the same legal entity and that the balance sheet is the same. MDU Resources Group in essence is really a separate cost center within that legal entity where we track the costs for our resources group and we allocate those to our different businesses. So, you know, when we talk about Montana-Dakota, we talk about MDU Resources Group's balance sheet, we're talking about the same thing.

And I think it's in this statement, Statement A, where Mr. King tries to, I should say, connect the dots between Centennial's debt and

MDU's. He looks at Statement A and on page 1 where we have the unconsolidated balance sheet of MDU Resources Group and he's using that to connect to the consolidated footnotes in that same schedule. And the difference between a consolidated balance sheet and an unconsolidated balance sheet is that MDU's unconsolidated balance sheet does not reflect the assets and liabilities of the subsidiary companies. It only reflects the investment MDU has made in those companies. On the consolidated balance sheet it would reflect all the assets and liabilities of those companies and in essence you'd have a grossed up balance sheet of all the assets and liabilities of the corporation.

In Statement A, page 1 of the balance sheet, that only reflects the unconsolidated balance sheet of MDU. However, when we go to pages, I think, 3 through 29, which are the footnotes, those reflect the consolidated footnotes of the company, the ones that were attached to the company's annual report. On page, I think, 11 of that, footnote 6, it lists the long-term debt, including Centennial's, on which it would be listed because it's a consolidated balance sheet. And Mr. King implied that that debt was part of the unconsolidated

balance sheet of MDU and that's not correct. That would be Centennial's debt and is not really part of Montana-Dakota's individual balance sheet.

Yesterday King made a statement that MDU was attempting to build, quote, a firewall around MDU to separate the debt of Centennial from MDU. And that is exactly what MDU is trying to do. And I'd like to explain to you the reasons for this and why I believe the Commission should support MDU in its efforts. In questioning Witness King, Commissioner Wefald raised a concern as to the negative effect a bad business decision at Centennial, one of its companies, would have on MDU and its cost of debt. And, quite frankly, MDU, as well as the rating agencies, are also concerned about this. The concern is that bad decisions made at Centennial Energy or one of its subsidiary companies could cause default or cause a bankruptcy that could roll up into Montana-Dakota or MDU. And what we're trying to do is prevent this from happening.

One of the things that -- we heard Mr. King use the term "firewall." The same kind of philosophy or term is used by the rating agency. They call it ring fencing and attorneys call it

bankruptcy proof, but what we're trying to do is protect the assets and the customers of MDU from our nonregulated businesses. And the concern we have is that in the event that there were a default at Centennial or one of its companies, we do not want that to cause a default of MDU. Likewise, if there was a bankruptcy at MDU -- at Centennial, we do not want a bankruptcy judge to have the ability to collapse the corporation and provide the creditors of Centennial or the subsidiaries of Centennial, we do not want them to have access to the assets of the utility. We want to protect our customers from this happening.

And there's some things we can do. And one of them is we need to keep separate and distinct books from Centennial, which we currently do. We need to conduct the business of the utility in a manner that is clearly distinguishable and separate from the operations of Centennial, and we do that. MDU does not participate in a money pool or comparable intercompany fund arrangement with Centennial. This means that MDU does not commingle its corporate funds with those of Centennial. It means that MDU and Centennial maintain their own distinct and separate credit facilities. Neither

have access to the other's credit agreements. To further strengthen this point, MDU does not lend funds or otherwise extend credit to Centennial, and Centennial does not do the same back to MDU.

Mr. King stated yesterday in his testimony that all debt is raised and issued by MDU and is simply pushed down to Centennial and the subsidiaries of Centennial, and this is not correct. A first mortgage lien of MDU's electric property and gas is what's used to secure the long-term financing for MDU. The only property that can be pledged under this is qualifying utility property, and this is our electric and gas property. Centennial cannot pledge its nonregulated assets under this agreement and it cannot access this agreement. There are no cross-default provisions in this credit facility where a default at Centennial would trigger a default at MDU. And there are no requirements from MDU from the capital to advance funds for Centennial or a subsidiary of Centennial under this agreement.

Centennial's credit agreements are separate from MDU and require Centennial to use the funds that they raise under this agreement to conduct the operations of Centennial and the Centennial subsidiaries in order to preserve Centennial's

financial integrity. And, simply stated, if we allowed MDU to have access to the funds raised under Centennial's financing agreement, we in essence would give a bankruptcy judge an opening to take and collapse the company in the event of bankruptcy by Centennial to give those creditors of Centennial access to our assets. And they would do this under the assumption that we may be using these funds to benefit MDU at the expense of the Centennial creditors. So we do not want to do this.

And to further strengthen this position, we make it not only clear to anyone that has borrowed money to Centennial that MDU does not guarantee the debt, but nowhere in those instruments do we allow the name MDU to be used in Centennial's credit agreements.

I'd like to comment on Mr. King's Exhibit 16 yesterday. What that was, it was an exhibit showing the working capital of Montana-Dakota. And on there he had materials, fuel costs, prepayments, customer advances. And he made the comment there were material differences in these accounts. In my rebuttal testimony I stated that these accounts remain relatively constant and support the long-lived assets such as property and plant. And I

further stated it is the Company's policy to finance our long-lived assets with long-term debt. This helps mitigate exposure from interest rate volatility over the asset's life.

Now, looking closer at this exhibit, you'll see that from June to July there's a big decrease in the customer advances. And this decrease accounts for essentially most of the variance in the schedule. And this was a result of a refund of a customer advance that was out of the ordinary. It was an abnormal customer advance and it does not reflect normal activity. Without this adjustment in here, the fluctuations would be minimal and it would really be insignificant to the rate base.

You know, I find it interesting that Mr. King himself is inconsistent in his method of determining capital structure with that of setting debt cost. In arriving at debt cost, Mr. King uses the argument that all debt is commingled. Mr. King uses the argument because it provides him with the lowest cost on debt. If Mr. King makes his argument and assumes that debt is commingled, then it would only be logical and consistent to assume that equity, as well as all capital, is commingled. To follow through with his arguments and logic,

Mr. King should then have used the capital structure of the consolidated MDU resource company versus just the capital structure of MDU.

Now, if you look at the consolidated capital structure, the equity portion is over 60 percent, compared to the capital structure just of MDU, which is roughly 50 percent equity. However, if you were to use a consolidated capital structure, you would have to increase the costs of capital. So he chose to ignore. What he does, he picks the capital structure when it fits him and he takes the weighted average wherever it provides the lowest cost of debt, and it, in my mind, is arbitrary and inconsistent.

In testimony yesterday Mr. King stated that the Commission should use December 23rd, 2001 as a base for the capital structure. As I point out in my rebuttal testimony, North Dakota Administrative Code 49-05-04.1 allows for projected test periods. MDU extends a considerable effort to develop budgets and forecasts from which to make decisions and guide our organization. Mr. King did not provide any testimony or evidence to suggest or dispute the accuracy of these projections and, in fact, Mr. Majoros accepts the projected revenue from this

2000 test period in his testimony.

MR. HOBERG: I'm sorry, Mr. Keller, what was the code section you referenced?

THE WITNESS: 49-05-04.1.

MR. HOBERG: That would be the North Dakota Century Code then.

THE WITNESS: Okay. I stand corrected.

MR. HOBERG: Thank you.

THE WITNESS: In setting capital structure and determining debt cost, Mr. King's methods and arguments are illogical, unfair, and even ignore North Dakota's Century Code. Mr. King's attempt to commingle debt with that of Centennial and that of MDU is not only bad public policy, but it also increases the financial risk for our customers. The capital structure that MDU has filed is correct and should be used.

I'd also like to just briefly document addressing comments made on 143. I think Mr. Jeter has done a very good job of addressing the company's position, but the industry itself -- when I refer to industry, I'm really talking about EI and AG, which are associations for electric and gas industries. They are recommending that we take a go-slow approach to FAS 143, and we agree with this. The

methods we use now are straightforward. They're easy to understand and they're easy to implement.

MDU will need to adopt and comply with FAS 143. We're still studying the effects of that and we don't know the ultimate outcome, but we believe that any changes that are required because of that will have little or no effect on MDU or its customers. And the reason we say that is because if there's any difference between what's required in 143 versus what we do for regulatory purposes, we will defer on said regulatory assets as allowed under FAS-71.

I also thought it would be appropriate for me to talk a little bit about the negative salvage or positive salvage and the removal of costs. I worked in the tax department for a number of years, and through the years I spent a lot of time combing through the depreciation reserves for MDU. And I've looked back over probably, oh, early '70s to late '80s. And over all that time, when I looked through those, when you see large amounts of positive salvage, it almost always resulted from one of three things. Either there was a sale of an asset or some insurance proceeds that we received or we traded an asset for another asset.

If we looked at the period we're talking about, there was a sale of an asset and that was the Schuchart building we talked about. And that was sold at net book value. Mr. Majoros refers to that and he focuses on that part of the reserve where the salvage shows up. However, there's also offsetting adjustments in the reserve for the retirement of the asset as well. So the effect was that there was no gain or loss on that asset. And while there shows large amounts of salvage, there really -- all the company did was collect its cost for that building from the affiliate to which it was sold.

Insurance proceeds in this time period, we received insurance proceeds due to the hailstorm we had in 2001, and we received money for a lot of vehicles and other stuff that was damaged. At the end of it, when we did some repairs and stuff, we had money left over. We took that money and we credited the reserve salvage for that so our customers would benefit in the future from that, rather than take any of that money to the bottom line for the shareholders. That money will help lower depreciation rates going forward.

On trade-ins, we have a program where we trade in our equipment, some of our equipment every

other year. It's a very effective program and we can trade equipment in and get brand-new equipment for almost little or no cost. The effect of this is that when you look at a reserve, you'll see large amounts of salvage going in. In effect, all it is, we're trading in. We're showing the salvage on one hand. We're replacing a piece of equipment so we have a property addition on the other hand. There's really no net increase in plant because of those transactions. It just shows up as salvage.

Removal costs, when we talk about mains or services, in talking to some of our people our normal policy -- or I should say a normal retirement of a service in our company would be that we would take, we would cut the service -- the riser off, which would be next to the customer's premises. We would cut that off below the surface and cap it with a weld or if it's plastic, we put a seal on there. But we also will cut it at the main, and we'll cap it there as well. But we just don't cap and leave the whole service line in the ground. The policy or the procedure we usually do is, we take and remove at least a portion of that service line to move it beyond the public easements, and we do that for some reasons. One of them is that we don't want gas flow

in this thing. We don't want the exposure of gas flowing through there. We also don't want dead lines sitting next to the -- you know, to the mains. We don't want the risk that someone may inadvertently mistake a dead service line for the main and think that they've located the proper line, and we don't want to have a situation with our line locators going out there and accidentally marking the wrong line.

The cost can be quite expensive to do this here, because what you're usually doing here, what my people are telling me, is a lot of times when you are doing removing, you're excavating and repairing under concrete and asphalt so the cost can run pretty high. And I think those contribute to the $1.2, $1.4 million that we're seeing in there. The other comment they're saying is that there are now rules that require the company to maintain detailed records of our dead lines. And so our concern or our thoughts are going forward is that rather than seeing a decrease in these costs, we may see these costs increase in the future because we expect there could be more rules coming down regarding dead lines.

So I guess the bottom line is, we've got

all these things going through reserves. Unless you do a thorough depreciation study, ask the right questions, I think it's very difficult to know what the proper depreciation rates are going to be. And it would be my comment the last time we did a thorough depreciation study was 1991. It was done by Stone & Webster. And we haven't done one since. We're looking at doing one.

One of the reasons we haven't had one completed is that right now it's tough to get consultants. Everyone is busy with 143 and everything else. We also ran into a problem in that Stone & Webster, who previously did our study, they had some financial problems, some people turnover and they moved. They have lost all our records that we had. So it's not just a matter of updating our records going forward. We're going to have to go back and provide and reprovide all our records from back as early as we can -- you know,. I think we have most of our records, but we're going to have to redo it. So it's going to take a little longer than our prior study. But we're hopeful to have it done by the end of the year.

It would be my recommendation since the last thorough study done was 1991, that that should

be used for setting rates in this case, and that 143, as recommended by Mr. Fox's opening remarks, is that we should move this to another day. It shouldn't be handled in this case.

MR. HOBERG: Thank you, Mr. Keller.

Any additional questions of Mr. Keller?

MR. PEARCE: I have no questions. I just will offer the exhibit.

Q. (MR. PEARCE CONTINUING) Craig, did you prepare your prefiled rebuttal testimony?

A. Yes, I did.

MR. PEARCE: And that's marked as Exhibit 23. I'll offer that at this time.

MR. HOBERG: Exhibit 23-53 --

MR. BINEK: No objection.

MR. HOBERG: -- is admitted. Okay.

Mr. Pearce, did you have some questions of Mr. Keller?

MR. PEARCE: I don't.

MR. HOBERG: I'm sorry. I looked at Mr. Binek and said Mr. Pearce. Mr. Binek.

MR. BINEK: I was about to start asking questions.

COMMISSIONER REINBOLD: These guys are not interchangeable.

MR. HOBERG: Mr. Binek, please.

MR. BINEK: Thank you. I'll take his money, though.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Keller, if there's a bankruptcy of MDU Resources that is a result of activities of either unregulated or regulated entities of Montana-Dakota or MDU Resources, isn't a bankruptcy court going to look at all assets of MDU Resources to satisfy creditors' claims?

A. There's -- it depends on what level. You're saying it's at the parent company level?

Q. Right.

A. At the parent company level, they can look at the assets of that, yes. However, I should point out what we're protecting, is we're protecting our regulated customers from the nonregulated business and that's what you're -- you know.

Q. I realize that, but the protection only goes so far.

A. Well, we're trying to do everything we can do to strengthen that as best we can.

Q. Now, I'd like to have you turn to page 3 of your rebuttal testimony. And specifically at line

16. Are you there?

A. Yep.

Q. Okay. At line 16 you object to Mr. King's use of a historical year-end 2001 capital structure and argue instead for your forecasted 2003 capital structure. What capital structure did the company use in its rate-of-return testimony in the electric case earlier this year? That's PU-399-01-186.

A. I'm going to defer that to Rita.

Q. Okay. Now, please turn to page 5 of your rebuttal testimony. At line 14 -- beginning at line 14 you state that FAS 143 does not provide levelized depreciation rates, but instead pushes higher costs toward the retirement date of an asset due to the discounting method used.

Is it your contention that the current method of recovering negative salary produces a levelized effect on ratepayers over the life of an asset?

A. My comment when I made that comment, and I think Mr. Jeter addressed that quite well, is that because of the discounting that is associated with 143, it tends to push numbers, push a cost toward the back end because of the way the discounting interest accretion is done and that's what I'm

addressing here. If you're going to ask specifics on 143, I guess I would defer to Mr. Jeter because I think he's the expert in that area.

Q. Okay. Let's move forward a little bit and see where we end up here.

A. Okay.

Q. If we assume that an asset has a removal cost of, say, 50 percent of its original cost, that cost is recovered ratably; that is, evenly over the life of the asset, correct?

A. That's the theory behind it, yes, the goal.

Q. And that's what you mean by levelized?

A. When I mean levelized -- when I use my primary term levelized, is that we have rates that are consistent and that the rates aren't changing from year to year. That's what I refer to as levelized. And my concern was under FAS 143 because of accretion, if you follow that to the rule, you're not going to get -- you know, you'll see it pinned on the asset as the asset ages. Because of interest expense, accretion is going to change every year. You will not get levelized rates. They will constantly fluctuate. And when I refer to levelized, that's what I'm referring to.

Q. Haven't you forgotten the rate base effect?

When an asset is new, it has very little negative salvage, the removal costs accrue and ratepayers pay a return in income tax on the whole investment; isn't that correct?

A. Can you restate that for me, please?

Q. When the asset is new, it has very little negative salvage cost that's accrued; is that correct?

A. If you're accruing it ratably, I would assume so, yes.

Q. And the ratepayers pay a return in income tax on the whole investment; isn't that correct?

A. On the whole investment net of depreciation reserve?

Q. Yes.

A. Yes.

Q. Only later when the accumulated reserve is built up to a reasonably high level do ratepayers get the benefit of the rate-based deduction represented by accruals of removal cost; isn't that also correct?

A. I would disagree with that. They get the benefit the whole time because -- they get a return basically based on the unrecovered book value, so, you know, that rate base deduction, as you collect

more depreciation will grow, but they're getting the benefit over the whole time.

Q. But it grows; isn't that correct?

A. On that particular asset, yes.

Q. Isn't it true then that the existing system is front-loaded in contrast to the back-loaded recognition of costs under the FAS 143 procedure?

A. I would disagree with that as well. I think the idea of 143 is to accrue it ratably over the life so that you have a proper matching of use with cost. So, you know, I think when we say -- I think 143 tries to separate the interest component from the other pieces. What they're trying to do, I think, is to add some more complexity there, but I think the intent is to accrue it ratably.

Q. Because of system growth and because of inflation isn't the company always adding more plant expressed in dollars than it is removing old plant? Maybe -- they're adding more new plant than they're removing old plant?

A. Are we talking dollars? Are we talking feet? What are we talking?

Q. Dollars.

A. I believe that we've been holding -- you know, they've been fairly constant over the last few

years, that our overall utilities additions and reserve has been fairly constant, but, you know, I think in some years it's less, some years it's more.

Q. Has there ever been a year when the company's gross plant declined?

A. Gross plant declined? The gross plant?

Q. Right.

A. I couldn't answer that question.

Q. Now, please turn to page 6 of your rebuttal testimony, line 2.

A. Excuse me?

Q. Page 6, line 2. There you say that you consider this plant to have an indefinite life. What do you mean by indefinite life?

A. When you say plant, we're talking about the system. We have an obligation to serve the customer. And so as long as we have that obligation to serve the customer, you know, we think that we're going to have to maintain the replacements whenever necessary to keep the system operating.

Q. Okay. Can you identify the specific plant accounts that you consider to have an indefinite life?

A. Well, I mean, I think what -- the responsibility is to -- we have the obligation to

provide service, reliable service indefinitely, so I would guess that the accounts and the assets we have are necessary to do that, so my question would be which of them -- you know, unless technology makes something obsolete, I'm guessing we need all those accounts. We're going to have to replace all of those assets to continue that service.

Q. Did you hear me asking questions about the building that was sold?

A. Yes, I did.

Q. And I think that I was referred to you.

A. Okay.

Q. First of all, what building is this that was sold?

A. It was the Schuchart building.

Q. Okay. Now, where is that building located?

A. It's located on Divide, the old Gold Seal building.

Q. That's the gold building up here?

A. Yeah.

Q. When was that building sold? I'm going to go through the same questions.

A. I think -- I believe it was transferred, sold to an affiliate, I believe it was July 1, 2001.

Q. What was the original cost of that

building?

A. I don't have the information. It was several million dollars. I don't know the exact number.

Q. Okay. But you can provide that information?

A. We can provide it, yes.

Q. Okay.

A. Now, are we talking about the original cost? There was an original cost plus improvements that were made to the building.

Q. Right. And I think we're going to want all of that.

MR. HOBERG: You want a late-filed exhibit, Mr. Binek?

MR. BINEK: Yes, please.

MR. HOBERG: That would be 3, Mr. Pearce.

MR. PEARCE: That's fine.

Q. (MR. BINEK CONTINUING) And when was the building purchased, do you know that?

A. It was purchased in the early -- early to mid 1990s. I'm not certain of the date.

Q. Okay. Once again, I would ask that all of this information be included in a late-filed exhibit, but I'll go through it anyway --

A. Sure.

Q. -- if you can provide some information. Why was the building sold --

A. Initially, when the building --

Q. -- or transferred? I think you used the term transferred.

A. Transferred, sold. Initially, when it was purchased, we were running out of space in our current building so we acquired this building. As the company grew, the share of activities associated with the resources group became less and it was decided that it should be moved outside of the utility since it's -- you know, I think the utility now is quite a bit less than half of the operations over there, so it was decided to move to a different company.

Q. Okay. And the sales price, do you know what the sales price was?

A. The sales price was set at the net book, unrecovered book value of the asset, and I don't know the number. It seems to me it was in that four- to five-million-dollar range. I don't know. It's here someplace.

Q. And what was the entity that it was sold to?

A. It was a subsidiary of Centennial. I believe the subsidiary's name is Future Source. I can't give you the exact legal name. Future Source.

Q. Once again, that will be included, I assume. And I asked Mr. Jeter, I believe it was, to provide all of the journal entries relating to the sale.

A. Okay.

Q. Was there an appraisal done prior to the sale or transfer of this building?

A. I don't believe so, but I can't answer that for sure, but I do not believe there was an appraisal done.

Q. Do you know what the tax appraisal of the building was at the time of the sale?

A. No.

Q. Can you provide that information also?

A. Yes, we can.

MR. BINEK: Okay. And I'm asking that all of that information be included in a late-filed exhibit.

MR. HOBERG: Late-Filed Exhibit 3.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Reinbold, did you have any questions?

COMMISSIONER REINBOLD: I think so. Probably a statement, too. Everybody is making statements.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. You know, when I was a kid out at Hebron, 50 miles west of here, MDU was a pickup and two guys with patches on their arms and natural gas and electric service and that was MDU. And everybody accused them of long coffee breaks. And that was kind of a joke in the community, you know. But that wasn't -- I don't think it was the case. They're very efficient. And the point I want to make now is that from that point to now we've really come a long way. And when I say that, I understand MDU Resources Group, Inc., has purchased a number of businesses.

Can you kind of rattle off a list of the businesses that the big MDU Resources now has?

A. Well, I think probably best would be to talk about the lines of business we have. We have, of course, our electric/gas utility operations. We have WBI, which has a transmission and gas storage gathering, as well as an oil and gas exploration, and they also do some -- they have some companies in

what I call innovative technology, where they're looking at, I would say, breaking technology that's applicable probably to some of the things we're in. We also have Knife River Corporation, which invests in aggregate mining, as well as building, road construction and stuff, activities.

We have USI, which is Utility Services, Inc., which is involved in the building and developing of a -- I should say replacing, I would say, utility, electric, gas, overhead, underground lines. They work with the generation side. They do work in telecommunications, as well as inside electrical work, as well as traffic light signaling. And then we have Centennial Power, which is involved in the investment in IPP, looking at doing investments in IPP. And we also have our foreign operations that are currently in Brazil that have made investments in, I think it's 200 megawatts of a gas turbine and they're also looking at some other projects in South America.

Q. You've come a long way?

A. Yeah.

COMMISSIONER REINBOLD: That's all the questions I have.

MR. HOBERG: Thank you, Commissioner

Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. In Mr. Jeter's testimony he had said that Montana-Dakota has retained AUS Consulting to complete another depreciation study by December 31, 2002. Are you anticipating that the study will be done by December 31, 2002?

A. Well, we're very hopeful it will be done. As I said, you know, one of the issues and problems we ran into is that we have to provide all our historical records because of the fact that, you know, they inadvertently were lost, but we're hopeful we'll have that completed in that time frame, yes.

Q. That was one thing I was wondering about. With the 1991 study, if the Commission wanted to go in and take a look at that and you're recommending the Commission use the 1991 study, is there any backup data that's available to the Commission at this time other than the few summary charts?

A. I couldn't answer that without talking to our plant people or Stone & Webster and find out what exactly -- you know, what records they do have left from that, you know, that they were able to

locate versus what they don't, but I'm not sure how much information would be available.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, any questions of Mr. Keller?

COMMISSIONER CLARK: I do have a few.

EXAMINATION

BY COMMISSIONER CLARK:

Q. Getting back to this building, if through the tax appraisal that MDU is going to be submitting, and I understand there wasn't, doesn't sound like, a fair market appraisal done, but if the tax appraisal comes back in the market that the assessors here were setting the value of that, if that ends up being far in excess of the net book value, would it be fair to ratepayers to somehow give them some sort of realization of the difference between the two that, in fact, this asset that had been in the rate base that the ratepayers have been paying for was then transferred to another affiliate within the MDU group, but at far less than the market value of that?

Would it be fair to somehow credit, maybe through an offset of that credit that was originally

given, so that the ratepayers see some realization of that?

A. You know, I would comment that that may be fair for the portion that was allocated to the utility business. A couple comments I'd like to make. One, is that while we didn't do a fair market value, we believe that the book value was very close to the fair market value. So we don't believe, you know -- if we thought there was a big discrepancy in the values, we would have went through and did a fair market value of that, but we don't think there was a big difference between fair market value and net. I'm not sure what the tax value is. I'm not sure if that is a locally assessed or centrally assessed asset. If it's locally assessed, we would have the tax value. If it's centrally assessed, I don't believe it would have a value just for that stand-alone business.

Q. What would be the basis of saying that you think it's pretty close to what the fair market value was, the net book?

A. Well, because we haven't had it that long and we made some pretty substantial investments in there, so we're pretty comfortable that the fair market value -- the fair market value would not have

been much higher than the book value was.

Q. Getting back to the depreciation study that is ongoing, kind of lead me through the -- why was the decision made to have a depreciation study at this time? Was it for the rate case?

A. I'm going -- I'm going to defer that to Rita, but I believe one of the things is, one, it's been a while since we had one, but, secondly, with the cases coming up, we wanted to take a look at it. You know, we look at our plant all the time. We don't think -- you know, one of the comments made, we don't think the makeup of our plant has changed a lot since our last study, but, you know, we thought it may be appropriate to do one. I think it was recommended that we do one for these cases, but Rita could probably answer that better than I can.

Q. When it was originally contracted to be done, was it contracted to be done by the time that this rate case was to be taken up by this Commission?

A. We -- right now, I don't think there's as many consultants in the business doing depreciation studies. You know, the number of consultants -- there seems to be a lot fewer than there have been in the past. We had a very difficult time getting a

depreciation consultant. It was tough to get them. You know, they're quite busy right now. It was difficult to get one. The individual we hired did a depreciation study, just completed one for Great Plains, and we asked him to start on this one as soon as he could and he said he would do his best effort to get it done by the end of this year.

Q. I guess I'm a little confused by that, because I know in the RFP that we put out here at the Commission, I think one of the things that was originally in that was a depreciation study and at some point we decided to peel that off and that I guess MDU would be handling it, but -- and maybe Mike will be able to speak to this when we get to Mr. Diller's questions, but it seemed to me that we had at least five that said that they could get it done by the time that we needed to get it done.

You're saying MDU didn't find anybody out there who could get it done in time?

A. We looked for consultants that had been used by our peers that we knew were very reputable and very good and, you know, we kind of basically looked at -- you know, the people we looked at were the ones we wanted to use. They're very busy right now and timingwise it takes a period of time to do

this and it takes a period of time to gather all these records that we have to go back and recreate, so, you know, we just had difficulty getting a commitment to get it done in a time frame that -- in time to have -- you know, time to have -- prior to the case being filed or this date.

Q. Well, the depreciation case that you have, the study that you have being done, is it going to be ready for the rate cases in the other states within your jurisdiction; South Dakota, Montana, Wyoming, the ones we've heard about that will be --

A. Again, I'm going to have Rita -- he's going to do the study for Montana-Dakota gas operations and would include all our jurisdictions. Timingwise, if that's going to fit with our schedule, Rita could probably answer that.

Q. Okay. Do you know how much -- how much did this particular study cost that you're doing? I know we heard before they're fairly expensive.

A. I'd have to get you that information.

Q. Has MDU received any preliminary information yet on that depreciation study, or is that just all delivered at once?

A. We haven't received any preliminary numbers, no. We're in the process now of providing

information so the consultant can do his work.
MR. HOBERG: Commissioner Clark, did you want a late-filed exhibit on that question?
COMMISSIONER CLARK: I'm sorry. Which question?
MR. HOBERG: The one about how much it costs.
COMMISSIONER CLARK: Yeah, that would be good, if you can provide it.
MR. HOBERG: Late-Filed 4, Mr. Pearce.
COMMISSIONER CLARK: That's all the questions I have. Thank you.
MR. HOBERG: Thank you, Commissioner Clark. Mr. Diller, please.
MR. DILLER: Just a couple.

EXAMINATION

BY MR. DILLER:

Q. Mr. Keller, do you have any knowledge of any agreements that the staff reached verbally with the company as to who was going to do the depreciation study? Do you have any knowledge of that?

A. I don't have any knowledge of that, no.

Q. Okay. I'd also like to add on to Commissioner Clark's late-filed exhibit, if it's all

right, the cost associated with supporting this 11-year-old depreciation study in this proceeding. Since it's going to be virtually obsolete in three or four weeks or a couple of months, whatever it is, I think that would be some information that the Commission might be interested in.

A. Could you rephrase that? Make sure we get what you're looking for.

Q. I just want to know what -- I want to know the total cost to the company to support the 11-year-old depreciation study in this proceeding. Had the depreciation study been done before this proceeding, we wouldn't have spent all this time and money talking about an old study that's not going to be worth anything in a couple of months. So I'd like to know what the total cost to MDU is to support.

A. Well, you know, to say it's not worth anything I think is kind of -- it's a study, but it was a thorough study that was performed and, you know --

Q. Did I hear you say -- I couldn't really hear. You said it real quickly. You said it wasn't done in time because you lost some information?

A. I said one of the reasons we can't get it

done as quickly as we'd like was because we didn't lose some information. Stone & Webster, who performed the last study, lost a lot of the data.

Q. So then if staff had hired a consultant then to do the depreciation study, since we had offers to do that in time for this proceeding, would we have had the same problem? Would we have --

A. It would have been difficult to give you the information. Again, Mr. Jeter may be able to better address this than I can, but I believe to do a thorough, detailed study, I think there's a lot of historical information you're using and, you know, I think there would have been -- to do a complete study, which we are expecting done, I think would have been -- you know, may have been difficult for your consultant to do in time.

Q. Do you understand the question? I'm asking for the cost of --

A. Yep.

MR. DILLER: Okay. I think that's all the questions.

MR. HOBERG: Thank you, Mr. Diller. Any further questions then of Mr. Keller? Mr. Pearce, any?

MR. PEARCE: No.

MR. HOBERG: Mr. Binek, please.
MR. BINEK: Just a couple other questions regarding this depreciation study.

RECROSS-EXAMINATION

BY MR. BINEK:

Q. When did MDU retain a consultant to do the depreciation study?

A. I believe we started looking for one about maybe April and we had -- I think he committed to us, I think, maybe in May. I'm not sure of the dates. And we asked him to complete the Great Plains study and then begin work and complete the Montana-Dakota gas study.

Q. Okay. Included with the late-filed exhibit 4, I would like to ask that any correspondence relating to the contract with -- is it AUS?

A. Yeah.

Q. -- concerning the contract and the contract itself be included in that exhibit.

MR. HOBERG: Mr. Pearce, can you do that?

MR. PEARCE: Well, I assume that's possible, barring some kind of a confidentiality provision that that consultant may have. I don't suppose there is, but I don't know of that, so with that possible proviso.

MR. HOBERG: Anything further, Mr. Binek?
MR. BINEK: No.
MR. HOBERG: Any further questions of Mr. Keller? Thank you, Mr. Keller.
MR. PEARCE: Can we take a couple minutes? We have some exhibits to mark for Dr. Gaske.
MR. HOBERG: Yeah. Let's take five minutes.
(Recess was taken.)
(Exhibit 31, 32, 33, 34, 35, and 36 were marked for identification.)
MR. HOBERG: We're back from recess, and you're taking the rebuttal of Dr. Gaske at this time, Mr. Pearce?
MR. PEARCE: Yes.
MR. HOBERG: Dr. Gaske, you testified yesterday. I'll remind you today that you're considered to be under oath still.
THE WITNESS: I understand.
MR. HOBERG: Mr. Pearce, please.

J. STEPHEN GASKE,

having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Dr. Gaske, you've prepared prefiled rebuttal testimony in this case, have you not?

A. Yes, I have.

Q. Rather than go through all the testimony, I'm simply going to ask you to summarize that testimony, if you will, and add any additional rebuttal points that you feel are appropriate after the staff's direct case.

A. I will try to go through and summarize my testimony, but I won't read the whole thing. But during the course of the summary I would like to direct the attorneys and the Commissioners to various points in the record, because in the course of summarizing this, I hope to lead you through the facts that have been introduced into the record so that, hopefully, you'll be able to follow along why I'm saying what I am and what the basis of the testimony is.

As a broad general overview there are really four big issues with regard to rate of return. One is the question of the flotation cost adjustment. Another is the comparable companies that we use in our DCF analyses. One is the growth

rate that we adopt, and the last is our assessment of risk. With regard to those four things, I advocate a flotation cost adjustment, which I'll talk about in a few minutes.

There's not a big difference between us with regard to the comparable companies. But there are some differences and there's some key factors that you need to understand. There are large differences between us with regard to the growth rate, and I believe very strongly that my growth rate analysis is based on relatively objective, publicly available information. In contrast Mr. King's is really based on a fairly subjective analysis that on its face appears to be fairly biased.

With regard to risk assessment I have two different opinions, depending on which proxy group you use. If you were to adopt the Moody's gas distribution companies as the appropriate proxy group, I believe that Montana-Dakota is slightly above average in terms of their risk. They're slightly riskier than the average company. If you were to adopt the companies that derive more than 75 percent of their revenues from gas distribution operations, then I believe Montana-Dakota is average

relative to that group.

So having said that, I want to walk through and summarize the rebuttal testimony. With regard to the flotation cost issue, it's very important, I think, to understand why you should be allowing a flotation cost adjustment. The standard that's used to evaluate whether a cost of capital or rather allowed rate of return is sufficient is often referred to as a capital attraction standard. That standard requires a rate of return that is sufficient to enable the company to attract capital on reasonable terms. Now, whether the company actually is going out and raising capital, whether it's growing, whether it needs new capital or whether it's built a system that is not growing at all, it still needs to have an adequate rate of return. And so the standard that was established to set that rate of return was this capital attraction standard. There also is a comparable earnings standard, but when we go to using a DCF analysis, we're really looking at a capital attraction standard.

When you set a rate of return based on DCF analysis, in theory you are finding the cost of capital that makes the investors indifferent as to

whether they invest in this plant or in this company and put utility assets in the ground or whether they put their money in U.S. Treasury bonds or CDs or anything else. In other words, it's exactly the amount of money they need to be compensated for the additional risk.

In theory that means that when they invest $1 in utility assets, the value of that investment will be $1. That will be the market value after it's in the ground, if everything goes well. If they do invest $1, though, and they have to raise equity capital to invest $1 in utility assets, they have to essentially raise more than that. They have to go out into the market and raise perhaps $1.05. The five cents goes to the investment bankers and then they have $1 investment in utility assets.

Consequently, the rate of return needs to be adjusted to reflect the cost of flotation. It doesn't mean the company is going to go out and issue common stock. It doesn't mean that it's done so recently. It means that in order to be in a position to attract capital, in my opinion, to meet the capital attraction standard, it has to have a rate of return so that it can go out and issue that common stock without diluting the existing

investors' investment. I put together a numerical example of this concept that I'd like to hand out as an exhibit. It a little bit complicated, and I won't spend too much time on it, primarily because I think you'll fall asleep if I do.

MR. HOBERG: Is this 31?

MR. PEARCE: Yes.

THE WITNESS: Have you handed them out to everyone?

COMMISSIONER REINBOLD: What number is that?

MR. PEARCE: 31.

THE WITNESS: The general assumptions here are that the company has existing equity of $100, book value of $100, and it has a rate of return that is exactly equal to the investor requirement as determined by a DCF analysis. Under those circumstances, the market value should be $100. The number of shares outstanding is 100, so that the existing investors will have a book value of $1 per share and they have a market value of $1 per share. And I've put $1 into plant and that's what it's worth in the market. If they require a rate of return of 15 percent, they would get $15 of return. And that's what this shows across the first line of

numbers there.

If the public utility then goes out and issues new common stock because it needs to build new plant, and it issues $100 in new common stock, under the example here that I have, I've assumed that the investment bankers take 10 percent of that. They take $10. So the company issues $100 in common stock. They raise $100. $90 of that gets invested in a utility plant that's allowed to earn a rate of return. If they earn exactly the 15 percent required, the utility -- the new utility plant will have a book value of $90 that will go into the rate base. The market value will also go up by $90 because they're earning exactly their allowed rate of return. The number of shares outstanding has now doubled. They issued 100 shares all at $1 apiece. But they got net proceeds of $90 so they have 200 shares outstanding now and the new book value is 95 cents per share. And the new market value, if they are earning 15 percent, is also 95 cents per share.

The impact on the existing shareholders is that they were sitting there with stock that was worth $1 and now their stock is worth 95 cents. The reason being is that the company went out and built a utility plant and raised new common equity to

build that plant and was left with only $90 that they could put in their rate base, even though they had to issue $100 worth of common stock. The effect was to dilute the existing investors' return and the value of their stock. If they earn a 15 percent rate of return, the new larger company would have -- in the last column it shows that the new larger company would make $28.50 a year. They get a 15 percent return on the plant that's in the rate base, but they get a zero percent return on the flotation costs that they incurred.

And just in this example, instead of getting a 15 percent rate of return on all of the dollars that were spent, they get a 14.25 percent rate of return. They don't get the 15 percent that the DCF analysis told you that they required. They were not in a position to issue new common equity on reasonable terms without diluting the value of the stockholders' investment.

The second example I have here is a flotation cost adjustment where you increase the allowed rate of return by 10 percent. You multiply 1.1 times the 15 percent that investors require. That comes out with an allowed rate of return of 16.5 percent, which is more than what investors

require, but the goal here is to increase the market value above the book value by 10 percent. Here, if you look at the first line of the second example, you have a book -- starting book value of $100. Because you've applied a flotation cost adjustment, the market value is actually $110. So the market value is actually worth more than the book value. And with 100 shares you have $1 in book value and $1.10 in market value per share.

Now, when the utility goes out and says we need to build new plant, we need to raise common equity to invest in new plant, they sell 100 shares of stock for $1.10 because that's the market value of the stock. They raise proceeds of $110. $10 goes to the flotation costs. That ends up going to the investment bankers. And they're left with $100 that they can invest in utility plant. So by issuing the new common stock, they can add to their new plant by an amount of $100. That new equity if it has an allowed rate of return -- or I'm sorry. They add to their existing plant an amount of $100. If they get a 16.5 percent rate of return on that, it should be worth $110.

In total now, the company has 200 shares outstanding. They have $200 in their rate base

that's earning a return, and they have a market value of $220. The market value is higher than the book value in this case because you've made a flotation cost adjustment. The price per share and the book value per share is $1. $1 for the book value and $1.10 for the market value. You can see that those numbers are the same after the issuance as before the issuance.

The existing shareholders don't lose anything by virtue of the fact that the company has issued common stock. So the company is able to issue the common stock on reasonable terms without diluting the value of these existing shareholders' investments. That -- I don't think I'll walk you through the rest of it because it's a similar example down below.

The last example is just a much larger stock issuance, but the result is the same. You start with a book value of $1. You have a market value of $1.10. You're able to issue common stock and still -- the existing shareholders are still in the same position they were before.

Now, the question is, if the company has not been issuing common stock in recent years, why do you allow this? It's not because they need to be

compensated precisely for what they have just issued in the last year. It's not because they need to be compensated for what they know; in fact, right now they're going to earn next year. It's because the company needs to be in a position to do this at all times. It's a little bit like insurance. I didn't have a car accident last year, so why do I need insurance this year? I didn't have to raise capital last year. Why do I have to have a flotation cost adjustment so I'll be in a position to do so this year? That in essence is what the issue is about.

I mentioned in my rebuttal testimony that a number of other economists advocate exactly the same kind of adjustment. It's not an unusual thing. It is supported by the economic literature. Mr. King has indicated that the company's experience in the recent past has been that flotation costs have been 0.1 percent of the capital rates. That's actually very misleading, because, in fact, that's not what the flotation costs have been on the capital that has been raised.

Let me give you the biggest area where that becomes misleading. Mr. King has noticed that the company issued about $400 million worth of shares to buy other companies. Well, that's not raising

capital. You don't have big flotation costs to swap shares with someone. It's just a share swap. No cash was raised that could be used to go out and put mains in the ground for the public utility customers. Transactions like that don't have very big flotation costs associated. So you really can't include that in the concept of what does it cost this company if it were to have a need to go out and raise cash for the utility operations. The recent historical experience for the company is shown on page 5 of my rebuttal testimony, at lines 12 to 15.

COMMISSIONER WEFALD: Which page, please?

THE WITNESS: Page 5. In recent years the company has raised $157 million. It incurred flotation costs of 5.2 million and the flotation cost adjustment or the amount of flotation costs was 3.43 percent of the net funds that they raised. So that's been their recent experience. If they had no recent experience whatsoever, they would still need a flotation cost adjustment. If they had raised lots of money recently, they would need one on a forward-looking basis. Because this is much more of a concept similar to the idea of risk where it's a forward-looking thing where you need to be in a position to do so at all times.

The study that I've done that appears in my direct testimony was to look at many gas distribution companies and the costs that they have incurred in the past. And I came up with an average of about 4.85 percent as the average for gas distribution companies in terms of the flotation costs. I recommended in this case an adjustment of 4.75 percent as being on a forward-looking basis what the company might on average expect to incur. Sometimes they might get less than that. Sometimes they might have to pay more. And it's just depending on conditions in the market at the time.

I guess to summarize, there is a need for the flotation cost adjustment. Mr. King's adjustment of 0.1 percent does not reflect what it costs to raise capital, and I'll leave it at that on that issue.

The next issue I want to talk about is the proxy group. I have another exhibit to show you. Essentially --

MR. HOBERG: Are you offering 31?

MR. PEARCE: I'll offer it now.

Q. (MR. PEARCE CONTINUING) Dr. Gaske, did you prepare Exhibit 31?

A. Yes, I did.

MR. PEARCE: I'll offer Exhibit 31.

MR. HOBERG: Mr. Binek, any objection?

MR. BINEK: No.

MR. HOBERG: Exhibit 31 is admitted. Please continue, Dr. Gaske.

THE WITNESS: The next exhibit is Exhibit 32.

MR. HOBERG: I've got that here for the Commissioners.

THE WITNESS: I just noticed that there's one thing that's not correct here and that's in the sources I have bond ratings. And, in fact, there are no bond ratings on this page. I had carried that over from a copy of another exhibit. So --

COMMISSIONER WEFALD: Cross that out?

THE WITNESS: -- you can cross that out. The other source is the percent gas distribution, and with one exception that was taken from Mr. King's testimony. The one exception is Keyspan. And if you'll recall yesterday, an exhibit was introduced that showed it was from the Keyspan 10-K and it showed their percentage of revenues from gas distribution and I was asked about that percentage. I did not calculate it in my head, but I went home last night or back to the hotel and calculated 54.5 percent. So it's at the bottom there.

These are the proxy companies that Mr. King and I have used. They're all put together. We have used two different groups. I've used the Moody's gas distribution group. It's a group that I've used routinely in the past in gas distribution cases. The companies in that group are marked with an X here. It's commonly used as a group of companies that are representative of the gas distribution industry and people look at this group for information in general about the industry.

Each of the companies is included in Value Line as being a gas distribution company. Each of the companies is also included in the CA Turner Reports as being a gas -- or gas distribution or integrated gas company. So they are widely perceived to be gas companies. I believe it's appropriate to use these companies for a DCF analysis. It is something -- as I note in my testimony, Mr. King used the same companies about a year ago before this Commission.

Mr. King has proposed an alternative proxy group. And that's companies that derive at least 75 percent of their revenues from gas distribution companies -- or gas distribution operations. The

percent gas distribution column, as I said before, is taken right out of his testimony. You can see that the companies that meet the standard that he established include all of the companies down to Peoples Energy Corp, which derives 80 percent. So actually all of the companies that really meet the standard derive not just at least 75, but derive more than 80 percent from gas distribution.

Mr. King has proposed to also include WGL Holdings, but in my rebuttal testimony I asked the question since they didn't meet his criteria, you know, why would you include it? So that in essence is -- if you want to look at the companies and the criteria that were used to select them, that compares our two groups and accounts for some -- to a small extent some of the differences between the two of us in our studies.

The next area that I want to talk about is the growth rate differences between the two of us. And to help you in the discussion of this, to help me in the discussion of this, I've prepared another exhibit. I know it's been marked as Exhibit 33. Since I'm leaving 32, is there anything --

Q. (MR. PEARCE CONTINUING) Are you finished talking about 32?

A. Yes.
Q. And did you prepare Exhibit 32?
A. Yes, I did.
MR. PEARCE: I'll offer Exhibit 32.
MR. BINEK: No objection.
MR. HOBERG: Exhibit 32 is admitted.
THE WITNESS: The data on Exhibit 33 attempts to do an apples-to-apples comparison between Mr. King's study and my study and other alternatives that have been discussed on the record, as well as alternatives that I have included in my rebuttal testimony. The first column of numbers shows the average results from various studies using various growth rates. My -- and I should say that column is what I refer to as the investor return requirement. It does not have a flotation cost adjustment. The cost of capital after flotation cost adjustment is shown in the last column, but for purposes of this discussion and comparison, I'm really going to focus on the first column.

My second stage retention growth method, which was conducted on Moody's gas distribution group, came up with a 12.83 percent rate of return on average. That simply is a weighted average, two-thirds of the weight on the Zacks analyst

estimate and one-third on the book value growth rate -- or, actually, the earnings retention growth rate.

The second one is the basic study. That's identical to what Mr. King refers to as a classic study, where you simply add the Zacks growth rate estimates. The only difference between us really comes about because we have different companies in our proxy groups. The primary one in my study was one that I looked at the results, I made some subjective judgments and came up with an average of 12.63 percent. And you can see where I made my subjective judgment, my average rate of return actually comes in below what either the second stage retention or the basic came in at. And that was very specific to the companies in the Moody's gas distribution group.

The next group, going down the list, is really derived from cross-examination yesterday when I was on the stand. I was asked what would the average results be if Keyspan and Laclede were removed from my groups, and I couldn't calculate the average in my head, but -- exactly. I think I had some ballpark number, but my second stage retention results would have been 11.75, and my basic would

have been 11.51. Now, I believe that it is appropriate to include Keyspan and Laclede in the results, but these are some numbers that you have before you in the record and when you sit down to consider rate of return, you're going to be looking at these numbers and having to weigh them against the others. I really do believe that those two companies should be included in the group and so you can take those numbers for whatever they're worth. I don't put lots of weight on them.

The next set of numbers are numbers that appear in my rebuttal testimony. I would direct your attention to Exhibit JSG-4, which are the exhibits that are attached at the back of my rebuttal testimony.

MR. HOBERG: JSG-4?

THE WITNESS: Yes. Schedule 1 in particular.

COMMISSIONER CLARK: Which page?

THE WITNESS: I'm sorry. Schedule 1, pages 1 and 2.

Here what I've done is to simply take the companies that meet Mr. King's criteria. They derive at least 75 percent of their revenues from gas distribution based on his numbers. It includes

all of his companies, except Washington Gas Light or WGL. I've used his Zacks numbers, his stock price, his dividend, and his book value per share with the growth rate. The average Zacks growth rate for these companies is 6.38 percent and the average of Mr. King's estimates of the book value growth rate is 7.14 percent. I've taken a weighted average of those two, giving two-thirds weight to Zacks and one-third to the book value growth and come up with an overall weighted average growth rate. I've then taken his stock price and dividend data and adjusted the dividend yield for the .625 dividend adjustment factor that has been somewhat notorious in the case.

And so I've done this in an objective way that matches up with my second stage retention growth method of really taking the information from both of these growth rates and combining them. And I come up with an average of 11.8 percent without flotation costs and 12.4 with. So if you do what I think is much closer to a proper analysis of the growth rate, you would come up with at least 11.8 percent for these companies.

The next page is virtually identical. It's all Mr. King's data and just taking a weighted average and I come up with a -- when I weight book

value growth and Zacks equally, 50-50 for both, I come up with 12 percent for these companies. And those are the numbers and that's the approach.

The last group of figures that I want to talk about are from Mr. King's analysis. His first DCF analysis is based on his book value growth rate. And for his companies, which also included WGL Resources, he came up with a 12.18 percent return and that comes from his testimony on page 20. It's table 7 on that page. Now, you can see the 12.18 percent return in table 7. Immediately thereafter on pages 20 and 21, he indicates that he really doesn't think that this is representative of what investors expect, primarily because for the 11 companies in his analysis, Value Line does not project that their earnings are going to go down in the future.

Well, in fact, if these companies had negative growth rates, nobody would be buying them. He also thinks that Value Line is biased because they project that all 11 companies are going to have increased earnings in the future and they're going to maintain or even increase their current rate of return. So he pretty much discounts and rejects this data. The theory is that Value Line is biased.

Yesterday, in cross-examination of Mr. King, sheets from Value Line were introduced. It showed that Value Line indeed does project declining earnings, declining return on equity for companies. They're not biased. When they believe that a company's earnings are going to go down and its rate of return is going to go down, they do project that. The fact that you can look at these 11 companies and say, gee, they're going to grow in the future is not at all surprising. That's what you expect. That's what the Zacks analysts expect. That's what investors would logically expect for those companies. That's what you expect out of most companies. So at this point in time, you can't take that information and say, well, that means they're biased, just because they think the companies are going to grow or maintain their current rates of return. So Mr. King gives very little weight to the book value analysis, but when you really look at his reason for giving little weight to it, it doesn't make any sense.

He has a historical analysis which is based on historical growth rates. That appears on page 22 of his testimony in table 8. Here, his average rate of return is 11.72 percent. Now, when you look at

table 8 fairly closely, you can see that there's some pretty wild swings. There are some companies that in the past, in the very recent past, have had negative growth rates. No one would actually expect that to be the case in the future. And he has Southwest Gas with a positive 37 percent growth rate, and I don't think you can really expect that to happen in the future, either. These are kind of wildly out of line.

My rebuttal testimony discusses the fact that you really can't give much credence at all to these historical results. Certainly, Value Line, when it does its book value projections, book value growth projections, they were aware of this historical data. The Zacks analysts, when they did their projections, they were aware of this data. I'm sure they took it into consideration. So you really don't have a whole lot here on historical growth numbers typically because they were fairly short periods of time in the past to do much with. But, nevertheless, he has these numbers and he does place some weight on them.

His last approach, the classic approach is that -- that appears on page 23. And I'm sorry. The summary of the three-year results appears on

page 23. The actual analysis appears on page 18, table 6. And here you can see that the average rate of return was 11.29 percent. And that's very straightforward. It's just adding the Zacks analysts' growth forecasts.

One of the major places that I think Mr. King's analysis is flawed is in how he's taken this information and used it subjectively. He says that he started with the classic result, 11.29 percent. And from that he then looked at the book value results. They're a whole lot higher. So he considered those and worked those into the calculation, these much higher numbers. He also took the historical results, also quite a bit higher. So after he gets finished including these higher numbers in his results, he comes up with a lower average on its face that just doesn't make a whole lot of sense.

Now, he says that he went company by company and really analyzed each company individually and described why he did what he did, but the fact of the matter is, is that the level of bias is pretty high when you consider that after consideration of much higher numbers, he ends up with a lower number than he started with. That

gives him a 11.23 percent rate of return. You, as Commissioners, will have to decide out of this evidence that's in the record which of these numbers are credible and which ones to place true weight on. And I would say that, in my opinion, the 11.23 number doesn't make any sense whatsoever.

To the extent that you place any weight on the numbers and evidence that he has put in the record, the recalculation that I've done that gives very explicit consideration to both Zacks and the book value growth rate; the two-thirds/one-third or the 50-50 analysis. They come out pretty close to each other; 11.8 percent or 12 percent before flotation costs. Those at least you can trace mathematically. You can debate whether or not the assumptions are correct and actually have some reasonable basis for decisionmaking.

Now, yesterday I talked about the fact that I generally believe that book value is a floor for your long-term growth rate. I think Mr. King agrees with me on that, but then he ends up saying that he really considers book value to be a ceiling because it has the highest number. But if you look at page 19, lines 5 to 13 of his testimony --

COMMISSIONER WEFALD: 15 to 19 of his

testimony?

THE WITNESS: Page 19, lines 5 to 13.

There he says that the book value growth model is less useful for gas utilities than it used to be for two reasons. One, is that these companies are somewhat diversified. They don't just get their income from regulated operations. The other is that he thinks very few utilities are so closely regulated that the only source of growth in earnings is the increase in book value. Now, I agree with both of those statements. They parrot exactly what I said yesterday when I was on the witness stand.

What these two statements say is that these companies have some unregulated operations so book value growth is not necessarily the best indicator of their growth rate because they have ways they can grow even faster than that. So later in his testimony or around this point in his testimony where he says that book value is a ceiling, the reasoning he has in his own testimony suggests, indeed, that it should be a floor, which is what I think. So when you're looking at his testimony and looking at the 12.18 percent book value and the reasons that he gives for rejecting it, I think you'll find that the record shows that they're not

particularly good reasons, that they don't actually fit with the reasoning of his own testimony. That's one reason in addition that I really don't give a whole lot of credibility to that 11.23 percent that he came up with subjectively.

If you look at the ultimate results he comes up with subjectively, which appear on page 24 of his testimony in table 10, he has his 11.23 number there, and these are his kind of subjectively derived numbers. The range of rate of return there is 9.5 percent to 14 percent. If you go back to Exhibit JSG-4, Schedule 1, that's at the back of my rebuttal testimony, and looking at Schedule 1, page 2 of 2, that's the 50-50 weighting. The range of returns on that exhibit is 9.53 to 14.09. In essence, it's virtually identical to the range that he has in his ultimate DCF analysis. But the average is very different. The average for the group is 12 percent. So I would submit they're not enormous differences between us, but somewhere in the course of making some subjective adjustment, he's come out with a very low number that just is not reflected by the record.

I believe that Zacks growth rate and the book value growth rate should both be given at least

some serious consideration, should both be reflected, and that the appropriate growth rate is somewhere between the two, not below either of them. So having said that --

MR. HOBERG: Commissioner Wefald.

COMMISSIONER WEFALD: On Mr. Gaske's -- now we're about page 10 of his 29 pages of testimony. How much longer is he anticipating going, because I do want to make sure that we have a chance to ask questions of the other people who are here and have a chance to hear the other presentations?

THE WITNESS: I think I've gone through the really detailed parts. It won't -- I don't think it will be nearly as long to do the last.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: The next area that's fairly important is the risk assessment. Mr. King believes that the company, Montana-Dakota Utilities, is a relatively low-risk operation. His primary reason for saying that is that Montana-Dakota Utilities is a part of a very large company. Now, yesterday he gave an example of Atlanta Gas Light, who lost a customer and, you know, obviously had some risk there.

The thing about Atlanta Gas Light is that

in my direct testimony I have evidence that compares the size of Atlanta Gas Light to the size of Montana-Dakota's gas distribution operations and that appears on JSG-2, page 1. And it looks like Atlanta Gas Light's assets are 3.3 billion as opposed to Montana-Dakota's gas distribution assets of 183 million. The operation operating income for AGL was 209 million, but Montana-Dakota's gas distribution operating income was $4 million, an enormous difference in size. For AGL, with a large territory, a very large population, that it serves, it can lose major customers and it will hurt AGL. Montana-Dakota, on the other hand, can be hurt much more if large companies, large operations leave its service territory leaving people unemployed, and perhaps stranded facilities behind or other impacts along those lines.

It's interesting, his argument on the small company issue, because one of the reasons he says Montana-Dakota has low risks is that we're only looking at the gas distribution operations. We're looking at them as a stand-alone operation and they're 100 percent gas distribution, whereas these other companies are diversified, at least to some extent, and at that part of his testimony he says,

essentially gas distribution is less risky than a diversified company. However, when he gets to the small company issue, he says, well, actually, these gas distribution operations of Montana-Dakota, they're part of a great big company.

So there's a direct contradiction there in what he's saying. On the one hand, the company is low risk because we'll look at it on a stand-alone basis, 100 percent gas distribution business. On the next hand, it's also low risk because it's part of a larger holding company with other operations so we'll look at it on a consolidated basis for that issue. Two diametrically opposed positions on the risk when analyzing risks in different situations, but both of those positions lead to the same conclusion, low risk, at least in his mind.

Now, one of the things that he talked about yesterday was, for example, competition. All of these companies, including Montana-Dakota, face competition. So it's not a major factor to distinguish them. He talked about Washington Gas Light in particular, and I have another exhibit and I won't spend too much time on it, just to introduce it into the record, but I went on the Washington Gas Light Website because I happen to be a customer of

theirs. I know something about what happens in their service territory and what has happened in the past.

This Exhibit No. 35, which I think was just --

MR. HOBERG: Exhibit 34?

THE WITNESS: I skipped over 34 in the interest of saving time.

MR. PEARCE: While we're paused for a moment, I'd like to offer Exhibit 33, which I didn't do before, the DCF summary.

MR. HOBERG: Okay.

THE WITNESS: In the late '70s and early --

MR. HOBERG: Just a minute, please.

Mr. Binek, any objection to 33?

MR. BINEK: No.

MR. HOBERG: 33 is admitted then. You skipped over 34, Dr. Gaske?

THE WITNESS: Yes, I did.

MR. HOBERG: Are you still offering 34?

THE WITNESS: Yes, I think I'll mention it very quickly at the end.

MR. HOBERG: Okay.

THE WITNESS: In the Washington, D.C. area a lot of new homes were built with electric heat

pumps in the late '70s and early '80s. It was a relatively new type of appliance. The cost of gas at that time was over $4 a decatherm. On an inflation-adjusted basis we're probably talking about $12, $15, and new homes were being built with these heat pumps. The thing about the heat pumps is that they didn't really work very well. My parents have one and they have heavy sweaters that they wear all the time. People figured that out and not a whole lot of heat pumps are being put in place. The price of gas relative to electric heating has come down considerably since then.

On their Website they talk about the fact that they have an active program for conversions. A lot of people who bought houses that had heat pumps in them are converting. In their Website they say that for gas heating, gas heating is preferred 4 to 1 in their service territory. They have about 80 percent of the heating market. They also in the same exhibit say that 9 out of 10 new homes in the metropolitan area are heated with natural gas.

COMMISSIONER WEFALD: What is the relevance of this exhibit?

THE WITNESS: The relevance is that yesterday we were told that, well, the proxy

companies really face a great deal more competition than Montana-Dakota does. Montana-Dakota faces competition, potential competition from propane. This company faces competition from electric heat pumps. And I wanted to place this in context, that, in fact, they're winning 90 percent of the new business. So they do have competition, and I don't dispute that. Montana-Dakota has competition, and I don't dispute that, but it's really a matter of what degree and how much weight do you give that competition in distinguishing between the companies.

MR. HOBERG: Are you offering Exhibit 35 then?

MR. PEARCE: Yes.

MR. HOBERG: Any objection to Exhibit 35, Mr. Binek?

MR. BINEK: No. I think it's kind of what we were trying to establish yesterday.

MR. HOBERG: Okay. 35 is admitted.

THE WITNESS: Okay. The last exhibit that I want to introduce is the bond ratings for the companies in Mr. King's proxy group. Now, Mr. King says that Montana-Dakota has very low risk relative to these companies, but when you look at the bond rating, it's right about at the average or the

median of the group. It's not exceptionally low. What's interesting about this is that, as he and I both discuss, Montana-Dakota has at least for this -- in this filing and for the utility operations they have a higher equity ratio than many of the other companies. I maintain in my rebuttal testimony that, in fact, they have slightly or somewhat above average business risks. So you have financial risks represented by the capital structure and you have business risks also in there.

When you put the two together, the company has about average risks and that's borne out by these bond ratings, which reflect a combination of both business and financial risk. In my direct testimony, as I said earlier, Montana-Dakota's first mortgage bonds have a lower average rating than the Moody's gas distribution group. And my overall assessment of that group indicates to me that they have above-average risk relative to that group, but relative to Mr. King's proxy group, they have essentially average risk and that's supported in part by these bond ratings, that they have a higher equity ratio, but I think they have higher business risk.

One of those risks is the fact that they're

small. In his testimony Mr. King at one point, and I want to direct you there, but he says, for example, Southwest Gas may be actually less risky because it's growing rapidly. Well, in Montana-Dakota's service territory there's little or no growth at all and, in fact, if you look behind what's going on a little bit, they have customer growth of about 1 percent per year, but a lot of that is people moving out of small towns to the larger cities. So you have a situation where they're needing to expand facilities in the city, but they still have costs that they have to recover in the smaller towns that factor declining population. And in the long run that's a problem for the company.

Mr. King indicates that a fast growing company like Southwest Gas has low risk. Well, when you -- I talked about this in my rebuttal testimony. If you look at Montana-Dakota, it's at the other end of the spectrum.

I have some additional things in my rebuttal testimony. I demonstrate that the premiums between Baa bonds and U.S. Treasury bonds are the highest now they have -- or just about the highest they have been in 10 years, other than briefly after

September 11th. The force and weight of that is that Mr. King has some testimony where he takes the rate of return that's been allowed in some past periods and says, well, here's what the treasury bond rates were then and here's what the treasury bond rates are now, but Baa bond rates are much closer in risk to the common stock of a gas distribution company. And the higher the risk, the bigger the premium. And we talked about this at great length yesterday so I'm not going to go any further than that.

But if you really look closely at the question, I believe that this increase in the risk premium required by investors probably indicates that if you use the past allowed rates of return as a benchmark, you probably ought to have even higher rate of return now, but that's just as a benchmark. The real heart and soul of both analyses are the DCF analyses, and, hopefully, I've helped you understand what the difference is between the two -- between the two of us on that issue.

MR. HOBERG: Thank you, Mr. Gaske. Did you want to offer 34 and 36?

MR. PEARCE: 36, I would offer.

Q. (MR. PEARCE CONTINUING) Did you want to

say something about Exhibit 34, Dr. Gaske?

A. Yesterday I was asked various questions about, I believe it was Exhibit 11 that was introduced that showed returns over a long period of time. Exhibit 34 looks at Ibbotson data, and it finds that when you do a statistical analysis of the difference between bond returns and stock returns, you're assured that there's a difference at a level of about 99.93 percent. And that shows up on the last page of it. I won't go into a lot of detail on the statistical techniques and things like that, but that's the correct way to analyze something like that.

I looked at the average difference between the two and I found what you would expect, that the probability that the premiums are higher than average is 50 percent and the probability that they are lower than average is 50 percent. In other words, the historical premiums do represent the best estimate of what kind of premiums have been available over a long run in the market. And the questions yesterday about standard deviation and mean, I believe were really off point for whatever point ultimately is to be made with that data. So I put this in the record to have what I believe is a

more appropriate analysis.

MR. HOBERG: Thank you. So you're offering 34?

MR. PEARCE: I'll offer 34 as well.

MR. HOBERG: Any objection, Mr. Binek?

MR. BINEK: No.

MR. HOBERG: 34 and 36 are admitted. Any further questions then, Mr. Pearce?

MR. PEARCE: Did I formally offer the written testimony, Exhibit 24? I don't show that yet. I'll offer that at this time.

MR. HOBERG: Any objection to the formal written rebuttal testimony of Dr. Gaske?

MR. BINEK: No.

MR. HOBERG: Exhibit 24-54 is admitted. You have no further questions?

MR. PEARCE: No.

MR. HOBERG: Mr. Binek, do you have a number of questions?

MR. BINEK: It might be a good time to take a little bit of a break and we may be able to shorten our questions.

MR. HOBERG: I think all of the witnesses, next witnesses and the questions regarding all the next witnesses maybe you want to look at to see.

I'm assuming we're going to get done at 5:00. If that's the goal, then we're going to have to look at ways to do that. So let's take five minutes right here.

(Recess was taken.)

MR. HOBERG: We are back from recess and completed the direct of the rebuttal of Mr. Gaske. Mr. Binek, do you have any questions on cross-examination?

MR. BINEK: Yes, I do have a few. Been able to eliminate a number.

MR. HOBERG: Good.

CROSS-EXAMINATION

BY MR. BINEK:

Q. First of all, referring to your exhibits, how many of these exhibits could have been introduced with your rebuttal testimony?

A. All of these exhibits were prepared last night or subsequent to the filing of my rebuttal. Except for maybe one, all of them were prepared last night in response to various things that Mr. King had to say yesterday.

Q. Based on the record here, they could have been prepared prior to that?

A. Some of them could have been, but the ones

that could have been really reflect information that was available in the record. Some --

Q. Okay. It doesn't matter that much, anyway.

A. There really wouldn't have been any reason to introduce them until I heard Mr. King's rebuttal or surrebuttal yesterday where he discussed a number of things that were in my rebuttal testimony.

Q. Okay. Your Exhibit 31 assumes a market-to-book ratio of 1; isn't that correct?

A. Yes.

Q. Do any of either yours or Mr. King's comparable companies have a market-to-book ratio of 1 or less?

A. No.

Q. In fact, don't all of these companies have market-to-book ratios higher than 1?

A. The same principle that's shown in there still applies but, yes. Yes, their market-to-book ratios would go down if they were to issue common stock, and so the value of their other assets would go down.

Q. When a company sells new stock at a market value greater than book, what does that do to the book value of the existing stocks?

A. It increases the book value of the stocks.

The book value for original cost of the plant, if it puts it in utility plant, will be equal to the proceeds, and the market value, as I show there, will go down.

Q. Now, going to Exhibit 32, if you round WGL Holdings percentage gas distribution to the nearest percentage point, what do you get?

A. 75 percent.

Q. Okay. Had you included WGL in -- what is it -- pages 1 and 2 of Schedule 1 of JSG-4, what would it have done to the 11.8 percent you show?

A. It would have made it approximately 11.6.

Q. So it would have reduced it?

A. Yes, if you included it.

Q. Where does Mr. King say he places weight on his historical DCF returns? Perhaps if you look at page 22 of his testimony at the bottom.

A. I'm at page 22.

Q. Well, in fact, doesn't he say exactly what you've said about historical results on pages 23 and 24 -- or 22 and 23?

A. He says -- yes, he says that in general.

Q. Okay. Thank you.

A. Well, actually we can handle that on brief, because I can't find the passage right now that

would answer your original question.

Q. Okay. I'd like to have you turn to page 23 of Mr. King's testimony. Are Mr. King's book value growth results always higher than the classic returns?

A. No.

Q. Did Mr. King use book value growth as a ceiling in all cases? We're referring to table 10.

A. In some cases, yes. Some cases, no. Actually, you shouldn't say that. On table 10 it's not really entirely clear where those numbers come from. They are really his subjective decisions, and earlier in his testimony he says why he considers it to be a ceiling.

Q. But the question was, did he use book value growth as a ceiling?

A. Some of those numbers are higher than the book value growth rate for its individual companies, yes.

Q. Do you recall Mr. King testifying as to the number of customers AGL has, and do you know how many they have?

A. Now, it depends on which part of their operation. He said that AGL has 11, but, in fact, obviously Atlanta Gas Light has, I would guess, more

than a million.

Q. You're certain of that? Do you know who it markets to?

A. Now, are you asking how many customers the utility has or how many gas marketing customers they have?

Q. It's one and the same.

A. Actually, that's not true.

Q. Well, how many gas marketing customers does it have?

A. Well, yesterday he said that they had 11, but it's a gas distributor that serves, you know, people all over the Atlanta area.

MR. BINEK: No further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Wefald, do you have any questions?

COMMISSIONER WEFALD: No, I have none.

COMMISSIONER CLARK: I have none. Thank you.

MR. HOBERG: Mr. Diller, no questions? Any additional questions, Mr. Pearce?

MR. PEARCE: No.

MR. HOBERG: Nothing further then of Dr. Gaske. Thank you, Dr. Gaske. Next witness, Mr. Pearce.

MR. PEARCE: Call Rita Mulkern.

MR. HOBERG: Ms. Mulkern, you, too, testified yesterday so I just need to remind you that you are still under oath.

THE WITNESS: Yes.

RITA A. MULKERN,

having been previously duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Ms. Mulkern, you have prepared and had prefiled in this case written rebuttal testimony, have you not?

A. Yes, I have.

Q. Is that Exhibit 25? You don't have it there. It's been marked as Exhibit 25.

MR. PEARCE: I will offer that at this time.

Q. (MR. PEARCE CONTINUING) And ask Ms. Mulkern if she could please summarize her testimony.

MR. HOBERG: Any objection to Exhibit 25 -- actually 25-55?

MR. BINEK: No.

MR. HOBERG: No objection. Exhibit 25 is

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admitted.

THE WITNESS: I'll summarize my testimony. What I would like to do is to address certain adjustments proposed by Mr. Majoros; namely, the amortization period for rate case expense, the adjustment to other operating and maintenance expenses for inflation, a statement he made concerning the increase requested, and the price of natural gas. And a statement concerning the reasonableness of the increase in the operation and maintenance expenses.

On page 15, line 18 of his testimony, Mr. Majoros proposes a five-year amortization of rate case expense, rather than the three-year amortization proposed by the company. And the sole rationale he uses for setting a five-year is the time period between rate cases. And I presume he's referring to the fact that it has been eight years since the last rate case.

However, just because it's been eight years since the last rate case does not mean it's going to be another five years before the next rate case. We were able to refrain from filing during that time period because we took action to increase our operating efficiency and reduce costs rather than

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coming in and seeking a rate increase. And Mr. Fox testified yesterday and specifically talked about some of these measures that we took. He also talked about how we'll continue to strive for operating efficiency and cost reduction, but it is not anticipated that we can replicate our past performance and stay out for -- refrain from filing for another five years. We believe that a three-year amortization provides the best time frame for rate case expense.

Alternatively, if the Commission decides that a five-year amortization is appropriate, then the unamortized portion of the balance of that rate case expense should be included as a rate base addition. And the reason for this is that we're spending the money on this rate case. The cash is going out the door today, 2002. With a five-year amortization, the cost will not be fully recovered until the end of 2007 and, therefore, rate base additions will compensate for that time value of not recovering it -- excuse me -- putting in a rate base will give us a return on that component to compensate it for the length of time it takes to recover the cost.

On page 16 of his testimony Mr. Majoros

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proposes to eliminate the inflation amounts from the other operating and maintenance expenses. And he gives his reasons not to allow these because they have not been previously allowed and because he recommends that we not be starting now. Mr. Majoros appears to be missing the point of this adjustment.

In this case we're using a projected 2003 test period. And in projecting out costs for 2002 and 2003, costs were broken down into major categories and these major categories are listed on -- I believe the statements are Exhibit 2, Statement N, page 14. And there we list those items adjusted individually. And those items were labor, benefits, insurance, advertising, and rate case expense. Those adjustments made up 71 percent of the total operating and maintenance expenses for North Dakota gas operations. The remaining 29 percent of costs are real costs incurred by the company and they're not likely to remain flat just because they weren't adjusted individually. This category includes such items as materials, postage, vehicle and work equipment expense, uncollectible accounts and some others. And to adjust these upward, we used a three-year average of the Consumer Price Index.

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The last time this Commission addressed inflation factor in our case was in July of 1991, which was over 11 years ago. Now it is time to recognize that these costs are real costs. They are subject to inflationary pressures, just as the costs we adjusted individually were. For example, we know that postage expense went up July 1, 2002 and overall the increase in our postage expense was about 7 1/2 percent. This postage expense was included in that inflation adjustment, so, if anything, our inflation adjustment could be understated because of that. So the proposed inflation adjustment should be allowed.

And now I'd like to just address a couple statements Mr. Majoros made. First, was on page 2, lines 11 and 12 of his testimony, he made the comment that proposed increases will be superimposed on those already resulting from spikes in the market price of gas. Now, that's a very general, broad statement, and is not supported by the evidence. Montana-Dakota's gas cost has been very stable over the long term, with the exception of the winter of 2000-2001 where there was a large spike in gas costs, not only here in North Dakota, but it was seen nationwide.

Exhibit No. 26 -- or 25 is a graph. Excuse me.

MR. PEARCE: RAM-2, Exhibit 25.

THE WITNESS: 25 is a graph showing the history of gas costs for North Dakota's gas customers, the amount included in their rates through the monthly purchased gas cost adjustment, and this graph is shown for the period of January of 1999 through October of 2002. Now, you can look at the graph and you can see that gas costs, with the exception of that 2000-2001 time period have been very stable and, in fact, they have been slightly lower in 2002 than in previous years. So there have been no spiking gas costs, other than one winter here.

In addition, Mr. Majoros seems to be implying that in reviewing a rate case application, one should take into account the cost of gas when looking at that case. But the cost of gas is not what this case is about. As Mr. Fox stated in his testimony, this case is about the distribution portion of our rates, not the gas costs. Those are separate -- done separately through the purchased gas cost adjustment, which we file with this Commission each month under our rate purchased gas

cost rate tariff 88.

Then on page 5 of his testimony, Mr. Majoros states that a 5.7 percent expense growth rate is not reasonable for the period 2000, 2003. Again, this is a broad, general statement and it's not supported by the evidence. It's unsubstantiated and was made without looking to see why those costs went up. There are certain items that were identified in my direct testimony that increased significantly in 2002 from the 2001 levels. For example, the pension and post-retirement expenses both increased in the 10- to 15-percent range due to the market performance and lower interest rates. Insurance expense also increased significantly in 2002 and that was an event that has been experienced nationwide. There's no evidence to back up his statements and, thus, given the current cost levels, a 5.7 increase is entirely reasonable, it's explainable and it's supported by the evidence.

In fact, if anything, the 2003 levels are too low. Recently, we received the actuarial report for pension and post-retirement costs for 2003. The results show that the amounts we have in our projected 2003 case are significantly understated. And the reason that these pension costs are too low

is because of the returns experienced on the investment in 2001 and 2002. The updated expense for these items will result in an increase in our North Dakota gas operating expenses of $150,000 for pension and $90,000 for post-retirement expenses, above what we included in the case. This is a higher level. It's known. It will be -- start recording on the books effective January 2003 and should be recognized.

I might note that pension expense -- I talked about significant increases. It's a negative expense. It's a credit to expense. In other words, it lowers -- still lowers the cost of service because it is still a negative expense even with the increases we've seen.

In addition, the medical costs for 2003 have also increased from the levels projected. And we're projecting now for 2003 it will be $124,000 over the amount that was filed in our rate case.

That completes my rebuttal testimony.

MR. HOBERG: Any additional questions, Mr. Pearce?

MR. PEARCE: No. I have nothing else.

MR. HOBERG: Mr. Binek, any questions of Ms. Mulkern?

CROSS-EXAMINATION

BY MR. BINEK:

Q. A question that got passed on to you. What capital structure did the company use in its rate-of-return testimony in the electric case earlier this year?

A. I don't recall.

Q. On pages 1 and 2 of your rebuttal testimony -- I guess, let me go back to this other question. Would you accept, subject to check, that the capital structure that was used was based on a year-end 2000?

A. That may be, subject to check. However, this is an entirely different case. The electric --

Q. I realize that. That was just my question, what was used there.

MR. PEARCE: She's simply answering the question. I suggest we let her answer.

MR. HOBERG: Why don't you go ahead.

THE WITNESS: The electric rate case you are referring to is an entirely different situation. That was initiated by a staff complaint. It was not a general rate case filed by the company. I believe if you look at past rate cases filed by the company, going back as far as 1986, we have filed projected

test years and the Commission has used them.
Q. (MR. BINEK CONTINUING) On pages 1 and 2 of your rebuttal testimony, you object to the rate case cost recovery that Mr. Majoros has recommended. I believe you heard the testimony of Mr. Jeter that -- about the company preparing a new depreciation study that will be completed by the end of the year?
A. Yes, I heard that.
Q. If this study shows that MDU's depreciation rates should be changed, would the company be filing a new rate case?
A. I guess at this point I can't answer what we will or won't, whether or not we file a rate case.
Q. Okay. If the company did, this would result in two rate cases in the space of one year, wouldn't it?
A. Well, there are several options. As Mr. Jeter mentioned, one option would be a very limited scope, look purely at the depreciation study, and that would be different than a full-blown rate case like this where we are looking at many different issues.
Q. If MDU had completed the depreciation study in time for this case, we'd only have one case; is

that correct?
A. I guess I really can't answer that.
Q. On page 3 of your testimony you state your disagreement with Mr. Majoros' proposal to allow inflation increase and other expenses. Mr. Majoros says he declined to increase these costs for inflation because such inflation has not previously been allowed. Is he correct?
A. Last time this Commission reviewed it was in 1991 and at that time they did not approve it. However, I stated this is 2002. These rates go into 2003, and it is time to recognize that these costs are real and they do -- are subject to inflationary pressures.
Q. I'd like to have you turn to page 13 of Statement N.
MR. HOBERG: Page 13?
MR. BINEK: Yes.
Q. (MR. BINEK CONTINUING) Do you have that?
A. I have it here.
Q. Okay. Does that page show the principal categories of cost to which you have applied the inflation factor?
A. It shows the cost by function.
Q. What is the largest category of expense

shown on page 13?
A. Largest function is administrative and general expenses.
Q. What's the next largest?
A. Next largest is customer accounts.
Q. Okay. And this category of uncollectible accounts -- or that category would consist primarily of uncollectible accounts, wouldn't it?
A. That would be one of the factors in there. Not the sole factor.
Q. Why would uncollectible accounts increase with inflation?
COMMISSIONER WEFALD: Excuse me. What page are we on?
MR. HOBERG: Page 13 of Statement N.
COMMISSIONER WEFALD: Thank you.
THE WITNESS: Uncollectible accounts are a function of various things. I don't know that I can tie inflation to it specifically or tie it to inflation specifically.
Q. (MR. BINEK CONTINUING) Wouldn't uncollectible accounts be more correlated with the overall size of your revenue?
A. It would be revenue. It would also be the ability of customers to pay. Maybe if, you know,

the economy isn't doing well, customers might have more problems paying their bills. That could be indirectly associated with inflation. There are other factors other than the revenue.
Q. Does page 1 of Statement N show that you predict that overall revenue declined dramatically between 2001 and 2002 and will remain virtually flat between 2002 and 2003?
A. What we do in a rate case is, we tie our revenues and cost of gas together at a certain point in time in order to -- because we are looking, really, at what the distribution margin is. So the revenue number of 67 million -- this is in thousands, 944 for 2002 is not our projection of what actually revenue would be. It's our projection of what volumes will be for 2004 at the revenues at a certain point in time. In this case it was the revenues in effect for March of 2002. So this number is not representative of a calendar-year revenue that we would expect to see.
Q. Okay. And on page 13 of Statement N, is there any recognition that uncollectible accounts will change between 2001, 2002, corresponding with the decline in operating revenues between those two years?

A. We did not tie the uncollectible accounts to the revenue.

Q. At the bottom of page 4 and the top of page 5 you cite a number of items that you expect will increase, including pension and post-retirement expenses and medical costs. Has Mr. Majoros recommended disallowing your quantification of the 2003 amounts for any of those items?

A. Can you repeat the items he mentioned again?

Q. It was pension and post-retirement expenses and medical costs.

A. I believe he was in agreement with those.

Q. Now, I'd like to have you turn to page 2 of your rebuttal testimony, specifically line 4, and please read -- on page 2, line 4, would you read the statement there down to the end of line 10?

MR. HOBERG: It's part of the record. Can we save time by asking a question about it?

MR. BINEK: No. We'd like to have that read because there will be some followup questions.

MR. HOBERG: Does she have to read it out loud?

MR. BINEK: I would prefer that.

MR. HOBERG: Okay. Ms. Mulkern.

THE WITNESS: The part starting with Montana-Dakota?

Q. (MR. BINEK CONTINUING) Yes.

A. Montana-Dakota was able to refrain from filing for a rate increase during that time because it took action to increase efficiency and reduce costs using new technologies where possible, rather than seeking an increase in rates, all addressed by Mr. Fox in his direct testimony. Montana-Dakota will continue to strive for operating efficiencies and cost reductions, but it is not anticipated that it can replicate past performance and refrain from filing for another five years.

Q. Is it a fact that you did not project past efficiencies and cost reductions in your 2003 test year costs?

A. All past efficiencies were included in the 2001 base period and, therefore, were included in our 2002 and 2003 projected test periods.

Q. Where do we find that?

A. Well, these efficiency measures have taken place over time, over a period of years. And what's happened is Mr. Fox mentioned that we're serving more customers per employee and that's taken place over time. Basically, our employees have remained

flat. I think maybe even declining. So what you see in 2001 is the effect of all of that. So that's implicit. In our base period those things are -- had already happened.

Q. Do we see further declines in 2002 and 2003?

A. No. Because, as Mr. Fox mentioned, and I think I mentioned, we will continue to strive, you know, continue to look everywhere we can to be more cost efficient and reduce costs, but we've looked at all those opportunities. Right now, while we'll continue to look, our option is to file for a rate increase, which is why we are here.

Q. Now, turning to page 3 and lines 7 to 9, is it true that the Commission should not rely on its 11-year-old decisions?

A. I think what I'm saying there is that 11 years ago was the last time they looked at it and it's time to take a look at it again because things have changed over 11 years. I think our point is that these costs are real costs. This isn't a game we're playing with these costs. They exist, and they are subject to inflationary pressures. So we do believe the Commission should look at it again and realize it is time to acknowledge that and

include an inflation adjustment in our cost of services.

Q. Should the Commission rely on the Company's study and data that are 11 years old?

A. It depends what you're looking at. As regards the inflation adjustment, I would say no, because I can't make a blanket statement that any time period is exactly the same for everything.

MR. BINEK: No further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Wefald, any questions of Ms. Mulkern?

COMMISSIONER WEFALD: Yes.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. What if the Commission were to pick a different number than 2.81 percent, higher or lower, how would the company react to that?

A. I think we would want to see some recognition of inflationary pressures, and if the Commission would choose a different realistic number, we would accept that.

Q. How would you define "realistic number"?

A. Well, I guess we defined it as a three-year average of the inflation adjustment. If the Commission might pick a slightly different period, a

two-year instead of a three-year average or some other measure that -- you know, that would acknowledge it, we would be content with that.

Q. I suppose you can't speculate on what the Commission's thoughts were in not giving an inflation adjustment, but I can perhaps speculate that they wanted to give an incentive to the company to practice savings and to find ways to have savings in those costs while moving forward with their business.

If the Commission chose to give a less than 2.81 percent with that same idea of giving incentive to the company to try to achieve savings in those areas, what would you think of that?

A. Well, I think the company -- we've looked for efficiencies. Our incentive is to -- one of our incentives is to not come in and file for a rate increase, so we are constantly looking for efficiencies so as not to let our costs go up to our customers. If the Commission -- you know, as you said, I can't speculate on why the Commission in 1991, precisely why they did not accept it, but I think we already have the incentive to reduce our costs right now.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, any questions?

COMMISSIONER CLARK: I do have just a few.

EXAMINATION

BY COMMISSIONER CLARK:

Q. Some of them are related again to that depreciation study. I know Mr. Keller deferred a couple questions to you. And the reason I keep coming back to this is because I do have some significant concerns in that this is a rate case being brought by MDU and this has become a huge portion of the rate case. But it's like we're arguing about something that could be moot in just a very short amount of time. And I want to point out the scenarios that could happen here.

But are you familiar with when the contract was signed and when this depreciation study was supposed to be done? Is it a date that was originally supposed to be done for this rate case, or was it kind of always anticipated that it would be done shortly after when you entered into the contract with the consulting firm?

A. First of all, I'll say I'm generally aware of the time frame for this. And, initially -- and I think Mr. Keller explained it very well. It was

difficult to find a consultant. We did hire a consultant and that person had to complete a depreciation study for Great Plains before they could start working on Montana-Dakota's study and that took more time than anticipated.

Our intent was to have a depreciation study, I believe, around October 1st. Because of various factors, we weren't able to have one by October 1st.

Q. Well, if it were to be done by October 1st, that wouldn't leave a whole lot of time for the staff depreciation expert to delve into it, would it?

A. No. I'm just kind of referring to the general time frame of this depreciation study.

Q. When, about, did you learn that it wouldn't be done on the October 1st time frame?

A. I guess I really can't recall when I heard. I said I'm generally aware, but I wasn't specifically involved in the contract.

Q. Are you aware of the other pending cases that you have in your other jurisdictions, will that study be able to be used in those jurisdictions?

A. We have filed so far two other rate cases in generally about the same time. There was a study

filed -- or not a study. A rate case filed in Montana that there will not be a depreciation study by the time that the Commission holds the hearing. We also filed a rate case in Wyoming. They have until June of 2003 to make a decision. I don't know yet what the status would be of the depreciation study in that case.

Q. And you haven't filed in South Dakota yet?

A. We have not yet filed in South Dakota.

Q. Do Montana or Wyoming require periodic depreciation studies to be filed like some states do on a semi-annual basis?

A. None of the four states that Montana-Dakota serves natural gas or electricity in requires a depreciation study.

Q. Was there any consideration during -- that you're aware of during the last few months that MDU considered delaying this rate case until the Commission could consider it as a whole as opposed to potentially having to do a couple of different rate cases?

A. Could you repeat that?

Q. Are you aware of any discussions at MDU -- have you considered at all kind of holding off on this once you became aware that you may not have a

large portion of your -- the evidence that you should have for a rate case available?

A. Well, we filed this rate case in April of this year. There are no statutory or legal requirements to file a depreciation study. So our filing is in compliance, if I understand, with the legal and statutory requirements. So I don't think that we were remiss in filing a rate case without a depreciation study because it is not required. I think you had another part to that question.

Q. Well, maybe just following up on that, I guess I wasn't implying that there was any legal requirement. It's just my own thought is that, potentially, MDU, being that this is their case and the burden of proof is on them, would want the best information available, but maybe -- I'm just going to close up here quick.

You had mentioned that there may be a number of scenarios that could happen as this plays out. Let's assume that the Commission decides a number of issues that are outside of the depreciation part of this case. I think that has to be done in about a month or so. Is that in November, I think? I can't remember what the exact time frame is that we have to have our decision out.

But -- and then do what MDU is suggesting, which is just kind of put aside the depreciation portion of this.

How does that then play out on December 31st beginning next year when you have a new depreciation study? What are the scenarios that could happen here?

A. Well, I think part of that is maybe off a little bit. Everyone seems to be presuming in this case that there will be -- that, one, the depreciation rates are going to go down when we do a depreciation study. And I don't think that's a presumption that we can make now. We've provided in this case a 1991 study, a fully detailed study, and we still at this point still stand on that study. We believe that it's still a good study and that is what we filed our case on and it's a good, detailed study based on many years, details going back many years, a lot of data, a very complete study.

Q. Okay. So let's go through the scenarios again. If it's the same and it shows the same as the 1991 study and if we accept that as part of this rate case, then nothing would change. If the depreciation changes so that it becomes, in effect, a rate decrease, then do you file updated tariffs

just decreasing their rates, decreasing the tariff rates?

A. I think I'm getting into an area that I think might be, as far as a legal area, as far as what the Commission -- you know, as far as issuing an order and after that. So I think that's really a legal issue and I don't feel that I can properly address that.

Q. Okay. But MDU could consider filing another rate increase if the depreciation schedules indicated that was appropriate, right?

A. Yes.

COMMISSIONER CLARK: Okay. That's all I've got then.

MR. HOBERG: Thank you, Commissioner Clark. Mr. Diller?

EXAMINATION

BY MR. DILLER:

Q. Ms. Mulkern, isn't it true that adjustments for inflation cause inflation? That's a question that Mr. Myer Shark used to ask all the time and I felt like we needed to get his name in the record.

And so isn't it true that -- would you agree that adjustments for inflation causes inflation?

A. I would not agree with that statement.

Q. Could you explain that, please? That's all right. I withdraw the question. I just wanted to have some fun. Let's see if I have a real question here.

I think based on the exchange I heard between you and Mr. Binek, if I could maybe characterize your response to him as there's not been any correlation between CPI and these other O&M expenses that haven't been inflated individually in the past, but you feel like CPI will be a fair indicator of what you can expect with these other O&M costs in the future; would that be a fair characterization?

A. I think that CPI recognizes that these costs are going to increase with time, with inflation.

Q. Now, have you done any long-term comparison between CPI and these other O&M expenses that are being talked about here, any long-term correlations to -- you know, I mean, certainly some years it will be because of efficiencies and this and that the company beats the inflation indicator, but have you done any long-term comparison to see if there's any long-term correlation between CPI and these other

O&M expenses?
A. Well, I'm not sure what constitutes long term, but I did look back to 1994, since the last rate case, at all these other items, and the increase is greater than inflation for the same time period.
Q. Greater than the CPI?
A. Yes.
Q. That's surprising. But we don't have any -- that's not on the record anywhere?
A. No. That was just something that I did on my own.
Q. Is that something that's available for providing to the Commission, or is that just something that you kind of did ad hoc and didn't really --
A. I have a workpaper on that.
Q. Would you mind providing that as a late-filed exhibit?
A. I can provide it.
Q. I mean, it's not really that long term, but it might be interesting to look at.
MR. HOBERG: That would be Late-Filed 5, Mr. Pearce.
MR. PEARCE: Yes.

MR. DILLER: That's all the questions I have.
MR. HOBERG: Thank you, Mr. Diller. Any further questions of Ms. Mulkern?
COMMISSIONER WEFALD: I might have one here. Just a minute.

FURTHER EXAMINATION

BY COMMISSIONER WEFALD:

Q. Go through with me again what expenses are covered under these other expenses where you have this list of them. Which exhibit is that?
A. Well, the one on the exhibit is Statement N, page 14.
Q. Page?
A. Statement N in the statement book. I think it's Exhibit 2.
MR. HOBERG: It's a big book, Statements A through O.
Q. (COMMISSIONER WEFALD CONTINUING) Yep. Statement N?
A. Page 14.
Q. Statement N, page -- like in no?
A. Like no.
Q. Page 14 of 23?
A. Yes.

Q. All right. So I'm seeing on this just cost of gas?
A. These are the items that we did adjust individually. These are the items that make up 71 percent of total operating maintenance expense.
Q. All right. What are the ones that are not?
A. The ones that are not are the ones in the last column that are left over after you adjust all the others separately and that's the one -- that contains such items as postage expense.
Q. Now, are you looking under all other O&M?
A. That's the one.
Q. But it doesn't have anything broken out as to what those include, so you are going to give me a list right now?
A. There are many items in this list. These are the ones that make up the 29 percent -- those five items make up 71 percent of all of the O&M, operating and maintenance expenses. All other items make up 29 percent.
Q. How do we know which ones are administrative and general of four-million-ninety and there's a separate list of ones that aren't covered? There's some under administrative and general that are covered and then there's some that

are not, $1,617,000?
A. Right. We started with our operating expenses in total for North Dakota gas by what we call function, distribution, customer accounting. And from that we deducted in the same by function, the labor expense.
Q. Do you determine which ones are not covered by this or did the Commission in its last case?
A. No. We looked at what -- kind of the major cost items, the ones that make up the majority of the costs. Five items make up 71 percent. So we looked at those five items specifically. Or I should say some we looked at for other reasons, like rate case expense, but we looked at those five items individually and adjusted those individually.
Q. I'm not following you at all. Are they -- rate case expense has --
A. Rate case expense is included in the administrative and general costs area and --
Q. One underneath that?
A. One. And that one we adjusted individually because we were looking at the cost of this rate case proceeding, rate case expense. So since we were adjusting that separately, we took it out.
Q. You've had other gas cases during this

time. I don't understand this chart. So maybe I should just visit with my staff, but I just don't understand the chart at all.

A. If I can explain, if you want me to answer.

Q. Keep going.

A. If you look in the left-hand column and it says "per books," those were the operation and maintenance expenses for 2001.

Q. All right.

A. And it shows it by function. For instance, the distribution, it covers all the costs in operating and maintaining the distribution system. Customer accounting is for all the billing related and, you know, accounting for the customer for that, and so on.

Q. The first one is a total of the other columns; is that correct?

A. No. The first column is a starting point.

Q. All right.

A. From there we were going to -- for instance, for costs of gas for projected 2000 and 2003 we calculated that so we adjusted it individually so we deducted it from the total because we're doing that someplace else, we don't want it in this adjustment. Next, we looked at

labor and, again, we're going to adjust that separately, so we're going to deduct all the labor costs from this total per books amount. And labor goes into all the functions also.

We went down, continued with benefits, which is all charged to an administrative and general account because we adjusted the items and benefits separately. And then insurance we looked at separately. And rate case expense and advertising. So we started with the total per books, we adjusted everything we were going to look at separately, and what's left over is that 29 percent I referred to and this is what we applied inflation to, these costs that were remaining after we adjusted certain items individually.

Q. So the cost of gas is $76,000. Is that one of them then?

A. That was -- yeah. That's what we had in 2001 for gas costs.

Q. $7,988 of labor, is that another one, or am I wrong?

A. No. That was labor expense for 2001.

Q. I don't get the chart, but I'll work on it later. Thank you. I don't understand it. But thank you very much for trying.

MR. HOBERG: Any further questions of Ms. Mulkern? Thank you, Ms. Mulkern. You have three witnesses left?

MR. PEARCE: Yes.

MR. HOBERG: And a short time to do them in. Next one is Ms. Aberle.

MR. PEARCE: Call Tamie Aberle. And I have one -- I have a one-page exhibit.

(Exhibit 37 was marked for identification.)

MR. HOBERG: Ms. Aberle, you also testified yesterday. I just need to remind you, you are still considered to be under oath. Mr. Pearce. Her rebuttal is Exhibit --

MR. PEARCE: 26.

MR. HOBERG: -- 26-52.

TAMIE A. ABERLE,

having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Ms. Aberle, you prepared for this case, did you not, a prefiled written rebuttal testimony?

A. Yes, I did.

MR. PEARCE: And that's been marked Exhibit 26. I'll offer that.

Q. (MR. PEARCE CONTINUING) And ask you to summarize your testimony briefly.

MR. HOBERG: Any objection to 26?

MR. BINEK: No.

MR. HOBERG: 26 is admitted.

MR. BINEK: Has this been marked as an exhibit?

MR. PEARCE: It's marked 37.

MR. HOBERG: He hasn't offered it yet.

THE WITNESS: I will begin with why I do not agree with Mr. King's position regarding the allocation of mains and the class costs of service study. The company has proposed an allocation of mains based on a customer and demand component. Mr. King advocates that it is not correct to allocate a portion of mains on the customer component. We believe it is appropriate to do so and it is a practice that is used in the gas industry and is supported in a report prepared by the NARUC staff subcommittee on gas. And I've included some references in my rebuttal testimony, Exhibit 26. We did prepare a study that indicates that approximately 36 percent of the mains investment should be allocated to the customer component.

Also, Mr. King suggests in his testimony that main additions are only made at the very edges of the system to provide service to new developments. In our system, main additions are also required for purposes of enhancing system integrity and maintaining pressure requirements throughout the system as customers are added. Main additions -- main investment is not a variable cost that increases or decreases as more or less gas is used. Also, the concept of value of service is not appropriate for allocating embedded costs as Mr. King advocates. The value of the heating content of gas does not represent the company's embodied costs or the causation of that cost.

Secondly, with regard to the allocation of mains, the allocator used by Mr. King includes total throughput for the energy, which results in excessive amounts of mains being allocated to the interruptible customers who are not utilizing the distribution mains in order to receive natural gas service. We have a number of customers that are connected directly to the transmission system and there are no mains associated with serving those customers.

I have prepared a study reflecting 50

percent allocation based on throughput at distribution level and 50 percent at the peak day used for the firm customers, and those returns are reported in my testimony. The results are that -- results in higher returns for the Air Force and the interruptible classes, which are those classes that have a larger percentage of customers connected directly to the transmission system.

I also do not agree with Mr. King's allocation of the rate increase, based on either the company's class cost to service study or a class study based on Mr. King's proposed allocation as modified and as set forth in my Exhibit TAA-4. An increase to the Air Force small interruptible or large interruptible class is not warranted. The subsidization provided by the interruptible classes should not be increased by allocating another increase to those customer classes that are already providing a return on rate base higher than the overall return. The increase -- any increase in revenues to this class is also at risk given the flexible rate provision applicable to the interruptible customers. Presently, approximately 20 percent of the small interruptible class and 80 percent of the large interruptible volumes are

transported under discounted rates.

Finally, the Commission did authorize allocating the entire increase to the firm customers in the last rate case.

Now, I'd like to address customer impact discussed by Mr. King yesterday in his testimony. I think it's best to focus on the dollar value impact, rather than the percentage increases. And, also, the rate proposal must be looked at in its entirety to talk about customer impact. I'd like you to take a look at the exhibit that was just handed out marked as Exhibit 37, or TAA-6. This is the same exhibit that is in my direct testimony as Exhibit TAA-2. I've simply added two lines that I think help to portray better what the impact of the rate proposal has on the residential customers.

COMMISSIONER WEFALD: This is TAA --

THE WITNESS: Dash 6. The one that was just handed out --

MR. HOBERG: It's a single sheet.

THE WITNESS: -- to you as a single sheet. This is a representation of a customer's bill under current rates and under the proposed rates as filed. And this is a typical, average residential customer using 110 decatherms. And it is meant to represent

how that gas is used throughout the year. If you look at the line that I've added, base rate as percentage of total, it's indicating that under the proposed rates, our basic service charge or our fixed component of our rate would collect about 28 percent of the total customer's bill versus 16 percent under the present rate. So as shown there, it's not in the high percentages I believe were discussed yesterday.

Also, corresponding with the increase in the basic delivery charge is a decrease in the distribution delivery charge or the commodity, the variable part of the rate. And I've shown on that second line that the non-gas commodity portion of this customer's bill would decrease by $37 under this example or approximately 44 percent.

A couple of other items I'd also like to point out. The increase to the customers, as we've noted to a residential average customer would be approximately $24. As shown in the amount of increase column, the highest increase would be in the summer ones when they are using less gas, but that increase would only be $4 in those months.

And as shown in my rebuttal testimony, Exhibit TAA-5, there's another bill comparison,

which just shows varying levels of consumption, because, as we know, there's customers above and below this. As shown in that Exhibit TAA-5, if a customer used zero volumes through the entire year, their increase per month would still be only $5.20.

MR. HOBERG: That's the last page of your --

THE WITNESS: Last page of my prefiled testimony, rebuttal testimony.

This rate form also provides customers -- or still provides customers with an incentive to conserve natural gas because each decatherm of gas that they conserve, there's still a reduction of $3.33 associated with that less gas use. And that is the combination of the distribution delivery charge and the cost of gas. So they're showing that still the majority of the customer's bill is still a variable component.

What the proposed price structure will do is provide relief to customers during the winter months when their heating requirements result in higher gas use by lowering the amount collected on the volumetric basis and sending an accurate price signal by accurately reflecting fixed costs in the fixed cost component.

Just a couple comments with regard to the distribution delivery stabilization charge that was presented in -- by direct testimony. The company has proposed to implement such a mechanism if the proposed base rate levels are not approved. And I also just wanted to comment that the deferral-type mechanism will not result in significant impact as suggested by Mr. King. As shown on Exhibit No. 8 in Mr. Feingold's testimony, based on -- where we did an example based on historic results, the amount charged per bill will be minimal and significantly less than most PCA changes. In that example, over the four-year period reviewed, a residential customer would see a monthly bill change ranging from a negative 20 cents to a positive 84 cents. And that was a bill change, not an amount per decatherm.

And, finally, I wanted to just comment on the company's proposal to build a basic service change on a daily basis versus a monthly charge as done today. And the only reason for proposing this change was to provide better information to those customers that are cutting in and out of service and are receiving bills for less than a normal billing period. The proposal will not affect our meter

reading or billing schedules.

That's all I have for my summary.

MR. HOBERG: Are you offering Exhibit 37?

MR. PEARCE: I'm offering Exhibit 37. I have no other questions.

MR. BINEK: No objection.

MR. HOBERG: Okay. Exhibit 37 is admitted. Thank you, Mr. Pearce. Mr. Binek, do you have any questions of Ms. Aberle?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. King has proposed increases in customer charges, hasn't he?

A. Yes, he has.

Q. Specifically, he proposes that even if rates are decreased, the volumetric rates should be flattened and the initial block revenue be recovered through increases in the customer charges; is that correct?

A. Yes.

Q. Do you agree with that recommendation?

A. Yes. At a minimum I believe that should be done.

Q. Mr. King also recommended that if rates are

increased, the increase in customer charge should be twice that of the volumetric rate.

Do you agree with that?

A. I agree if the proposal is -- the rate increase is approved as provided, that our base rates would be approved.

Q. Okay. Well, it isn't nearly as much of a customer charge increase as you propose. Would you agree that Mr. King's proposal moves in the direction of the rate design changes the company is seeking in this case?

A. I would agree that it moves in the direction.

Q. Are the proposed movements toward the company's preferred rate design sufficient to permit the company to withdraw its DDSM proposal?

A. I could not answer that at this time.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. Yes. I'd like to ask a few more questions about this monthly charge divided into a daily charge. Tell me about the people. You say these in

and out accounts. I would like to have a little information about that on the record.

A. The accounts we're talking about are people -- you know, in the fall college students. We get a lot of people in and out. They may move in in the middle of the month versus the beginning of the month.

Q. So what happens at this point --

A. If you are less -- excuse me.

Q. -- if I would move in on the 15th?

A. We have a normal billing cycle, which is 28 to 32 days. If you're outside of that normal billing cycle, your bill is prorated. So that if you're only in service today for -- in service under today's rates for 10 days, you'll receive 10/30ths of the customer charge on your bill. But that bill -- the way that is presented on the bill, because of the way -- it's a proration. Our customer charge is a monthly charge. So it's a combined number on the bill. It shows -- it's combined with the amount of customer charge and usage at that premise for that time period.

And the daily charge would simply allow customers to see the number of days in the bill cycle, which is presented on the bill today, and

multiply that by the charge that's in effect, the daily charge that's on the tariff sheet, if approved, and be able to calculate that amount. It's simply an informational item. The real crux of our proposal is the amount of the increase and not so much whether it's billed or presented on a daily basis versus the current monthly charge. It really will not impact the revenues we collect or the amount customers pay. It's really an informational item.

Q. I understand that. So if you're giving these people who only are using service less than a month and they are already receiving a different amount than the total amount on their bill, then we can just figure that those people are taken care of already?

A. Mm-hmm.

Q. So --

A. It's just information for those people.

Q. So don't you think -- well, so you don't really care whether or not -- you're telling the Commission you don't really care whether we do this on a daily basis or on a monthly basis, as long as the costs come out the same for customers throughout the year?

A. I would rather have the increase on the base, the fixed charge, the monthly amount. And the other was just a move toward trying to provide more information.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark.

COMMISSIONER CLARK: I have no questions.

MR. HOBERG: Thank you. Any further questions of Ms. Aberle? No questions. Thank you, Ms. Aberle.

I think perhaps we should just take -- for the court reporter's benefit take a short break right here. A strict five minutes.

(Recess was taken.)

MR. HOBERG: We are back from a short recess. Your next witness, Mr. Pearce.

MR. PEARCE: I call Mr. Spratt.

MR. HOBERG: Mr. Spratt, I don't think you've been sworn in.

THE WITNESS: No, I haven't.

MR. HOBERG: Were you here earlier when I gave the admonition in regard to perjury today?

THE WITNESS: Yes, I was.

MR. HOBERG: Being advised of the penalty

for perjury, do you promise to tell the truth in that matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce.

RICHARD D. SPRATT,

being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Spratt, you have prepared written rebuttal testimony that's been filed in this case, have you not?

A. Yes, I have.

Q. I'll ask you to just briefly state your name and business address and what your position is with the company, and then if you could summarize the important points in your written rebuttal testimony.

A. Okay. It's Richard D. Spratt. My business address is 400 North Fourth Street, Bismarck 58501. I'm vice-president of human resources for Montana-Dakota Utilities, which is a division of Montana-Dakota Resources Group, Inc. My responsibilities include benefits and compensation, staffing, organizational development, behavior, labor and

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employee relations.

Q. Thank you. Would you summarize your written testimony then?

A. Yes, I will. And I basically would like to make just a couple points. I'm here basically to refute Mr. Majoros' -- am I saying that right? -- his sort of unsubstantiated statement that we should eliminate bonuses and hold 2003 labor costs equal to 2002.

Let me start with the bonuses. Basically, we have bonuses as part of a total compensation program, which includes not only bonuses, but it also includes your base salary and your benefits and a certain portion of that salary is what we call at-risk. And we do that in varying degrees with different employees based on what's competitive. And that's my first point is that, you know, we see this to use in a competitive way. It makes us competitive and attracts and retains employees for us and so that's, A, why we have a bonus. Now, B, another reason why we do is it sort of focuses employees in on those areas that we need them to focus in on, particularly in recessionary times, to try to save costs and/or at least reduce costs and have it more efficient. So that's my first one,

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bonuses.

Second one, compensation, where he says that we basically should hold the 2003 labor costs equal to 2002 level. A couple of things there. First of all, again, we use as part of a total compensation package a base is a portion of that total compensation package and to be competitive and to attract and retain employees, we need to have competitive wages and salaries. And right now -- along with that, we do what we call a compa-ratio analysis to see just how competitive we are. We also use about 11 different surveys that will show us degrees of competitiveness in various areas, including our engineering and our IT staff and our administrative staff. And the compa-ratio analysis that we've done shows that we're really behind competitively, not only in our industry but in general industry in terms of what we've done. So I think in -- to go back a little bit, in 1996 when we started on this -- really started tightening down and started trying cost efficiencies and, you know, looking at costs and one of the things that we did is we started holding our labor costs down quite a bit. And we've gotten behind over the years because of that.

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To say that we should not increase or we shouldn't grant, I guess, an increase in labor costs is tantamount to making us fall back another probably -- in one case, in the executive case it would be somewhere in the neighborhood of going from 11 to 15 percent behind. And then in the office and administrative it would be about 9 percent behind. So in those two areas, you know, I think we need to -- it's our belief we need to continue to do what we're doing primarily to get the efficiencies.

Another way we can do this, though, is we could -- particularly with bonuses, is we could build that into our base structure, which basically would cost more money then and that wouldn't be very good for our customers because that has to be passed along as well.

The last thing I'll say is that it's my understanding that the Commission ordered Case No. PU-399-01-186 has allowed these kind of costs and expenses before. With that, questions?

Q. (MR. PEARCE CONTINUING) Just one question, Mr. Spratt, to clarify. Why would it cost more to package all of the compensation into wages or salary rather than bonuses?

A. Right now we have a certain -- in the

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beginning I said we had a certain portion of our salaries that are at risk and that -- it's dependent on how we perform against financial goals, as well as -- excuse me -- goals that are personal goals that are set up, cost goals, usually. And that's to make us perform better and to be more efficient. But if we just took those and that's at risk, and if we don't -- if we don't achieve those goals, then we don't get paid that portion of it. So if we just rolled it in, that would obviously make the cost of our payroll go up.

MR. PEARCE: Okay. I'll offer Exhibit 27. I have no other questions.

MR. BINEK: No objection.

MR. HOBERG: Exhibit 27-56 is admitted.

COMMISSIONER WEFALD: Where is 27?

MR. HOBERG: 27 is the rebuttal testimony of Richard D. Spratt. Mr. Binek, do you have any questions of Mr. Spratt?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Spratt, what was the total amount of bonuses and commissions awarded last year?

A. Dollar?

Q. Yes.
A. I don't know.
Q. Would you accept $518,000 as the amount, subject to check?
A. I honestly don't know.
Q. Okay. Do you know how much of the -- of the amount was commissions and how much was bonuses? I assume since you don't know the amount, you probably don't know that, either.
A. No.
Q. Would you be able to tell us what the percentage split would be between commissions and bonuses?
A. No. In fact, that commission kind of throws me. I'm not sure -- I know I saw it in here. I think when we're talking about commission, we're talking about incentive and bonuses, period. We don't really have anybody on commission, that I'm aware of. So this would be, in fact, 100 percent bonus.
Q. Okay. And then on page 4 you state 60 percent of hourly employees, 75 percent of salary employees and 90 percent of management employees are eligible to receive bonus. What determines these percentages?

A. Well, those were done -- those are basically surveys that we've done, that we're a part of and that shows that these are the percentage splits that are partaking in bonuses.
Q. Surveys taken of whom?
A. Various companies, including our own, the utility industry.
Q. But these percentages apply to MDU, not to other companies, right?
A. No. No. These percentages apply to other companies. If you took the total of the companies in our surveys, if you go back to -- refer back to in my testimony the back page there, you can see if you go down to utility and energy section and you just take the 20 -- on the left-hand side you'll have industry sectors, utility and energy. What they're showing there is in the utility and energy sector -- well, it shows all -- a number of sectors, but particularly in the utility and energy sector, they're saying that there's an average. If you're in the 30 to $39,000 range, there's a 62.7 percent of those companies are offering bonuses. For 40,000 or more it's 75 percent.
MR. HOBERG: Just for the record, you're at RDS-1, page 1 of 3, on the back?

THE WITNESS: Yes. There's no page number on it.
MR. HOBERG: It's up at the top, RDS-1, page 1 of 3, right-hand corner.
THE WITNESS: Oh, yes. Yes, that's it. That's RDS-1. And then RDS-2, if you go over, they'll show that the utility and energy sector and it gives a number of responses up at the top and the sample was 1,149 companies, of which 76 were utility and energy and 91.2 percent of those offered. So these numbers are industry numbers. They're not our numbers. Our numbers are a little different.
Q. (MR. BINEK CONTINUING) Okay. So what percentage of hourly employees at MDU receive those bonuses, commissions, whatever they are?
A. 100 percent.
Q. Okay. And salary employees?
A. As well, 100 percent.
Q. And management employees?
A. 100 percent.
Q. So all employees are eligible to receive?
A. All employees are eligible, correct.
Q. Within each category that's eligible to receive bonuses, what proportion typically receives them in each year?

A. I'm not sure. I can tell you approximate percentage, but I'm not sure how many.
Q. Give us the approximate percentage.
A. Well, to give you an example, two years ago 75 percent of -- 75 percent of our total employee population eligible for the BETA received a 7 percent bonus. And then last year it was about -- overall it was about six-tenths of a percent that they received.
Q. Okay. Again, 75 percent of the -- is it 75 percent of all employees --
A. Yes.
Q. -- received these bonuses?
A. That's correct.
Q. And it was 7 percent, and what was the figure last year?
A. Last year was six-tenths of 1 percent.
Q. Okay. Does the total amount of bonuses awarded each year typically remain the same, or does it vary from year to year?
A. The number of bonuses?
Q. Total amount of bonuses.
A. The total amount. It would vary some year to year, depending on how we did against our financial goals and how we did against our personal

goals.
Q. Does the total amount of bonuses vary among the three categories of employees, the hourly, salaried and management?
A. Yes, it would.
Q. Do the same employees typically receive bonuses each year?
A. Overall I would say, yes. I mean, 100 percent of our employees are eligible for bonuses and so, I mean, there are some that will -- particularly, if we meet our financial goals, everybody shares in that one, but if they don't hit their personal goals, they wouldn't share in that portion of it.
Q. At the top of page 7 you state that the annual wage increases each year have averaged 3.7 percent over the last five years. According to our calculation, that would mean that over the total five-year period MDU has increased wages by 20 percent. Would you agree?
A. Yes, approximately.
Q. Have bonuses increased proportionately?
A. No. Bonuses have been up and down. I mean, one year -- like I said, last year it was very low. The year before that it was fairly high.

Q. During the past five years has MDU received any increase in its gas rates?
A. I'm not aware of that.
Q. In fact, in 1998 the company agreed to a gas reduction; isn't that true?
A. I don't know. I've only been here for about a year and a half.
Q. So you wouldn't know when the last gas rate increase was?
A. That's right.
Q. Okay. Would you accept, subject to check, that the last case was decided on November 23, 1993?
A. Would I accept that?
Q. Yes.
A. Certainly, yes.
Q. Has the company increased wages each year since 1993?
A. No, I don't think they have. Actually, we had a freeze, I know, for a while and, again, that's -- I'd have to defer that. We had a freeze on wages there for a while, I know.
Q. But over the last five years you did agree that the increases have averaged 3.7 percent each year?
A. Yes.

Q. Okay. How has the company been able to hold retail rates level and, in fact, reduce them while increasing wages each year?
A. Part of that, I think, goes to the fact that we've just become much more efficient. If you look at our population, we've decreased over the years. And, you know, we've asked our employees actually to do more and then technology has also helped us out in that respect.
Q. In other words, you've been able to improve labor productivity over these past years sufficient each year to offset the annual increases in wages, salaries and bonuses; is that correct?
A. I don't know if it completely offsets it, but, yes, essentially, you're correct. We've increased our labor productivity.
Q. Where in this case do we see a forecast of the productivity offset to the wage and salary increases you predict for the year 2003?
A. Where?
Q. Yes.
A. Say that again, please.
Q. Where in this case is there a forecast of a productivity offset to the wage and salary increases you predict for the year 2003?

A. There isn't one per se. We have goals and objectives, however, that -- in fact, we're formulating those right now -- that will hopefully get us some of that offset.
MR. BINEK: Thank you. I have no further questions.
MR. HOBERG: Thank you, Mr. Binek. Commissioner Wefald, do you have any questions of Mr. Spratt?
COMMISSIONER WEFALD: Yes.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. Where is the data on labor costs and bonuses in this case?
A. Where's the data?
Q. Mm-hmm.
A. I'm not sure. We can get that data, if you need it.
MR. HOBERG: Mr. Pearce?
MR. PEARCE: I imagine it's in the statements.
MR. HOBERG: Statements A through O?
MR. PEARCE: Somewhere in there. I think Ms. Mulkern testified to it and that would identify which of the statements or schedules it's in.

THE WITNESS: Are you talking about the numbers themselves?

Q. (COMMISSIONER WEFALD CONTINUING) Yes. For 2000, 2001, 2002, 2003.

A. Okay.

Q. Where would I find the breakout of the numbers of labor and bonuses in this case?

MR. PEARCE: Perhaps we can have Ms. Mulkern point us to that. Perhaps we can find it here. It's certainly in these statements of the expense items. I'll see if we can find it. It's just been pointed out to me from both sides. In Statement N, page 7 of 23 and --

COMMISSIONER WEFALD: Statement N, page 7 of 23.

MR. PEARCE: I don't know if the witness has the exhibit up there. I'll give him this copy.

Q. (COMMISSIONER WEFALD CONTINUING) So am I correct then that the labor expense in 2001 includes bonuses as well? Bonuses as well as other labor expense?

A. Reflects average -- yes, 3.15 increase reflecting average 2002 bonus. Footnote 1 there.

Q. Well, it doesn't tell me the exact amount that was paid out in bonuses during that time, does

it?

A. 3.15 percent, but it doesn't give you the dollar number, you're correct.

Q. But it says that that reflects an average 2000, 2002 bonus?

A. Yes. What was your question?

Q. My question was, does this chart tell me how much was paid in labor and how much was paid in bonuses in the year 2001?

A. Year 2001, it does not, it appears. I'm sorry. No, it does. It's 2001, 2002, but it just gives you the average of the increase. It doesn't break out bonus and dollar.

MR. PEARCE: I think if I may interject, it's -- labor expense isn't broken out, I don't think, anywhere in those statements. That would have to be extracted from the company records. I guess it could be done.

MR. HOBERG: Is that something you'd like to see?

COMMISSIONER WEFALD: Well, I think it would be helpful because the company -- the staff is arguing that we should eliminate bonuses and they have a number. They're saying that it's half of the increase or something that's projected -- I saw that

number someplace. Just a moment. In Mr. Majoros', on page 15 it says, it is unreasonable to be granting bonuses which, in fact, amount to roughly half of the company's overall requested increase when the company is proposing a rate increase to begin with. So I'd like to know what those numbers are so that I can understand better when he talks about it's roughly half of the company's overall requested increase. I'm assuming in labor costs.

MR. HOBERG: Mr. Pearce, can you provide that?

MR. PEARCE: I assume we can. We'll certainly try to provide that number. That would be 6, I think.

MR. HOBERG: Late-Filed Exhibit 6.

Q. (COMMISSIONER WEFALD CONTINUING) So perhaps it would be helpful to have the actual numbers for 2000 and 2001. We don't -- do you know what the numbers are yet for 2002, because we are not at the time end of the year?

A. No, we don't know that now. We wouldn't have the actual until after --

MR. HOBERG: Could you project those out, though, on --

THE WITNESS: We could, yes. It's not

looking good for this year.

Q. (COMMISSIONER WEFALD CONTINUING) And then if you'll explain to me what MDU is doing here. Are you -- in your calculation on page 7 of 23, Statement N, explain to me how you're doing this.

A. Give me that cite.

Q. That same page that we were looking at.

A. Seven.

Q. Okay. So you're just taking from $7,988,000 for labor costs in 2001, you're putting in place a 3.15 percent increase for year 2002 and then you're projecting a 3 percent increase for January 1st, 2003?

A. That's correct.

COMMISSIONER WEFALD: Okay. Thank you.

MR. HOBERG: Commissioner Clark, any questions?

COMMISSIONER CLARK: Just a couple.

EXAMINATION

BY COMMISSIONER CLARK:

Q. When calculating the C ratio compa-ratio, is the term "market value," is that the same as market average? In other words, when you say 91 percent of the market value, is that saying you're 90 percent of the market average for a given

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position or wages?
A. Essentially, that's correct. We're at midpoint market average or market value. It's the midpoint of that.
Q. Okay.
A. We're 91 percent of that.
Q. Got it. And that's companywide, it's across the board?
A. That's right.
Q. Would that follow that individual positions are typically at about that or are there certain areas of --
A. Lower and higher. And more lower than higher, though. Because if you took 100 percent, that would mean that everybody was right at the midpoint of their salary range or that market value of their salary range.
Q. Do you have any particular area of expertise that tends to be more of a problem where you are at with midpoint than others?
A. Well, if you read further, you'll see that the managers are actually lower paid, I think. That's probably where we have more of a problem.
Q. Do the C ratios or compa-ratios, include bonuses, or is that just salary?

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A. No, that's just salary.
Q. Is there any way to get a handle on what the bonuses, kind of where that brings it? Because it would seem like if the company has a policy which is trying to move more toward bonuses, which in a lot of ways make sense because it's more incentive based and it has some tax advantages or some savings advantages, when you add those in, where do salaries fall?
A. Well, if you take the total compensation package, you know, and you look competitively, you'll see that in various classifications, they'll have different bonus amounts. Overall for mid managers, what we call mid managers -- executives are a little different -- mid managers, but we use about a 15 percent average and that's based on, again, study from Towers Perrin and --
Q. So explain, a 15-percent average means 15 percent of their total compensation package?
A. 15 percent of their base salaries.
Q. 15 percent of their base salaries is?
A. And that's really at risk. I mean, that's -- you know, they have to perform to get any of that.
Q. Okay. I think you're going to have to

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explain this 15 percent again. It's 15 percent of their base salary?
A. Base salary, right. That's what they're eligible to receive.
Q. In bonus?
A. Up to 15 percent of their base salary and that's for the middle management.
Q. And you said that rate is comparable to other industry peers?
A. That's -- yeah. That's -- in fact, it's probably a little bit low. If you look at the study, they're going to come in somewhere between 17 and 22 percent.
COMMISSIONER CLARK: That's all I've got. Thanks.
MR. HOBERG: Thank you, Commissioner Clark. Commissioner Wefald.

FURTHER EXAMINATION

BY COMMISSIONER WEFALD:

Q. So if I'm to assume that in 2001 on this same page 7 of 23, Statement N, that a certain amount of dollars are already in 2001 for bonuses?
A. 2001?
Q. Mm-hmm.
A. Those are actuals, I think, aren't they?

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Q. Those are actuals in 2001. The actual bonuses that were given in 2001.
A. Right. I'm assuming that's what they are. I didn't make this chart, but since that's past.
Q. So each year you're projecting to give more bonuses, if you put in the increase of the 3.15 percent, is that correct? In the first year to 2002 and 2003 you would be giving each year a greater amount -- have the potential to have a greater number of dollar bonuses in those three years?
A. Let me see if I can clear this up.
Q. Let's say there's $500,000 of bonuses in the first year.
A. Let's start with $1,000. It's easier for me to calculate. Let's say we have a $1,000 worth of -- well, first of all, let's say we have $2,000 worth of salary, period, and we give a 3 percent increase across the board to those $2,000, so that would be $60. So now we have $2,060. Now, if you assume -- you've got the 3 percent of 2,000 would be 60, 3 percent of 2,060 would be something a little more than that. So you're right in assuming that if you give increases, that providing -- and there's nothing guaranteed about these bonuses. If you hit your maximum, then your bonuses would also increase.

Q. But if Mr. -- is it Mr. Majoros who was discussing this in his testimony? Is it your understanding that he's recommending eliminating the entire dollar amount of bonuses out of 2001, or is he just recommending that there not be an increase in the dollar amount of bonuses that's included in 2001?

A. I'm not sure. 2001 is by us so now --

Q. Yes, last year. And your chart here is based on 2001 and then you're making an adjustment, reflects an average of 3.15 percent increase.

A. Over the actuals paid in 2001.

Q. Reflects average 3.15 percent increase reflecting average 2000, 2002 bonus.

MR. PEARCE: I think we may be getting stuck here. Perhaps Ms. Mulkern could come back because she's the one that prepared --

COMMISSIONER WEFALD: Okay. That would be good.

MR. PEARCE: Maybe you can get through this a little faster.

MR. HOBERG: Ms. Mulkern, do you want to come back up? Let's do it right now while we're on the subject. If you could stand up there by the mike, please.

MS. MULKERN: Can I describe maybe how we developed that labor increase?

COMMISSIONER WEFALD: Sure.

MS. MULKERN: Okay. We started with 2001 actual -- in developing a labor adjustment, we started with the actual gas utility labor expense, total company gas utility for 2001, and that contained the payroll over time, these commissions and bonuses, and we use that title. It really isn't bonuses. It kind of carries over from previous years. And looked at 2001, and then we looked at 2002, what was in the budget. And in 2001 we had a higher bonus payout and so if we stayed with the 2001 amount and increased that, really, we would be overstating. So we included a three-year average of bonuses and used a three-year average of bonuses for 2002, 2001, and 2000 and included that as the bonuses for 2002.

So the 3.1 percent -- 3.15 percent increase reflects a three-year average of bonuses in it. So the bonus level for 2000, indirectly 2002 that's embedded in that is less than was actual in 2001 because instead of using the actual bonuses, we restated it to a three-year average.

COMMISSIONER WEFALD: So there is money in

2001 here for bonuses and 2002 you altered the amount of bonus dollars in these and then you also figured a 3.5 percent increase, not only on the bonuses, but on all labor costs?

MS. MULKERN: The 3.15 increase for 2003 is net of the bonus. It's not on top of it. It's net of the change in bonus. So that's the overall increase in all labor and reflecting a three-year average.

COMMISSIONER WEFALD: All right. And then what happens in 2003?

MS. MULKERN: And then in 2003 we adjusted everything up by 3 percent. And that makes sense because everyone's wages are going up and so, generally, the bonus is based on the percent of base salary. So that base goes up and the bonus will go up. If I got, say, a .5 percent bonus in 2002 based on my 2002 salary and, hopefully, I would get a wage increase in 2003 and I got the identical percentage bonus, it would be higher cost because my wage has gone up. So it is appropriate to increase the bonus rate 3 percent, because the overall wages are going up, therefore, the bonus would go up also.

COMMISSIONER WEFALD: All right. I understand it. Thank you.

MR. HOBERG: Thank you, Ms. Mulkern. Any further questions then of Mr. Spratt? Mr. Diller.

MR. DILLER: I see it's after 5:00, but I do have a question.

EXAMINATION

BY MR. DILLER:

Q. Is it true, Mr. Spratt, that wage increases are a cause of inflation?

A. No.

MR. DILLER: I withdraw the question.

MR. HOBERG: Any further questions of Mr. Spratt? Thank you, Mr. Spratt. You've got one witness left?

MR. PEARCE: Call Richard Espeland. Should be very short, I think.

MR. HOBERG: Mr. Espeland, I just need to remind you also that you're still considered to be under oath from yesterday.

THE WITNESS: That's correct, yes.

MR. HOBERG: Mr. Pearce, please.

RICHARD A. ESPELAND,

having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Espeland, for this case you prepared written prefiled rebuttal testimony, did you not?

A. Yes, I have.

MR. PEARCE: And that's been marked as Exhibit 28, I believe. I'll offer that exhibit and I have no further questions.

Q. (MR. PEARCE CONTINUING) Would you please give a summary of your testimony?

MR. HOBERG: Before you do, any objection to Exhibit 28?

MR. BINEK: No.

MR. HOBERG: Exhibit 28-55 is admitted.

Mr. Espeland, please.

THE WITNESS: Thank you. In my written testimony -- and I'll very briefly summarize and refer mainly to the attachments, which provides us supporting information, because I know in making rate case decisions what common practice is, sometimes needs to be supported. If you look at the Exhibit RAE-2, I provided two survey sources to support the common approach using a SERP or a supplemental income security plan for senior management.

If you look at page 2 of 3 of Exhibit RAE-2 you notice from the Hay survey under the left-hand column under non-qualified plans, it says, 74 percent of plan sponsors have some form of non-qualified retirement plan. So three-fourths of the employers have these types of plans. They're very common. Also, if you look at the right-hand column of the survey highlights, the second bullet from the bottom says, target retirement ratios fall into the 50 percent to 70 percent range, and so that a 50 to 70 percent replacement ratio for retirement income is very common.

On page 3 of 3 is another survey of another survey of another consulting company, Clark/Bardes Consulting. They also, if you look at the plan prevalence, have shown that in 2001 on the left-hand bar, 75 percent of the companies surveyed also have these type of plans. If you look up at the top introduction, the last -- on the right-hand column, about halfway through that paragraph, it says, the primary reason for adopting a SERP is the Omnibus Budget Reconciliation Act of 1993, which lowered calculations to 150,000. And at the time prior to that the index was 225,000. So they reduced by over a third the amount of compensation that could be

considered in a defined benefit pension plan. That was in part what caused these plans to be added.

If you then turn to RAE-3, the next page, which is a graph that shows the percent retirement replacement income, I've shown there on the top ones that qualified plans as to what percent replacement income they provide, and you can see 30,000 is 84 percent, and at the top level it's 20 percent, well below the 50 to 70 percent that is common.

So that's why we have our SISP program and that's why it's appropriate to include in the rates as a common practice as part of the total compensation program. And the bottom graph reflects how it changes when you add SISP. I believe the prior testimony said that we have an inverse relationship with our SISP where the lower level gets a smaller percentage replacement income under SISP and the higher level gets a higher percentage, and that's correct, but that's only a small part of the total picture. You've got to keep things in context.

There are four major parts to our retirement plan. Social Security, and you'll see the inverse relationship there where 40 percent out of the $30,000 level is provided by Social Security,

but only about 3 percent at the top level comes from Social Security. And same with the other plans. Our 401(k) plan has 20 percent provided at the lower income levels, and 8 percent at the higher level. Twenty-four percent comes from the defined benefit pension plan on the lower level and only 9 percent at the top level. That's why we have the SISP, to be fair and competitive and have a reasonable amount of replacement income at the 50 percent level at the top end, which is at the low end of the range of common practice.

Again, I want to emphasize as Mr. Spratt has commented, that we approach compensation in a total compensation approach. We can deliver $1,000 in a lot of different ways. We choose to offer base salary. We choose to have incentive pay so it's not a fixed cost, but it's only given if performance is there. And we choose to have benefits and other programs that provide for economic security. It's the most cost-effective way of doing -- delivering value to the executives and to the employees at all levels. And we could easily pay them all in base salary, all in base rate. It would not be the most cost-effective or the most incentivizing for good customer service.

That concludes my remarks.
MR. PEARCE: I'll offer Exhibit 28. I don't think I did before.
MR. HOBERG: You did.
MR. PEARCE: I didn't mark it. I have no further questions.
MR. HOBERG: Mr. Binek, any questions?
MR. BINEK: This has been covered pretty thoroughly, I think, and I'm going to resist the temptation of asking any questions. So I have no questions.
MR. HOBERG: Thank you. Commissioner Wefald, any questions?
COMMISSIONER WEFALD: I have no questions of this witness.
MR. HOBERG: Commissioner Clark, any questions?
COMMISSIONER CLARK: None. Thank you.
MR. HOBERG: Thank you, Commissioner. Mr. Diller, no questions? No one else has any questions of Mr. Espeland? Thank you, Mr. Espeland.
COMMISSIONER WEFALD: I have one for Mr. Spratt.
MR. HOBERG: Mr. Spratt, Commissioner Wefald would like to ask a question of you.

COMMISSIONER WEFALD: One more.
THE WITNESS: Am I still under oath?
MR. HOBERG: Yes, you are.

FURTHER EXAMINATION

BY COMMISSIONER WEFALD:

Q. Why should the Commission consider 2002 in an average for bonuses when you haven't even completed the whole year?

A. Because we started out last year and told our employees that there was going to be a bonus program. And in that bonus program we have objectives that they're meeting and there are certain financial objectives that we have to meet, as well as personal objectives. So in order for us to be able to keep our promise to our employees, I would like the Commission to do that.

Q. Well, we're not going to be approving anything that would go into effect for 2002. Our earliest date of the order would be --

A. 2003.

Q. Isn't that the year that we're looking at?

A. Yes.

Q. So it wouldn't make any difference what the Commission did for 2002. So we have to make our decision before the end of 2002 and you have to make

projections of what people are going to be getting, but how do we know you are actually going to be giving those bonuses or that people will actually meet the requirements by the end of the year? What I'm wondering is why we shouldn't just use the average of maybe 1999, 2000, and 2001, or maybe just 2000 and 2001, instead of -- if we are even considering adding bonuses and why we would even look at numbers from 2002 when they're not actuals?
MR. PEARCE: I think this is really Ms. Mulkern's area again. Probably she should address it.
MR. HOBERG: Ms. Mulkern, come back up again.
COMMISSIONER CLARK: We want you to sing Stairway to Heaven this time.
MS. MULKERN: We used an average of 2002, 2001 and 2000 because when we were preparing this case in March of 2002, the bonuses are generally paid out in February of each year. So when we prepared this case in March, we had the actual amount of bonuses that had been paid for 2002.
COMMISSIONER WEFALD: Okay. Thank you. That answers that question.
MR. HOBERG: Any additional questions of

Mr. Spratt? Thank you, Mr. Spratt. Is there anything else to bring to the attention of the Commission in regard to evidence in this matter? Mr. Pearce?
MR. PEARCE: Just, I guess, in the way of a general statement. There has been a lot of discussion on the depreciation study that's currently underway and, of course, it's our position that that may or may not have some effect in the future on rates, but really isn't critical for this case because we are operating now under a Commission-approved depreciation study from 1991 that we think is the appropriate one to be used. So that ongoing depreciation study certainly isn't critical. Now, it may or may not have any effect on rates in the future.
Also, I think it's appropriate to renew our motion. It's been taken under advisement, I think, that this proceeding is not the proper one to implement FAS 143 for ratemaking purposes.
MR. HOBERG: That's been taken under advisement, yes. Are you going to be providing the late-filed exhibits shortly?
MR. PEARCE: What sort of time frame? I think those can be done rather quickly.

MR. HOBERG: Probably within the next 15 days?
MR. PEARCE: Certainly, I would think. Even 10 or 15. Fifteen is fine.
MR. HOBERG: That would be appropriate, I believe. There's been some discussion about how to close this out and it's my understanding that both of the -- the staff and you want to file proposed findings of fact, conclusions of law and post hearing briefs?
MR. PEARCE: Yes.
MR. HOBERG: Mr. Binek; is that correct?
MR BINEK: Yes.
MR. HOBERG: Okay. We can do that within 30 days; is that correct?
MR. BINEK: When will the transcript be prepared?
MR. HOBERG: Are we preparing a transcript?
MR. PEARCE: Yes. And I think we should go off the record because the reporter indicated to me she prefers not to be pushed on the record as to the time.
MR. HOBERG: Let's go off the record.
(Discussion off the record.)
MR. HOBERG: Let's go back on the record.

MR. PEARCE: Maybe something like -- talking about the last week of October then, maybe.
MR. HOBERG: The Commission has until the 12th of December to issue a decision.
MR. BINEK: I was going to suggest possibly November 15 as a date for proposed findings and briefs.
MR. PEARCE: That's fine. Sure.
MR. HOBERG: That would give the Commission 30 days.
MR. BINEK: Just about 30 days.
MR. HOBERG: Okay. So you have them to the Commission by the 15th, not mailed or anything, to them by the 15th.
MR. PEARCE: Right, in their hands.
MR. BINEK: I can get them in their hands.
MR. HOBERG: You can do that.
MR. PEARCE: We have messengers. I can do that, too.
MR. HOBERG: Okay. So proposed findings of fact, conclusion of law and briefs to the Commission by November 15. Late-filed exhibits within 15 days. Is there anything else that needs attention at this time? Mr. Pearce?
MR. PEARCE: Nothing for me.

MR. HOBERG: Mr. Binek?
MR. BINEK: No.
MR. HOBERG: Thank you. Commissioner Wefald, did you have any closing statements to make?
COMMISSIONER WEFALD: Thank you for a good hearing.
MR. HOBERG: Thank you. Commissioner Clark?
COMMISSIONER CLARK: Thank you.
MR. HOBERG: Let's close this hearing. It's approximately 5:30.
(Concluded at 5:30 p.m., the same day.)

CERTIFICATE OF COURT REPORTER

I, Linda L. Gingery, a Registered Professional Reporter,
DO HEREBY CERTIFY that I recorded in shorthand the foregoing proceedings had and made of record at the time and place hereinbefore indicated.
I DO HEREBY FURTHER CERTIFY that the foregoing typewritten pages contain an accurate transcript of my shorthand notes then and there taken.
Dated at Bismarck, North Dakota, this 21st day of October, 2002.

Linda L. Gingery
Registered Professional Reporter

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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE (SMALL METERS)
ZONE 1

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	20	$78.38	$78.48	$0.10	0.13%
February	14	57.49	58.45	0.96	1.67%
March	14	57.49	58.45	0.96	1.67%
April	9	40.08	41.75	1.67	4.17%
May	6	29.64	31.73	2.09	7.05%
June	3	18.30	21.72	3.42	18.69%
July	2	14.36	18.38	4.02	27.99%
August	2	14.36	18.38	4.02	27.99%
September	4	22.23	25.06	2.83	12.73%
October	8	36.60	38.41	1.81	4.95%
November	12	50.53	51.77	1.24	2.45%
December	16	64.45	65.12	0.67	1.04%
Total	110	$483.91	$507.70	$23.79	4.92%
Base Rate @ % of Total		16%	28%		
Non- Gas Commodity		$84.71	$47.53	($37.18)	-44%

PRESENT RATE 60: 1/		PROPOSED RATE 60: 2/	
Base Rate	$6.50	Basic Delivery Charge	$11.70
1st 5 dk	$3.932	Distribution Delivery	$0.432
Over 5 dk	3.481	Cost of Gas	$2.907

1/ Rate effective March 1, 2002.
2/ Includes March 2002 Cost of Gas based on .45% loss factor plus surcharge & margin sharing.

MDU Gas Utility-ND Rate 60 Bill Comparison Residential Gas Service by Public Service Commission
Exhibit # 37
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Bond Yields of Mr. King's Proxy Group and MDU Resources/Montana-Dakota Bonds

	S&P	Moody's
AGL Resources	A-	A3
Atmos Energy Corp.	A-	A3
Cascade Natural Gas	BBB+	Baa1
Laclede Group, Inc.	A+	A3
NICOR, Inc.	AA	Aa1
Northwest Natural Gas Co.	A	A2
People's Energy Corp.	AA-	Aa2
Piedmont Natural Gas Co.	A	A2
South Jersey Industries, Inc.	A	Baa1
Southwest Gas	BBB-	Baa2
WGL Holdings	AA-	Aa2
Average/Median	**A**	**A2**
Excluding WGL Holdings	**A**	**A2/A3**
MDU Resources/Montana-Dakota Utilities Bonds	**A+**	**A2**

Source: C.A. Turner Utility Reports, September 2002.

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Bond Yields of Mr. King's Proxy Group &
MDU Resources/MDU Bonds
by Public Service Commission
Exhibit # 36
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- Natural Gas New Homes
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- Energy Mgmt. Solutions
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- Converting to Gas
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- Property Managers
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- Deregulation
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For Our Partners
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Natural Gas Furnaces

Gas heating is preferred 4 to 1 over electric

It is probably no surprise that the largest part of your energy bill comes from heating your home. But what you may not realize is that you can save up to 40% on your utility bills by converting to a high efficiency natural gas heating system. Whether you have forced-air, baseboards or radiators, natural gas has a system for you.

Things to Consider When Working with Your Contractor:

- Decide what type of natural gas system is best for your home. Your choices include hydronic heating, a forced air system, and combo-heaters.
- Determine the appropriate size unit your home requires.
- Determine the appropriate venting option.
- Compare purchase price and operating costs of different systems.
- Compare warranties on both the equipment and the installation.
- Look for design-certified models that are tested to national standards by a nationally recognized laboratory.

Email or call 703-941-HEAT or toll-free 888-941-HEAT, Monday through Friday, 8am to 8pm, for more information. You also can obtain the name of a Washington Gas-approved trade associate (heating and

Visit Washington Gas

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plumbing contractors) to get a free estimate on converting to natural gas.

For a fact sheet from the American Gas Association on natural gas heating systems, click here.

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Washington Gas | New Natural Gas Homes for Builders

Washington Gas | New Natural Gas Homes for Home Buyers

10/8/02

Why Natural Gas?

Why Natural Gas?

Natural Gas Helps Make Your New House a Home.

Lots of things make the four walls of a house into a home for your family. Time. Memories. Special events. And, right from day one, the warm, comfortable feeling you get from natural gas heating and fireplaces. Plus, you can enjoy all of the benefits of natural gas today, and take comfort in knowing you'll have a home that future homebuyers will prefer.

It's The Peoples Choice.

Natural gas is the overwhelming fuel of choice for homes throughout the Washington area because it simply works better. It's no wonder that 9 out of 10 new homes in the metropolitan area are heated with natural gas.

Gas Cooking is Preferred **2 to 1**	Gas Water Heating is Preferred **3 to 1**	Gas Heating is Preferred **4 to 1**

For The Comfort and Convenience.

Once people experience the comfort and convenience of natural gas in their homes, they prefer it over other energy sources. For example, cooking is easier on a natural gas range because temperature control is instant and precise. Natural gas fireplaces light with the flick of a switch. Clothes spun in a natural gas dryer come out fluffier and softer. Natural gas barbecues never run out of fuel.

Discover the real benefits of natural gas for:

Heating Your Home

Relaxing By The Fireplace

Heating Your Water

Cooking Your Food

Drying Your Clothes

Enjoying The Outdoors

It's Your Best Energy Value.

Natural gas is energy-efficient, clean-burning and dependable. It's a natural source of energy, unlike electricity, which has to be created using another form of energy. And because natural gas burns clean, there's less pollution. That's better for you and the environment.

Find A New Home | Why Natural Gas? | Natural Gas Dream House | FAQs | Home
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Washington Gas | New Natural Gas Homes for Builders

Washington Gas | New Natural Gas Homes for Home Buyers

10/8/02

Why Natural Gas?

Natural Gas Heating System

Heating Your Home

NATURAL GAS HEATING SYSTEMS

- 9 out of 10 new homes in the metropolitan area are heated with natural gas.
- Keep your family comfortable with warm air, hot water or steam.

Want to try to squeeze a little warmth out of a heat pump?

An electric heat pump just can't warm you like a natural gas heating system can. That's because regardless of the temperature outside, a heat pump blows cold air. And cold air never helped anyone stay warm.

High-efficiency natural gas heating systems keep you warm and comfortable on the chilliest days. It's the heating system most people choose, because it works.

A home's heating system can be the largest energy user, so it's important to have an efficient, economical and reliable system. That's why natural gas heating systems are preferred 4 to 1 over electric heat pumps. They're up to 97 percent efficient and can save you up to 40 percent on utility bills compared to some older models.

More Natural Gas Options

©2001, Washington Gas New Natural Gas Homes

Ibbotson Historical Returns

	Large Co. Stocks	Small Co Stocks	Long Term Corp.Bonds	Long Term Gov. Bonds	Large Co. Stocks Minus: Long Term Corp.Bonds	Large Co. Stocks Minus: Long Term Gov. Bonds
1926	11.62%	0.28%	7.37%	7.77%	4.25%	3.85%
1927	37.49%	22.10%	7.44%	8.93%	30.05%	28.56%
1928	43.61%	39.69%	2.84%	0.10%	40.77%	43.51%
1929	-8.42%	-51.36%	3.27%	3.42%	-11.69%	-11.84%
1930	24.90%	-38.15%	7.98%	4.66%	16.92%	20.24%
1931	-43.34%	-49.75%	-1.85%	-5.31%	-41.49%	-38.03%
1932	-8.19%	-5.39%	10.82%	16.84%	-19.01%	-25.03%
1933	53.99%	142.87%	10.38%	-0.07%	43.61%	54.06%
1934	1.44%	24.22%	13.84%	10.03%	-12.40%	-8.59%
1935	47.67%	40.19%	9.61%	4.98%	38.06%	42.69%
1936	33.02%	64.80%	6.74%	7.52%	26.28%	25.50%
1937	-35.03%	-58.01%	2.75%	0.23%	-37.78%	-35.26%
1938	31.13%	32.80%	6.13%	5.53%	25.00%	25.60%
1939	0.41%	0.35%	3.97%	5.94%	-3.56%	-5.53%
1940	9.78%	-5.16%	3.39%	6.09%	6.39%	3.69%
1941	-11.59%	-9.00%	2.73%	0.93%	-14.32%	-12.52%
1942	20.34%	44.51%	2.60%	3.22%	17.74%	17.12%
1943	25.90%	88.37%	2.83%	2.08%	23.07%	23.82%
1944	19.75%	53.72%	4.73%	2.81%	15.02%	16.94%
1945	36.44%	73.61%	4.08%	10.73%	32.36%	25.71%
1946	8.07%	-11.63%	1.72%	-0.10%	6.35%	8.17%
1947	5.71%	0.92%	-2.34%	-2.62%	8.05%	8.33%
1948	5.50%	-2.11%	4.14%	3.40%	1.36%	2.10%
1949	18.69%	19.75%	3.31%	6.45%	15.38%	12.24%
1950	31.71%	38.75%	2.12%	0.06%	29.59%	31.65%
1951	24.02%	7.80%	-2.69%	-3.93%	26.71%	27.95%
1952	18.37%	3.03%	3.52%	1.16%	14.85%	17.21%
1953	-0.99%	-6.49%	3.41%	3.64%	-4.40%	-4.63%
1954	52.62%	60.58%	5.39%	7.19%	47.23%	45.43%
1955	31.56%	20.44%	0.48%	-1.29%	31.08%	32.85%
1956	6.56%	4.28%	-6.81%	-5.59%	13.37%	12.15%
1957	-10.78%	-14.57%	8.71%	7.46%	-19.49%	-18.24%
1958	43.36%	64.89%	-2.22%	-6.09%	45.58%	49.45%
1959	11.96%	16.40%	-0.97%	-2.26%	12.93%	14.22%
1960	0.47%	-3.29%	9.07%	13.78%	-8.60%	-13.31%
1961	26.89%	32.09%	4.82%	0.97%	22.07%	25.92%
1962	-8.73%	-11.90%	7.95%	6.89%	-16.68%	-15.62%
1963	22.80%	23.57%	2.19%	1.21%	20.61%	21.59%
1964	16.48%	23.52%	4.77%	3.51%	11.71%	12.97%
1965	12.45%	41.75%	-0.46%	0.71%	12.91%	11.74%
1966	-10.06%	-7.01%	0.20%	3.65%	-10.26%	-13.71%
1967	23.98%	83.57%	-4.95%	-9.18%	28.93%	33.16%
1968	11.06%	35.97%	2.57%	-0.26%	8.49%	11.32%

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1969	-8.50%	-25.05%	-8.09%	-5.07%	-0.41%	-3.43%
1970	4.01%	-17.43%	18.37%	12.11%	-14.36%	-8.10%
1971	14.31%	16.50%	11.01%	13.23%	3.30%	1.08%
1972	18.98%	4.43%	7.26%	5.69%	11.72%	13.29%
1973	-14.66%	-30.90%	1.14%	-1.11%	-15.80%	-13.55%
1974	-26.47%	-19.95%	-3.06%	4.35%	-23.41%	-30.82%
1975	37.20%	52.82%	14.64%	9.20%	22.56%	28.00%
1976	23.84%	57.38%	18.65%	16.75%	5.19%	7.09%
1977	-7.18%	25.38%	1.71%	-0.69%	-8.89%	-6.49%
1978	6.56%	23.46%	-0.07%	-1.18%	6.63%	7.74%
1979	18.44%	43.46%	-4.18%	-1.23%	22.62%	19.67%
1980	32.42%	39.88%	-2.76%	-3.95%	35.18%	36.37%
1981	-4.91%	13.88%	-1.24%	1.86%	-3.67%	-6.77%
1982	21.41%	28.01%	42.56%	40.36%	-21.15%	-18.95%
1983	22.51%	39.67%	6.26%	0.65%	16.25%	21.86%
1984	6.27%	-6.67%	16.86%	15.48%	-10.59%	-9.21%
1985	32.16%	24.66%	30.09%	30.97%	2.07%	1.19%
1986	18.47%	6.85%	19.85%	24.53%	-1.38%	-6.06%
1987	5.23%	-9.30%	-0.27%	-2.71%	5.50%	7.94%
1988	16.81%	22.87%	10.70%	9.67%	6.11%	7.14%
1989	31.49%	10.18%	16.23%	18.11%	15.26%	13.38%
1990	-3.17%	-21.56%	6.78%	6.18%	-9.95%	-9.35%
1991	30.55%	44.63%	19.89%	19.30%	10.66%	11.25%
1992	7.67%	23.35%	9.39%	8.05%	-1.72%	-0.38%
1993	9.99%	20.98%	13.19%	18.24%	-3.20%	-8.25%
1994	1.31%	3.11%	-5.76%	-7.77%	7.07%	9.08%
1995	37.43%	34.46%	27.20%	31.67%	10.23%	5.76%
1996	23.07%	17.62%	1.40%	-0.93%	21.67%	24.00%
1997	33.36%	22.78%	12.95%	15.85%	20.41%	17.51%
1998	28.58%	-7.31%	10.76%	13.06%	17.82%	15.52%
1999	21.04%	29.79%	-7.45%	-8.96%	28.49%	30.00%
2000	-9.11%	-3.59%	12.87%	21.48%	-21.98%	-30.59%
2001	-11.88%	22.77%	10.65%	3.70%	-22.53%	-15.58%
Average	13.81%	17.34%	6.09%	5.69%	7.72%	8.13%
Std. Dev.	19.43%	33.23%	8.65%	9.36%	19.33%	20.19%

t-Test:
Two-Sample Assuming Unequal Variances

	Large Co. Stocks	*Long Term Gov. Bonds*
Mean	13.81%	5.69%
Variance	3.78%	0.88%
Observatior	76	76
Hypothesize	**0**	
df	108	
t Stat	3.285422	
P(T<=t) one	**0.07%**	
t Critical on	1.659087	
P(T<=t) two	0.14%	
t Critical tw	1.982171	

t-Test:
Two-Sample Assuming Unequal Variances

	Large Co. Stocks	*Long Term Corp.Bonds*
Mean	13.81%	6.13%
Variance	3.78%	0.73%
Observations	76	78
Hypothesized Mean	**0**	
df	102	
t Stat	3.164077	
P(T<=t) one-tail	**0.10%**	
t Critical one-tail	1.65993	
P(T<=t) two-tail	0.21%	
t Critical two-tail	1.983494	

t-Test:
Two-Sample Assuming Unequal

	Large Co. Stocks	*Long Term Gov. Bonds*
Mean	13.81%	5.69%
Variance	3.78%	0.88%
Observatior	76	76
Hypothesize	**8.13%**	
df	108	
t Stat	-0.000585	
P(T<=t) one	**49.98%**	
t Critical on	1.659087	
P(T<=t) two	99.95%	
t Critical tw	1.982171	

t-Test:
Two-Sample Assuming Unequal Variances

	Large Co. Stocks	*Long Term Corp.Bonds*
Mean	13.81%	6.13%
Variance	3.78%	0.73%
Observations	76	78
Hypothesized Mean	**7.72%**	
df	102	
t Stat	-0.001014	
P(T<=t) one-tail	**49.96%**	
t Critical one-tail	1.65993	
P(T<=t) two-tail	99.92%	
t Critical two-tail	1.983494	

Summary of DCF Studies

	Average Results of DCF Studies	Flotation Cost Factor	Cost of Capital
Dr. Gaske Studies			
Second-Stage Retention Growth	12.83%	1.0475	13.44%
Basic	12.95%	1.0475	13.57%
Primary	12.63%	1.0475	13.23%
Excluding KeySpan & Laclede			
Second-Stage Retention Growth	11.75%	1.0475	12.31%
Basic	11.51%	1.0475	12.06%
Dr. Gaske's Calculation Using Mr. King's Proxy Selection Criteria & Growth Data			
2/3 Zack's and 1/3 Book Value	11.80%	1.0475	12.36%
50% Zack's and 50% Book Value	12.00%	1.0475	12.57%
King's Studies			
Book Value	12.18%	1.0475	12.76%
Historical	11.72%	1.0475	12.28%
Classic	11.29%	1.0475	11.83%
Classic Adjusted by Mr. King to Also Reflect Book Value and Historical	11.23%	1.0475	11.76%

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Summary of DCF Studies

by Public Service Commission

Exhibit # 33

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Alternative Proxy Groups

	% Gas Distribution	Moody's Gas Distribution Group
Cascade Natural Gas	100.0%	
Piedmont Natural Gas Co.	100.0%	
South Jersey Industries, Inc.	100.0%	
Northwest Natural Gas Co.	97.8%	X
Atmos Energy Corp.	95.6%	
Laclede Group, Inc.	92.8%	X
AGL Resources	87.1%	X
Southwest Gas	85.4%	
NICOR, Inc.	83.4%	
People's Energy Corp.	80.8%	X
WGL Holdings	74.6%	X
KeySpan	54.5%	X

Average/Median

MDU Resources/Montana-Dakota Utilities Bonds

Sources:
~~Bond Ratings: C.A. Turner Utility Reports, September 2002.~~
% Gas Distribution: Direct Testimony of Charles W. King, Table 11, page 25.

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Effects of A Flotation Cost Adjustment

Dilution in Value Without A Flotation Cost Adjustment

	Book Value	Market Value = BV	Shares	Per Share Book	Per Share Market	Rate of Return = 15%	$ of Return
Existing Equity	100	100	100	**$ 1.00**	**$ 1.00**	**15.00%**	$ 15.00
New Issue Invested in Public Utility Plant	90	90	100			15.00%	$ 13.50
Total Rate Base	190	190	200	**$ 0.95**	**$ 0.95**		$ 28.50
Flotation Cost	10	10				0.00%	$ -
Total Equity Investment	200	200				**14.25%**	$ 28.50

Flotation Cost Adjustment Enables Stock Issuance With No Dilution

	Book Value	Market Value = 1.1 * BV	Shares	Per Share Book	Per Share Market	Rate of Return = 15% * 1.1	$ of Return
Existing Equity	100	110	100	**$ 1.00**	**$ 1.10**	**16.50%**	$ 16.50
New Issue Invested in Public Utility Plant	100	110	100			16.50%	$ 16.50
Total Rate Base	200	220	200	**$ 1.00**	**$ 1.10**		$ 33.00
Flotation Cost	10					0.00%	$ -
Total Equity Investment	210					**15.71%**	$ 33.00

Large Stock Issuance Results

	Book Value	Market Value = 1.1 * BV	Shares	Per Share Book	Per Share Market	Rate of Return = 15% * 1.1	$ of Return
Existing Equity	$ 100	$ 110	100	**$ 1.00**	**$ 1.10**	**16.50%**	$ 16.50
New Issue Invested in Public Utility Plant	$ 10,000	$ 11,000	10,000			16.50%	$1,650.00
Total Rate Base	$ 10,100	$ 11,110	10,100	**$ 1.00**	**$ 1.10**		$1,666.50
Flotation Cost	$ 1,000					0.00%	$ -
Total Equity Investment	$ 11,100					**15.01%**	$1,666.50

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Effects of a Flotatopm Cost Adjustment

by Public Service Commission
Exhibit # 31
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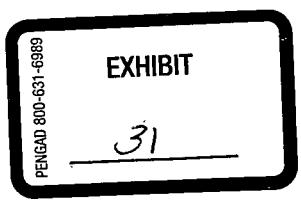

Montana-Dakota Utilities Company
Summary of Negative Salvage for Services 1995-2001
Taken from Company summaries with one month detail each year.

Year	Cummulative	Annual	Memo-Jan
1995	141,907.01	141,907.01	3,107.88
1996	338,577.59	196,670.58	1,271.31
1997	506,894.59	168,317.00	1,363.44
1998	739,740.07	232,845.48	1,469.29
1999	946,119.07	206,379.00	2,207.97
2000	1,156,580.61	210,461.54	1,766.15
2001	1,387,946.12	231,365.51	3,725.88
		1,387,946.12	14,911.92

Jan-95	Jan-96	Jan-97	Jan-98	Jan-99	Jan-00	Jan-01
703.13	147.75	20.89	1.11	6.94	153.98	532.94
128.50	4.12	50.58	220.00	80.55	90.90	58.28
810.73	6.78	2.79	50.00	563.62	126.90	7.44
89.65	15.01	15.63	44.00	57.60	104.91	240.97
963.75	43.10	168.04	258.01	383.97	32.55	6.50
4.48	86.19	15.63	64.85	275.52	414.40	70.00
4.48	850.89	31.26	14.00	14.00	124.15	299.03
9.00	42.92	121.21	20.00	195.32	8.58	250.43
19.43	21.80	15.63	51.29	163.20	167.60	84.21
312.50	2.09	276.81	225.00	188.54	6.19	1.46
19.84	21.04	183.40	26.00	278.71	190.91	65.85
37.39	2.09	213.67	55.03		11.00	9.78
5.00	25.00	31.26	220.00		334.08	1,862.28
	2.53	216.64	220.00			236.71
3,107.88	1,271.31	1,363.44	1,469.29	2,207.97	1,766.15	3,725.88

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EXHIBIT 30

09200 Account Ledger Inquiry

Account. 1.1082.380RC
Services-Removal Cost

Ship to Doc/Type .
Y-D Period End . 141,907.01
Cumul Period End . 141,907.01

From Date/Period 01/01/95
Thru Date/Period 12/31/95
Ledger Type. . . AA
Subledger. . . . *

O	DT	Document	Date	Explanation	Debit	Credit	P
_	JE	17606	01/31/95	Clear Acct 1082	703.13		P
_	JE	17606	01/31/95	Clear Acct 1082		12.06-	P
_	JE	17606	01/31/95	Clear Acct 1082	128.50		P
_	JE	17606	01/31/95	Clear Acct 1082	810.73		P
_	JE	17606	01/31/95	Clear Acct 1082	89.65		P
_	JE	17606	01/31/95	Clear Acct 1082	963.75		P
_	JE	17606	01/31/95	Clear Acct 1082	4.48		P
_	JE	17606	01/31/95	Clear Acct 1082	4.48		P
_	JE	17606	01/31/95	Clear Acct 1082	9.00		P
_	JE	17606	01/31/95	Clear Acct 1082	19.43		P
_	JE	17606	01/31/95	Clear Acct 1082	312.50		P
_	JE	17606	01/31/95	Clear Acct 1082	19.84		P
_	JE	17606	01/31/95	Clear Acct 1082	37.39		P
_	JE	17606	01/31/95	Clear Acct 1082	5.00		P

Opt: 1/2=Orig Entry 5=Details F21=Prt Ledg F17=Top F18=Totals F24=More

09200 Account Ledger Inquiry

Account. 1.1082.380RC
Services-Removal Cost

Skip to Doc/Type .
Y-T-D Period End . 196,670.58
Cumul Period End . 338,577.59

From Date/Period 01/01/96
Thru Date/Period 12/31/96
Ledger Type. . . AA
Subledger. . . . *

O	DT	Document	Date	Explanation	Debit	Credit	P
_	AD	200316	01/31/96	Blanket retire clo	147.75		P
_	AD	200316	01/31/96	Blanket retire clo	4.12		P
_	AD	200316	01/31/96	Blanket retire clo	6.78		P
_	AD	200316	01/31/96	Blanket retire clo	15.01		P
_	AD	200286	01/31/96	Blanket retire clo	43.10		P
_	AD	200286	01/31/96	Blanket retire clo	86.19		P
_	AD	200286	01/31/96	Blanket retire clo	850.89		P
_	AD	200286	01/31/96	Blanket retire clo	42.92		P
_	AD	199778	01/31/96	JAN. 96, RETIREMEN	21.80		P
_	AD	199900	01/31/96	Blanket retire sta	2.09		P
_	AD	199778	01/31/96	JAN. 96, RETIREMEN	21.04		P
_	AD	199900	01/31/96	Blanket retire sta	2.09		P
_	AD	199742	01/31/96	JAN. 96, RETIREMEN	25.00		P
_	AD	200316	01/31/96	Blanket retire clo	2.53		P

Opt: 1/2=Orig Entry 5=Details F21=Prt Ledg F17=Top F18=Totals F24=More

09200 **Account Ledger Inquiry**

Account. 1.1082.380RC
Services-Removal Cost

From Date/Period 01/01/97
Thru Date/Period 12/31/97
Ledger Type. . . AA
Subledger. . . . *

Ship to Doc/Type .
Y-D Period End . 168,317.00
Cumul Period End . 506,894.59

O	DT	Document	Date	Explanation	Debit	Credit	P
_	AD	256416	01/31/97	Dec 96 Dkn-WP Gas	20.89		P
_	AD	256412	01/31/97	Dec 96 Blgs-BH Gas	50.58		P
_	AD	256412	01/31/97	Dec 96 Blgs-BH Gas	2.79		P
_	AD	256983	01/31/97	Dec 96 Specific Ga	15.63		P
_	AD	256416	01/31/97	Dec 96 Dkn-WP Gas	168.04		P
_	AD	256983	01/31/97	Dec 96 Specific Ga	15.63		P
_	AD	256983	01/31/97	Dec 96 Specific Ga	31.26		P
_	AD	256412	01/31/97	Dec 96 Blgs-BH Gas	121.21		P
_	AD	256983	01/31/97	Dec 96 Specific Ga	15.63		P
_	AD	256416	01/31/97	Dec 96 Dkn-WP Gas	276.81		P
_	AD	256416	01/31/97	Dec 96 Dkn-WP Gas	183.40		P
_	AD	256412	01/31/97	Dec 96 Blgs-BH Gas	213.67		P
_	AD	256983	01/31/97	Dec 96 Specific Ga	31.26		P
_	AD	256416	01/31/97	Dec 96 Dkn-WP Gas	216.64		P

Opt: 1/2=Orig Entry 5=Details F21=Prt Ledg F17=Top F18=Totals F24=More

09200 Account Ledger Inquiry

Account. 1.1082.380RC
Services-Removal Cost

From Date/Period 01/01/98
Thru Date/Period 12/31/98
Ledger Type. . . AA
Subledger. . . . *

Skip to Doc/Type .
Y-T-D Period End . 232,845.48
Cumul Period End . 739,740.07

O	DT	Document	Date	Explanation	Debit	Credit	P
_	AD	312344	01/31/98	GAS RETIREMENTS	1.11		P
_	AD	312344	01/31/98	GAS RETIREMENTS	220.00		P
_	AD	312344	01/31/98	GAS RETIREMENTS	50.00		P
_	AD	312344	01/31/98	GAS RETIREMENTS	44.00		P
_	AD	314304	01/31/98	GAS RETIREMENTS	258.01		P
_	AD	312344	01/31/98	GAS RETIREMENTS	64.85		P
_	AD	312344	01/31/98	GAS RETIREMENTS	14.00		P
_	AD	312344	01/31/98	GAS RETIREMENTS	20.00		P
_	AD	312344	01/31/98	GAS RETIREMENTS	51.29		P
_	AD	312344	01/31/98	GAS RETIREMENTS	225.00		P
_	AD	312344	01/31/98	GAS RETIREMENTS	26.00		P
_	AD	312344	01/31/98	GAS RETIREMENTS	55.03		P
_	AD	312344	01/31/98	GAS RETIREMENTS	220.00		P
_	AD	312344	01/31/98	GAS RETIREMENTS	220.00		P

Opt: 1/2=Orig Entry 5=Details F21=Prt Ledg F17=Top F18=Totals F24=More

09200 **Account Ledger Inquiry**

Account. 1.1082.380RC
Services-Removal Cost
Skip to Doc/Type .
Y-D Period End . 206,379.00
Cumul Period End . 946,119.07

From Date/Period 01/01/99
Thru Date/Period 12/31/99
Ledger Type. . . AA
Subledger. . . . *

O	DT	Document	Date	Explanation	Debit	Credit	P
_	AD	372862	01/31/99	GAS BLANKETS RETIR		.57-	P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	6.94		P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	80.55		P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	563.62		P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	57.60		P
_	AD	372750	01/31/99	FAIRVIEW ND,MT ASS	383.97		P
_	AD	372750	01/31/99	FAIRVIEW ND,MT ASS		383.97-	P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	275.52		P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	14.00		P
_	AD	372750	01/31/99	FAIRVIEW ND,MT ASS	195.32		P
_	AD	372750	01/31/99	FAIRVIEW ND,MT ASS		195.32-	P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	163.20		P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	188.54		P
_	AD	372862	01/31/99	GAS BLANKETS RETIR	278.71		P

Opt: 1/2=Orig Entry 5=Details F21=Prt Ledg F17=Top F18=Totals F24=More

09200 **Account Ledger Inquiry**

Account. 1.1082.380RC
Services-Removal Cost

From Date/Period 01/01/00
Thru Date/Period 12/31/00
Ledger Type. . . AA
Subledger. . . . *

Skip to Doc/Type .
Y-T-D Period End . 210,461.54
Cumul Period End . 1,156,580.61

O	DT	Document	Date	Explanation	Debit	Credit	P
_	AD	406826	01/31/00	GAS RETIREMENTS	153.98		P
_	AD	406826	01/31/00	GAS RETIREMENTS	90.90		P
_	AD	406826	01/31/00	GAS RETIREMENTS	126.90		P
_	AD	406826	01/31/00	GAS RETIREMENTS	104.91		P
_	AD	401827	01/31/00	GAS RETIREMENTS	32.55		P
_	AD	406826	01/31/00	GAS RETIREMENTS	414.40		P
_	AD	401827	01/31/00	GAS RETIREMENTS		7.70-	P
_	AD	406819	01/31/00	GAS RETIREMENTS	124.15		P
_	AD	401827	01/31/00	GAS RETIREMENTS	8.58		P
_	AD	406819	01/31/00	GAS RETIREMENTS	167.60		P
_	AD	401827	01/31/00	GAS RETIREMENTS	6.19		P
_	AD	406826	01/31/00	GAS RETIREMENTS	190.91		P
_	AD	406826	01/31/00	GAS RETIREMENTS	11.00		P
_	AD	406826	01/31/00	GAS RETIREMENTS	334.08		P

Opt: 1/2=Orig Entry 5=Details F21=Prt Ledg F17=Top F18=Totals F24=More

09200 **Account Ledger Inquiry**

Account. 1.1082.380RC
Services-Removal Cost
Skip to Doc/Type . _____ __
Y-D Period End . 231,365.51
Cumul Period End . 1,387,946.12

From Date/Period 01/01/01
Thru Date/Period 12/31/01
Ledger Type. . . AA
Subledger. . . . *

O	DT	Document	Date	Explanation	Debit	Credit	P
_	AD	504622	01/31/01	GAS RETIREMENTS	532.94		P
_	AD	504622	01/31/01	GAS RETIREMENTS	58.28		P
_	AD	504622	01/31/01	GAS RETIREMENTS	7.44		P
_	AD	504622	01/31/01	GAS RETIREMENTS	240.97		P
_	AD	504622	01/31/01	GAS RETIREMENTS	6.50		P
_	AD	504622	01/31/01	GAS RETIREMENTS	70.00		P
_	AD	504622	01/31/01	GAS RETIREMENTS	299.03		P
_	AD	504622	01/31/01	GAS RETIREMENTS	250.43		P
_	AD	504622	01/31/01	GAS RETIREMENTS	84.21		P
_	AD	504622	01/31/01	GAS RETIREMENTS	1.46		P
_	AD	504622	01/31/01	GAS RETIREMENTS	65.85		P
_	AD	504622	01/31/01	GAS RETIREMENTS	9.78		P
_	AD	504622	01/31/01	GAS RETIREMENTS	1,862.28		P
_	AD	504622	01/31/01	GAS RETIREMENTS	236.71		P

Opt: 1/2=Orig Entry 5=Details F21=Prt Ledg F17=Top F18=Totals F24=More

Montana-Dakota Utilities Company
Summary of Exhibit___(MJM-7)
Amounts in thousands

	12 Months Ended Dec. 31, 2001	Projected Year 2003			
		Majoros Recommended			
	Average Plant	Annual Depreciation	Annual Depreciation	Annual Salvage	Net Depreciation
	(a) Exh. MJM-7 Page 2 of 3	(b) Exh. MJM-7 Page 2 of 3	(c) Exh. MJM-7 Page 3 of 3	(d) Note 1.	(e)
Distribution	$ 54,507	$ 1,291	$ 1,378	-	
General	6,832	330	111		
	61,338	1,621	1,489	289	1,200
Common, including intangibles-Note 2.	7,150	451	440	559	(119)
Subtotal	68,489	2,073	1,929	848	1,081
Amortization, other	299	7	8	-	8
	68,787	2,080	1,937	848	1,089

Notes:

1. The salvage amounts are from Exhibit___(MJM-6) and were allocated as follows:

Natural gas salvage equals $1,444,452 thousand divided by 5 years	$288.890
Common plant salvage equals $2,795.6 thousand divided by 5 years	559.120
Total	848.010

2. The Common plant and depreciation amounts were summarized as follows:

	Plant	2001 Deprec.	2003 Deprec.
Total common less intangible	5381.300	270.831	211.000
Common intangible	1768.983	180.613	229.000
	7150.283	451.444	440.000

PENGAD 800-631-6989
EXHIBIT
29

MONTANA-DAKOTA UTILITIES CO.
FIRST DATA REQUESTS
CHARLES KING ON BEHALF OF THE NORTH DAKOTA
PUBLIC SERVICE COMMISSION STAFF
DATED JULY 25, 2002
CASE NO. PU-399-02-183

Request No. 21 Reference: Statements A-F, G-L, N-O.

Please provide annual North Dakota gas utility gross salvage and cost of removal by plant account beginning 1986 through 2003.

Response:

Please see Attachment A. For the years 1986 through 1994, the information is available for the total company only. The years 1995 through 2001 show both total company and as allocated to North Dakota. Please see Statement O, pages 5 and 6 for the salvage and removal costs for projected 2002 and 2003.

C King data request no. 21

by Public Service Commission
Exhibit # 21
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

PENGAD 800-631-6989 **EXHIBIT** 21

ATTACHMENT A

MONTANA-DAKOTA UTILITIES CO. GE 005
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS PROCESSED 01 13 87
GAS PLANT IN SERVICE

RIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	185.55-	.00	22,369.81-
.00	.00	.00	.00	2,226.60-	.00	22,369.81-
.00	.00	.00	.00	809.94-	.00	162,259.55-
1,006.41	781.10	620.46	.00	9,719.28-	634.41-	162,259.55-
.00	.00	.00	.00	157,780.41-	.00	20,279,281.70-
164,397.14	51,009.31	401.47	1,935.61-	1824,143.46-	.00	20,279,281.70-
.00	.00	.00	.00	2,203.72-	.00	514,074.23-
6,028.86	1,178.98	3,133.32-	.00	26,444.64-	.00	514,074.23-
.00	.00	.00	.00	171.91-	.00	211,008.86-
.00	.00	.00	.00	2,062.92-	.00	211,008.86-
.00	.00	.00	.00	97,748.01-	.00	7,293,698.50-
82,204.03	158,249.58	6,284.69	195.92-	1137,382.46-	.00	7,293,698.50-
.00	.00	.00	.00	39,560.27-	.00	4,640,888.88-
120,997.42	.00	22,771.82-	.00	470,411.64-	906.03-	4,640,888.88-
.00	.00	.00	.00	4,255.97-	.00	971,261.06-
26,481.25	.00	6,050.68-	.00	50,077.79-	533.98	971,261.06-
.00	.00	.00	.00	253.49-	.00	110,542.15-
573.60	.00	227.14-	.00	3,041.88-	509.26	110,542.15-
.00	.00	.00	.00	2,963.29-	.00	144,136.20-
44,237.04	808.26	148.00-	.00	32,889.43-	.00	144,136.20-
.00	.00	.00	.00	347.30-	.00	74,226.54-
.00	.00	.00	.00	4,167.60-	.00	74,226.54-
.00	.00	.00	.00	3,815.29-	.00	905,948.68-
4,959.76	327.26	1,000.00-	.00	45,768.83-	.00	905,948.68-
.00	.00	.00	.00	1,689.27-	.00	265,881.31-
12,429.91	.00	53.50-	.00	20,271.24-	360.26-	265,881.31-
.00	.00	.00	.00	3,186.12-	.00	131,225.60-
105.47	.00	.00	.00	38,233.44-	189.00-	131,225.60-
.00	.00	.00	.00	209.26-	.00	92,275.00-
.00	.00	.00	.00	2,511.12-	.00	92,275.00-
.00	.00	.00	.00	2,583.01-	.00	524,559.65-
7,999.72	.00	834.36-	.00	39,060.52-	28,133.40	524,559.65-
.00	.00	.00	.00	1,606.12-	.00	245,582.55-
3,524.76	39.34	1,250.00-	.00	19,273.44-	.00	245,582.55-
.00	.00	.00	.00	405.31-	.00	19,824.73-
.00	.00	.00	.00	810.62-	19,014.11-	19,824.73-
.00	.00	.00	.00	266.25-	.00	43,372.08-
.00	.00	.00	.00	3,195.00-	.00	43,372.08-

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
GAS PLANT IN SERVICE

RIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	13,887.67-	.00	1,878,623.86-
43,816.13	.00	38,509.33-	.00	163,389.01-	16,625.02	1,878,623.86-
.00	.00	.00	.00	319.59-	.00	8,646.21
.00	.00	.00	.00	1,505.52-	.00	8,646.21
.00	.00	.00	.00	502.63-	.00	49,967.21-
.00	.00	.00	.00	2,630.46-	.00	49,967.21-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	94.34-	.00	76,200.93-
348.92	.00	.00	.00	1,132.08-	.00	76,200.93-
.00	.00	.00	.00	334,844.72-	.00	38,648,562.87-
519,110.42	212,393.83	66,671.53-	2,131.53-	3900,348.98-	24,697.85	38,648,562.87-
.00	.00	.00	.00	334,844.72-	.00	38,648,562.87-
519,110.42	212,393.83	66,671.53-	2,131.53-	3900,348.98-	24,697.85	38,648,562.87-

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
COMMON PLANT IN SERVICE

RIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	25,756.49-	.00	2,318,496.92-
353,205.79	23,017.27	462.87-	3,960.00-	303,798.65-	374.69	2,318,496.92-
.00	.00	.00	.00	12,926.98-	.00	1,231,998.26-
75,056.59	.00	10,944.66-	.00	154,471.53-	2,166.16	1,231,998.26-
.00	.00	.00	.00	95,557.94-	.00	2,378,203.86-
325,064.40	.00	97,873.56-	.00	963,494.57-	8,889.32	2,378,203.86-
.00	.00	.00	.00	156.20-	.00	183,098.31-
661.19	.00	.00	.00	1,874.40-	6,034.04	183,098.31-
.00	.00	.00	.00	71,605.83-	.00	4,826,174.42-
539,562.46	588.94	64,181.75-	.00	870,796.23-	5,690.87-	4,826,174.42-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	553.91-	.00	14,515.07-
.00	.00	.00	.00	1,107.72-	13,407.35-	14,515.07-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	3,675.43-	.00	338,980.85-
14,045.34	1,317.58	834.60-	.00	41,575.28-	.00	338,980.85-
.00	.00	.00	.00	3,445.92-	.00	454,897.68-
3,979.89	46.18	.00	.00	41,351.11-	.00	454,897.68-
.00	.00	.00	.00	431.60-	.00	9,164.06-
.00	.00	.00	.00	5,179.20-	.00	9,164.06-
.00	.00	.00	.00	350.06-	.00	101,584.70-
.00	.00	.00	.00	4,747.13-	.00	101,584.70-
.00	.00	.00	.00	1,969.97-	.00	100,468.20-
267.62	.00	.00	.00	23,639.56-	4,064.41	100,468.20-
.00	.00	.00	.00	216,430.33-	.00	11,957,582.33-
1311,843.28	24,969.97	174,297.44-	3,960.00-	2412,035.38-	2,430.40	11,957,582.33-
.00	.00	.00	.00	216,430.33-	.00	11,957,582.33-
1311,843.28	24,969.97	174,297.44-	3,960.00-	2412,035.38-	2,430.40	11,957,582.33-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

GAS PLANT IN SERVICE

PROCESSED 01 15 88

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	199.47-	.00	24,763.45-
.00	.00	.00	.00	2,393.64-	.00	24,763.45-
.00	.00	.00	.00	854.77-	.00	171,379.06-
891.58	83.33	.00	.00	9,402.47-	691.95-	171,379.06-
.00	.00	.00	.00	162,962.88-	.00	21,912,339.76-
201,062.80	90,443.45	231.86	7,527.67-	1916,556.06-	712.44-	21,912,339.76-
.00	.00	.00	.00	2,252.72-	.00	536,803.01-
4,864.25	608.41	1,168.80-	.00	27,032.64-	.00	536,803.01-
.00	.00	.00	.00	171.12-	.00	192,775.68-
240.01	56.84	.00	.00	2,053.44-	19,989.77	192,775.68-
.00	.00	.00	.00	101,890.77-	.00	8,203,101.93-
102,945.66	169,635.34	9,128.60	267.56-	1190,441.72-	403.75-	8,203,101.93-
.00	.00	.00	.00	39,945.84-	.00	5,026,235.87-
113,329.32	.00	19,829.78-	.00	476,755.14-	2,091.39-	5,026,235.87-
.00	.00	.00	.00	4,255.97-	.00	995,637.27-
28,723.49	836.11	3,727.71-	.00	51,071.64-	863.54	995,637.27-
.00	.00	.00	.00	308.39-	.00	129,988.22-
5,110.78	653.90	2,075.47-	.00	3,145.51-	19,989.77-	129,988.22-
.00	.00	.00	.00	3,022.05-	.00	160,863.61-
19,054.14	669.05	186.00-	.00	36,264.60-	.00	160,863.61-
.00	.00	.00	.00	347.30-	.00	77,638.65-
606.13	.00	149.36	.00	4,167.60-	.00	77,638.65-
.00	.00	.00	.00	3,810.12-	.00	923,124.55-
100,209.57	85.89	.00	71,170.25-	46,301.08-	.00	923,124.55-
.00	.00	.00	.00	1,699.20-	.00	265,790.04-
22,351.51	.00	1,869.84-	.00	20,390.40-	.00	265,790.04-
.00	.00	.00	.00	3,901.27-	.00	183,333.28-
.00	.00	.00	.00	46,815.24-	5,292.44-	183,333.28-
.00	.00	.00	.00	213.57-	.00	94,837.84-
.00	.00	.00	.00	2,562.84-	.00	94,837.84-
.00	.00	.00	.00	2,596.53-	.00	545,977.83-
3,708.89	156.17	.00	.00	31,158.36-	5,875.12	545,977.83-
.00	.00	.00	.00	1,685.16-	.00	256,503.83-
6,541.29	.00	2,872.00-	.00	20,221.92-	5,631.35	256,503.83-
.00	.00	.00	.00	405.31-	.00	24,688.45-
.00	.00	.00	.00	4,863.72-	.00	24,688.45-
.00	.00	.00	.00	266.25-	.00	48,822.41-
508.38	.00	.00	.00	4,049.77-	1,908.94-	48,822.41-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

GAS PLANT IN SERVICE

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	14,395.41-	.00	2,012,371.00-
60,103.95	211.74	21,504.91-	.00	170,719.81-	1,838.11-	2,012,371.00-
.00	.00	.00	.00	368.67-	.00	4,222.17
.00	.00	.00	.00	4,424.04-	.00	4,222.17
.00	.00	.00	.00	502.63-	.00	55,998.77-
.00	.00	.00	.00	6,031.56-	.00	55,998.77-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	94.26-	.00	76,690.01-
717.04	.00	75.00-	.00	1,131.12-	.00	76,690.01-
.00	.00	.00	.00	346,149.66-	.00	41,915,442.35-
670,968.79	263,440.23	43,799.69-	78,965.48-	4077,954.32-	569.01-	41,915,442.35-
.00	.00	.00	.00	346,149.66-	.00	41,915,442.35-
670,968.79	263,440.23	43,799.69-	78,965.48-	4077,954.32-	569.01-	41,915,442.35-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

PROCESSED 05 15 88

COMMON PLANT IN SERVICE

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	159,624.27	.00	.00	25,672.17-	.00	2,432,160.87-
114,668.89	178,550.90	6.60-	98,503.30-	308,373.84-	.00	2,432,160.87-
.00	.00	.00	.00	12,950.01-	.00	1,345,127.39-
46,112.97	.00	11,033.78-	.00	155,400.12-	7,191.80	1,345,127.39-
.00	.00	.00	.00	97,717.73-	.00	3,449,458.77-
75,004.06	.00	2,391.68-	.00	1150,764.20-	6,896.91	3,449,458.77-
.00	.00	.00	.00	102.45-	.00	184,327.71-
.00	.00	.00	.00	1,229.40-	.00	184,327.71-
.00	.00	.00	.00	71,395.28-	.00	5,341,560.37-
406,940.32	2,422.53	67,112.86-	.00	857,340.47-	295.47-	5,341,560.37-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	553.92-	.00	21,162.08-
.00	.00	.00	.00	6,647.01-	.00	21,162.08-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	3,675.42-	.00	364,544.96-
14,599.85	3,941.11	.00	.00	44,105.07-	.00	364,544.96-
.00	.00	.00	.00	3,511.61-	.00	494,274.75-
2,762.25	.00	.00	.00	42,139.32-	.00	494,274.75-
.00	.00	.00	.00	486.94-	.00	15,007.34-
.00	.00	.00	.00	5,843.28-	.00	15,007.34-
.00	.00	.00	.00	350.06-	.00	105,785.42-
.00	.00	.00	.00	4,200.72-	.00	105,785.42-
.00	.00	.00	.00	2,289.18-	.00	124,094.04-
1,644.39	.00	.00	.00	25,270.23-	.00	124,094.04-
.00	159,624.27	.00	.00	218,704.77-	.00	13,877,503.70-
661,732.73	184,914.54	80,544.92-	98,503.30-	2601,313.66-	13,793.24	13,877,503.70-
.00	159,624.27	.00	.00	218,704.77-	.00	13,877,503.70-
661,732.73	184,914.54	80,544.92-	98,503.30-	2601,313.66-	13,793.24	13,877,503.70-

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
GAS PLANT IN SERVICE
PROCESSED 01 12 89

IGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	208.12-	.00	27,260.89-
.00	.00	.00	.00	2,497.44-	.00	27,260.89-
.00	.00	.00	.00	854.00-	.00	181,170.06-
457.00	.00	.00	.00	10,248.00-	.00	181,170.06-
.00	.00	.00	.00	167,171.58-	.00	23,498,951.86-
281,758.55	101,619.66	4,416.44	5,415.23-	1968,991.52-	.00	23,498,951.86-
.00	.00	.00	.00	2,301.23-	.00	550,082.94-
17,936.07	3,187.18	8,021.93-	.00	27,614.76-	1,233.51	550,082.94-
.00	.00	.00	.00	128.36-	.00	162,790.40-
3,178.76	.00	.00	.00	1,677.82-	28,484.34	162,790.40-
.00	.00	.00	.00	105,162.83-	.00	9,097,199.66-
130,255.01	199,304.99	10,833.62	130.98-	1234,360.37-	.00	9,097,199.66-
.00	.00	.00	.00	39,841.18-	.00	5,392,137.82-
133,122.11	.00	20,425.53-	.00	479,124.98-	526.45	5,392,137.82-
.00	.00	.00	.00	4,310.34-	.00	1,014,511.04-
37,400.09	668.31	4,520.88-	.00	51,724.08-	697.21-	1,014,511.04-
.00	.00	.00	.00	390.19-	.00	162,317.77-
626.39	118.00	1,187.43-	.00	4,213.35-	27,673.16-	162,317.77-
.00	.00	.00	.00	3,516.72-	.00	168,175.05-
31,269.89	407.10	200.00-	.00	38,788.43-	.00	168,175.05-
.00	.00	.00	.00	396.62-	.00	82,398.09-
.00	.00	.00	.00	4,759.44-	.00	82,398.09-
.00	.00	.00	.00	3,660.37-	.00	937,657.54-
107,578.45	2,115.59	40.00-	79,840.86-	44,346.17-	.00	937,657.54-
.00	.00	.00	.00	1,707.49-	.00	274,295.05-
12,551.81	.00	117.50-	.00	20,489.88-	449.44-	274,295.05-
.00	.00	.00	.00	4,979.05-	.00	238,273.94-
.00	.00	.00	.00	56,710.81-	1,770.15	238,273.94-
.00	.00	.00	.00	236.67-	.00	97,677.88-
.00	.00	.00	.00	2,840.04-	.00	97,677.88-
.00	.00	.00	.00	2,628.94-	.00	572,566.29-
4,491.90	53.49	452.00-	.00	31,547.28-	865.43	572,566.29-
.00	.00	.00	.00	1,755.92-	.00	279,532.95-
2,388.16	.00	1,136.00-	.00	21,071.04-	3,210.24-	279,532.95-
.00	.00	.00	.00	10.15-	.00	121.80-
.00	.00	.00	.00	121.80-	.00	121.80-
.00	.00	.00	.00	405.31-	.00	106.33
37,871.72	286.78	8,500.00-	.00	4,863.72-	.00	106.33

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

GAS PLANT IN SERVICE

IGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	328.93-	.00	53,068.76-
561.18	5.06	.00	.00	3,947.16-	865.43-	53,068.76-
.00	.00	.00	.00	14,332.48-	.00	1,927,223.14-
351,349.08	698.08	97,992.00-	.00	174,600.34-	5,693.04	1,927,223.14-
.00	.00	.00	.00	600.83-	.00	2,987.79-
.00	.00	.00	.00	7,209.96-	.00	2,987.79-
.00	.00	.00	.00	724.62-	.00	54,258.95-
10,269.58	165.68	.00	.00	8,695.44-	.00	54,258.95-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	93.60-	.00	77,593.48-
582.73	.00	363.00-	.00	1,123.20-	.00	77,593.48-
.00	.00	.00	.00	355,745.53-	.00	44,852,146.82-
163,648.48	308,629.92	127,706.21-	85,387.07-	4201,567.03-	5,677.44	44,852,146.82-
.00	.00	.00	.00	355,745.53-	.00	44,852,146.82-
163,648.48	308,629.92	127,706.21-	85,387.07-	4201,567.03-	5,677.44	44,852,146.82-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

COMMON PLANT IN SERVICE

IGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	204,051.99	.00	.00	25,672.17-	.00	2,694,753.39-
1,065.81	44,427.72	20.00-	.00	308,066.05-	.00	2,694,753.39-
.00	.00	.00	.00	13,049.02-	.00	1,487,995.00-
16,519.26	.00	3,484.13-	.00	156,588.24-	685.50	1,487,995.00-
.00	.00	.00	.00	30,257.56-	.00	4,355,009.24-
39,079.68	.00	3,734.00-	.00	939,215.60-	1,680.55-	4,355,009.24-
.00	.00	.00	.00	114.71-	.00	188,217.15-
.00	.00	30.12-	.00	1,376.52-	2,482.80-	188,217.15-
.00	.00	.00	.00	72,997.77-	.00	5,779,420.02-
506,735.34	5,663.79	83,356.19-	.00	869,071.43-	2,168.84	5,779,420.02-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	561.32-	.00	27,897.92-
.00	.00	.00	.00	6,735.84-	.00	27,897.92-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	3,741.09-	.00	402,193.42-
5,643.24	1,781.35	180.00-	.00	44,893.05-	.00	402,193.42-
.00	.00	.00	.00	3,771.97-	.00	536,107.09-
1,740.49	.00	.00	.00	43,572.83-	.00	536,107.09-
.00	.00	.00	.00	560.81-	.00	21,737.09-
.00	.00	.00	.00	6,729.75-	.00	21,737.09-
.00	.00	.00	.00	350.06-	.00	109,986.14-
.00	.00	.00	.00	4,200.72-	.00	109,986.14-
.00	.00	.00	.00	2,289.18-	.00	149,207.25-
2,526.95	.00	170.00-	.00	27,470.16-	.00	149,207.25-
.00	204,051.99	.00	.00	153,365.66-	.00	15,752,523.71-
573,310.77	51,872.86	90,974.44-	.00	2407,920.19-	1,309.01-	15,752,523.71-
.00	204,051.99	.00	.00	153,365.66-	.00	15,752,523.71-
573,310.77	51,872.86	90,974.44-	.00	2407,920.19-	1,309.01-	15,752,523.71-

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	206.95-	.00	29,744.29-
.00	.00	.00	.00	2,483.40-	.00	29,744.29-
.00	.00	.00	.00	857.09-	.00	189,389.58-
1,618.28	448.28	1.00-	.00	10,285.08-	.00	189,389.58-
.00	.00	.00	.00	170,560.70-	.00	25,299,534.64-
149,536.04	69,598.16	317.65-	397.32-	2019,002.01-	.00	25,299,534.64-
.00	.00	.00	.00	2,354.57-	.00	565,813.16-
11,708.76	2,832.97	2,017.11-	.00	28,254.84-	.00	565,813.16-
.00	.00	.00	.00	128.36-	.00	163,833.28-
565.28	41.97	109.81-	.00	1,540.32-	.00	163,833.28-
.00	.00	.00	.00	107,835.57-	.00	10,069,682.18-
103,193.55	181,323.25	13,289.98	.00	1270,289.30-	.00	10,069,682.18-
.00	.00	.00	.00	39,841.18-	.00	5,768,166.73-
118,174.74	.00	16,855.60-	.00	478,094.16-	746.11	5,768,166.73-
.00	.00	.00	.00	4,360.66-	.00	1,033,424.52-
37,255.58	.00	3,404.35-	.00	52,327.92-	436.79-	1,033,424.52-
.00	.00	.00	.00	390.19-	.00	166,297.33-
352.03	.00	.00	.00	4,682.28-	350.69	166,297.33-
.00	.00	.00	.00	3,516.72-	.00	192,705.51-
17,992.33	405.51	727.66-	.00	42,200.64-	.00	192,705.51-
.00	.00	.00	.00	489.26-	.00	85,920.67-
2,669.54	.00	321.00-	.00	5,871.12-	.00	85,920.67-
.00	.00	.00	.00	3,660.38-	.00	970,616.56-
10,343.74	629.80	.00	.00	43,932.56-	.00	970,616.56-
.00	.00	.00	.00	1,714.89-	.00	292,032.78-
2,580.74	.00	10.00-	.00	20,578.68-	270.21	292,032.78-
.00	.00	.00	.00	606.03-	.00	277,000.85-
579.30	.00	.00	.00	25,768.07-	13,538.14-	277,000.85-
.00	.00	.00	.00	236.67-	.00	100,517.92-
.00	.00	.00	.00	2,840.04-	.00	100,517.92-
.00	.00	.00	.00	2,784.70-	.00	597,523.75-
9,080.66	.00	1,400.00-	.00	32,638.12-	.00	597,523.75-
.00	.00	.00	.00	1,326.22-	.00	288,372.35-
12,007.54	5.22	3,150.00-	.00	17,702.16-	.00	288,372.35-
.00	.00	.00	.00	10.15-	.00	243.60-
.00	.00	.00	.00	121.80-	.00	243.60-
.00	.00	.00	.00	350.88-	.00	4,104.23-
.00	.00	.00	.00	4,210.56-	.00	4,104.23-

CPA185T1-BB (PL-17)
DECEMBER 1989

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
GAS PLANT IN SERVICE

ACCOUNT		BAL FORWARD	ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJ
39500	MTD	55,499.27-	.00	.00	.00	.00	332.42-	
	YTD	53,068.76-	1,179.49	46.62	.00	.00	3,989.04-	
39600	MTD	1809,175.68-	.00	.00	.00	.00	10,002.66-	
	YTD	1927,223.14-	659,158.69	232.86	406,813.00-	.00	130,871.01-	13,
39730	MTD	5,343.30-	.00	.00	.00	.00	779.23-	
	YTD	2,987.79-	6,216.02	.00	.00	.00	9,350.76-	
39750	MTD	65,050.28-	.00	.00	.00	.00	981.03-	
	YTD	54,258.95-	.00	.00	.00	.00	11,772.36-	
39760	MTD	3,011.58-	.00	.00	.00	.00	273.78-	
	YTD	.00	.00	.00	.00	.00	3,285.36-	
39800	MTD	78,621.76-	.00	.00	.00	.00	93.48-	
	YTD	77,593.48-	.00	.00	.00	.00	1,121.76-	
TOTAL	MTD	47770,394.63-	.00	.00	.00	.00	353,693.77-	
	YTD	44852,146.82-	1144,212.31	255,564.64	421,837.20-	397.32-	4223,213.35-	26,
MAJOR	MTD	47770,394.63-	.00	.00	.00	.00	353,693.77-	
	YTD	44852,146.82-	1144,212.31	255,564.64	421,837.20-	397.32-	4223,213.35-	26,

CPA185T1-BD (PL-17)
DECEMBER 1989

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
COMMON PLANT IN SERVICE

ACCOUNT		BAL FORWARD	ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJ
39000	MTD	3177,953.08-	.00	204,796.81	.00	.00	25,680.32-	
	YTD	2694,753.39-	2,907.81	1,361.75	.00	.00	308,352.76-	
39100	MTD	1613,075.18-	.00	.00	.00	.00	13,221.18-	
	YTD	1487,995.00-	31,587.31	.00	11,645.08-	.00	158,654.16-	
39110	MTD	2547,716.56-	.00	.00	.00	.00	35,720.43-	
	YTD	4355,009.24-	2433,506.07	.00	146,310.40-	.00	529,740.86-	14,
39210	MTD	197,815.67-	.00	.00	.00	.00	183.90-	
	YTD	188,217.15-	1,569.70	.00	400.00-	.00	2,856.57-	8,(
39220	MTD	5766,668.62-	.00	.00	.00	.00	34,337.97-	
	YTD	5779,420.02-	563,190.62	2,529.33	93,145.36-	.00	521,393.55-	27,
39300	MTD	.00	.00	.00	.00	.00	.00	
	YTD	.00	.00	.00	.00	.00	.00	
39400	MTD	.00	.00	.00	.00	.00	.00	
	YTD	.00	.00	.00	.00	.00	.00	
39430	MTD	7.63-	.00	.00	.00	.00	.69-	
	YTD	.00	.00	.00	.00	.00	8.32-	
39440	MTD	34,139.10-	.00	.00	.00	.00	567.38-	
	YTD	27,897.92-	.00	.00	.00	.00	6,808.56-	
39500	MTD	.00	.00	.00	.00	.00	.00	
	YTD	.00	.00	.00	.00	.00	.00	
39710	MTD	441,189.11-	.00	.00	.00	.00	3,909.34-	
	YTD	402,193.42-	3,624.67	382.38	.00	.00	46,912.08-	
39720	MTD	574,873.22-	.00	.00	.00	.00	3,771.97-	
	YTD	536,107.09-	2,610.36	115.18	.00	.00	45,263.64-	
39730	MTD	28,189.43-	.00	.00	.00	.00	586.58-	
	YTD	21,737.09-	.00	.00	.00	.00	7,038.92-	
'50	MTD	101,426.97-	.00	.00	.00	.00	159.08-	
	YTD	109,986.14-	12,254.23	155.60	.00	.00	4,009.74-	
39800	MTD	175,770.09-	.00	.00	.00	.00	2,336.29-	
	YTD	149,207.25-	498.35	.00	162.00-	.00	28,035.48-	1,
TOTAL	MTD	14658,824.66-	.00	204,796.81	.00	.00	120,475.13-	
	YTD	15752,523.71-	3051,749.12	4,544.24	251,662.84-	.00	1659,074.64-	32,
MAJOR	MTD	14658,824.66-	.00	204,796.81	.00	.00	120,475.13-	
	YTD	15752,523.71-	3051,749.12	4,544.24	251,662.84-	.00	1659,074.64-	32,

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	207.10-	.00	32,229.49-
.00	.00	.00	.00	2,485.20-	.00	32,229.49-
.00	.00	.00	.00	880.16-	.00	198,655.03-
773.00	523.47	.00	.00	10,561.92-	.00	198,655.03-
.00	.00	.00	.00	175,074.07-	.00	27,231,411.30-
92,157.64	35,838.46	2,915.53	.00	2062,788.29-	.00	27,231,411.30-
.00	.00	.00	.00	2,403.82-	.00	591,033.73-
3,904.28	977.17	1,256.18-	.00	28,845.84-	.00	591,033.73-
.00	.00	.00	.00	128.14-	.00	165,370.96-
.00	.00	.00	.00	1,537.68-	.00	165,370.96-
.00	.00	.00	.00	110,871.74-	.00	11,131,255.97-
87,093.75	150,247.09	6,646.94	.00	1305,561.57-	.00	11,131,255.97-
.00	.00	.00	.00	40,562.10-	.00	6,181,083.95-
74,744.83	.00	6,283.18-	.00	481,302.54-	76.33-	6,181,083.95-
.00	.00	.00	.00	4,404.83-	.00	1,042,822.37-
45,689.19	.00	2,229.08-	.00	52,857.96-	.00	1,042,822.37-
.00	.00	.00	.00	389.30-	.00	168,782.35-
3,978.13	48.64	1,503.95-	.00	5,007.84-	.00	168,782.35-
.00	.00	.00	.00	3,575.19-	.00	234,343.04-
1,264.75	.00	.00	.00	42,902.28-	.00	234,343.04-
.00	.00	.00	.00	552.41-	.00	92,549.59-
.00	.00	.00	.00	6,628.92-	.00	92,549.59-
.00	.00	.00	.00	3,202.04-	.00	875,624.99-
250.00	.00	.00	.00	42,570.80-	137,312.37	875,624.99-
.00	.00	.00	.00	1,261.61-	.00	217,759.04-
2,811.84	.00	395.00-	.00	19,554.12-	91,411.02	217,759.04-
.00	.00	.00	.00	1,719.54-	.00	198,804.23-
.00	.00	.00	.00	11,233.94-	89,430.56	198,804.23-
.00	.00	.00	.00	236.67-	.00	87,987.52-
.00	.00	.00	.00	2,840.04-	15,370.44	87,987.52-
.00	.00	.00	.00	2,885.43-	.00	630,859.08-
378.77	.00	.00	.00	33,714.10-	.00	630,859.08-
.00	.00	.00	.00	1,325.59-	.00	298,072.86-
6,597.32	55.61	446.36-	.00	15,907.08-	.00	298,072.86-
.00	.00	.00	.00	16.65-	.00	443.40-
.00	.00	.00	.00	199.80-	.00	443.40-
.00	.00	.00	.00	350.88-	.00	8,314.79-
.00	.00	.00	.00	4,210.56-	.00	8,314.79-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

GAS PLANT IN SERVICE

GINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	.00	.00	.00	336.24-	.00	54,975.48-
.00	.00	.00	.00	3,698.64-	4,554.85	54,975.48-
11,502.14	.00	126,000.00-	.00	10,579.46-	.00	1,897,750.18-
65,530.32	191.71	426,773.25-	.00	120,608.72-	3,088.10	1,897,750.18-
.00	.00	.00	.00	1,182.34-	.00	11,409.68-
3,811.55	.00	.00	.00	14,188.08-	5,089.38	11,409.68-
.00	.00	.00	.00	976.10-	.00	71,215.37-
6,529.14	.00	.00	.00	11,713.20-	.00	71,215.37-
.00	.00	.00	.00	261.77-	.00	6,426.60-
.00	.00	.00	.00	3,141.24-	.00	6,426.60-
.00	.00	.00	.00	94.29-	.00	66,738.29-
324.63	.00	.00	.00	1,131.48-	12,783.80	66,738.29-
11,502.14	.00	126,000.00-	.00	363,477.47-	.00	51,495,919.29-
95,839.14	187,882.15	429,324.53-	.00	4285,191.84-	358,964.19	51,495,919.29-
11,502.14	.00	126,000.00-	.00	363,477.47-	.00	51,495,919.29-
95,839.14	187,882.15	429,324.53-	.00	4285,191.84-	358,964.19	51,495,919.29-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
COMMON PLANT IN SERVICE

E 008
PROCESSED 01 28 91

GINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	ADJUSTMENT	BALANCE
.00	204,884.94	.00	.00	26,452.34-	.00	3,442,166.49-
1,179.28	4,183.53	.00	.00	311,380.34-	137,312.37-	3,442,166.49-
.00	.00	.00	.00	14,185.26-	.00	1,848,735.40-
32,505.28	.00	408.18-	.00	163,139.87-	91,396.27-	1,848,735.40-
11,014.19	.00	78,369.00-	.00	35,160.80-	.00	2,595,112.77-
11,968.95	.00	78,419.00-	.00	352,513.15-	92,712.58-	2,595,112.77-
.00	.00	.00	.00	351.08-	.00	204,153.07-
1,141.64	5.92	.00	.00	4,212.96-	3,088.10-	204,153.07-
.00	.00	.00	.00	36,577.35-	.00	5,721,767.18-
15,225.52	2,350.94	93,656.92	.00	424,486.05-	7,507.92-	5,721,767.18-
.00	.00	.00	.00	2,833.33-	.00	8,499.99-
56,000.00	.00	356,000.00-	.00	8,499.99-	.00	8,499.99-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	2.12-	.00	33.76-
.00	.00	.00	.00	25.44-	.00	33.76-
.00	.00	.00	.00	567.38-	.00	41,515.04-
.00	.00	.00	.00	6,808.56-	.00	41,515.04-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	4,178.77-	.00	474,829.53-
19,000.95	603.91	1,378.42-	.00	47,957.52-	.00	474,829.53-
.00	.00	.00	.00	4,225.52-	.00	581,514.96-
42,314.02	2,686.39	.00	.00	47,870.18-	.00	581,514.96-
.00	.00	.00	.00	811.81-	.00	41,846.94-
.00	.00	.00	.00	7,981.55-	5,089.38-	41,846.94-
.00	.00	.00	.00	.00	.00	101,586.05-
.00	.00	.00	.00	.00	.00	101,586.05-
.00	.00	.00	.00	3,149.41-	.00	242,424.27-
1,021.87	.00	.00	.00	33,809.73-	31,530.03-	242,424.27-
111,014.19	204,884.94	78,369.00-	.00	128,495.17-	.00	15,304,185.45-
580,357.51	9,830.69	342,548.68-	.00	1408,685.34-	368,636.65-	15,304,185.45-
111,014.19	204,884.94	78,369.00-	.00	128,495.17-	.00	15,304,185.45-
580,357.51	9,830.69	342,548.68-	.00	1408,685.34-	368,636.65-	15,304,185.45-

MONTANA-DAKOTA UTILITIES CO. [illegible] 006
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS PROCESSED 6. 10 92
GAS PLANT IN SERVICE

GINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	211.06-	.00	34,762.21-
.00	.00	.00	.00	2,532.72-	.00	34,762.21-
.00	.00	.00	.00	883.25-	.00	203,225.93-
3,506.79	2,521.31	.00	.00	10,599.00-	.00	203,225.93-
.00	.00	.00	.00	180,733.83-	.00	29,073,442.08-
08,283.95	72,574.40	3,390.22-	2,609.92-	2116,888.99-	.00	29,073,442.08-
.00	.00	.00	.00	2,410.66-	.00	613,744.97-
5,145.64	1,939.74	868.70-	.00	28,927.92-	.00	613,744.97-
.00	.00	.00	.00	128.81-	.00	160,213.86-
6,702.82	.00	.00	.00	1,545.72-	.00	160,213.86-
.00	.00	.00	.00	114,916.47-	.00	12,210,079.91-
12,288.21	145,015.85	9,863.03	9.25-	1345,981.78-	.00	12,210,079.91-
.00	.00	.00	.00	41,920.22-	.00	6,598,738.23-
80,430.53	.00	2,892.22-	.00	493,639.48-	1,553.11-	6,598,738.23-
.00	.00	.00	.00	4,571.03-	.00	1,048,699.13-
51,279.08	173.62	4,323.62-	.00	53,883.79-	877.95	1,048,699.13-
.00	.00	.00	.00	407.50-	.00	153,853.35-
20,057.46	1,824.81	3,065.40-	.00	4,890.00-	1,002.13	153,853.35-
.00	.00	.00	.00	3,985.46-	.00	255,558.99-
23,983.88	517.44	1,054.24-	.00	44,663.03-	.00	255,558.99-
.00	.00	.00	.00	662.45-	.00	100,498.99-
.00	.00	.00	.00	7,949.40-	.00	100,498.99-
.00	.00	.00	.00	3,201.58-	144,284.29-	853,463.59-
531.17	107.21	.00	.00	38,325.06-	59,848.08	853,463.59-
.00	.00	.00	.00	1,453.99-	90,350.27-	216,719.54-
20,130.56	.00	2,344.00-	.00	16,293.86-	453.20-	216,719.54-
.00	.00	.00	.00	1,828.98-	91,604.22-	225,038.76-
.00	.00	.00	.00	19,743.89-	6,490.64-	225,038.76-
.00	.00	.00	.00	.00	6,169.88-	6,169.88-
.00	.00	.00	.00	6,169.88-	6,169.88-	6,169.88-
.00	.00	.00	.00	201.15-	15,370.44-	108,290.91-
.00	.00	.00	.00	2,413.80-	17,889.59-	108,290.91-
.00	.00	.00	.00	2,885.43-	.00	655,172.82-
8,531.20	62.68	1,817.07-	.00	34,625.16-	3,534.61	655,172.82-
.00	.00	.00	.00	1,322.74-	.00	314,738.94-
4,600.09	.00	1,270.99-	.00	15,872.88-	4,122.30-	314,738.94-
.00	.00	.00	.00	16.65-	.00	643.20-
.00	.00	.00	.00	199.80-	.00	643.20-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

GAS PLANT IN SERVICE

IGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	608.42-	.00	12,195.34
28,131.86	.00	4,000.00-	.00	4,468.10-	846.37	12,195.34
.00	.00	.00	.00	311.88-	4,554.85-	65,040.64-
.00	.00	.00	.00	3,742.56-	6,322.60-	65,040.64-
.00	.00	.00	.00	10,130.67-	.00	1,959,795.73-
506,039.47	27.47	434,830.37-	.00	121,568.04-	11,714.08-	1,959,795.73-
.00	.00	.00	.00	.00	140,147.61-	140,147.61-
.00	.00	.00	.00	.00	140,147.61-	140,147.61-
.00	.00	.00	.00	676.58-	5,089.37-	8,863.78-
10,664.86	.00	.00	.00	8,118.96-	.00	8,863.78-
.00	.00	.00	.00	1,227.58-	.00	41,975.99-
43,825.12	145.22	.00	.00	14,730.96-	.00	41,975.99-
.00	.00	.00	.00	256.54-	.00	9,505.08-
.00	.00	.00	.00	3,078.48-	.00	9,505.08-
.00	.00	.00	.00	82.88-	12,783.80-	68,563.13-
1,084.17	.00	158.17-	.00	999.40-	1,751.44-	68,563.13-
.00	.00	.00	.00	375,035.81-	510,354.73-	55,114,751.91-
135,216.86	224,909.75	450,151.97-	2,619.17-	4395,682.78-	130,505.31-	55,114,751.91-
.00	.00	.00	.00	375,035.81-	510,354.73-	55,114,751.91-
135,216.86	224,909.75	450,151.97-	2,619.17-	4395,682.78-	130,505.31-	55,114,751.91-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

COMMON PLANT IN SERVICE

IGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	225,884.94	.00	.00	26,577.40-	144,284.29	3,789,605.70-
11,317.67	21,000.00	.00	.00	317,759.30-	61,997.58-	3,789,605.70-
.00	.00	.00	.00	14,388.90-	90,350.27	1,969,837.96-
49,846.33	.00	869.49-	.00	170,834.04-	754.64	1,969,837.96-
.00	.00	.00	.00	42,732.66-	1644,453.78	1,495,722.91-
7,906.80	.00	.00	.00	468,252.19-	1559,735.25	1,495,722.91-
.00	.00	.00	.00	.00	291,474.99-	291,474.99-
.00	.00	.00	.00	.00	291,474.99-	291,474.99-
.00	.00	.00	.00	.00	856,493.43-	856,493.43-
.00	.00	.00	.00	.00	856,493.43-	856,493.43-
.00	.00	.00	.00	.00	398,711.26-	398,711.26-
.00	.00	.00	.00	.00	398,711.26-	398,711.26-
.00	.00	.00	.00	628.86-	.00	221,193.11-
.00	.00	.00	.00	5,371.97-	11,668.07-	221,193.11-
.00	.00	.00	.00	39,246.67-	4047,602.07	1,708,371.64-
502,235.39	1,463.28	79,339.80-	.00	448,269.69-	4037,306.36	1,708,371.64-
.00	.00	.00	.00	2,833.33-	.00	42,499.95-
.00	.00	.00	.00	33,999.96-	.00	42,499.95-
.00	.00	.00	.00	.00	1539,939.72-	1,539,939.72-
.00	.00	.00	.00	.00	1539,939.72-	1,539,939.72-
.00	.00	.00	.00	.00	2507,662.35-	2,507,662.35-
.00	.00	.00	.00	.00	2507,662.35-	2,507,662.35-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	2.12-	.00	3,721.45-
.00	.00	.00	.00	25.44-	3,662.25-	3,721.45-
.00	.00	.00	.00	567.38-	.00	48,323.60-
.00	.00	.00	.00	6,808.56-	.00	48,323.60-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	4,178.77-	276,057.78	218,471.70-
31,405.13	104.91-	854.93-	.00	50,145.24-	276,057.78	218,471.70-
.00	.00	.00	.00	4,225.52-	5,245.04-	617,115.74-
19,627.57	697.93	25.00	.00	50,706.24-	5,245.04-	617,115.74-
.00	.00	.00	.00	811.81-	5,089.37	51,588.66-
.00	.00	.00	.00	9,741.72-	.00	51,588.66-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

COMMON PLANT IN SERVICE

PROCESSED 01 10 92

IGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	.00	.00	9,521.12-
91,571.27	493.66	.00	.00	.00	.00	9,521.12-
.00	.00	.00	.00	3,149.41-	32,709.09	253,703.09-
881.97	.00	331.50-	.00	37,792.92-	25,963.63	253,703.09-
.00	225,884.94	.00	.00	139,342.83-	641,019.86	16,023,958.38-
714,792.13	23,549.96	81,370.72-	.00	1599,707.27-	222,962.97	16,023,958.38-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

IGINAL COST	REM.	COMMON COST	LEASED TO OTHERS SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	225,884.94	.00	.00	.00	139,342.83-	641,019.86	16,023,958.38-
714,792.13	23,549.96	81,370.72-		.00	1599,707.27-	222,962.97	16,023,958.38-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

GAS PLANT IN SERVICE

PROCESSED 01 14 93

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	214.78-	.00	37,310.97-
.00	.00	.00	.00	2,548.76-	.00	37,310.97-
.00	.00	.00	.00	957.94-	.00	207,943.56-
3,956.71	2,552.03	.00	.00	11,226.37-	.00	207,943.56-
.00	.00	.00	.00	188,765.45-	.00	30,924,994.66-
261,776.43	81,630.92	2,741.03	.00	2197,700.96-	.00	30,924,994.66-
.00	.00	.00	.00	2,503.24-	.00	626,386.47-
14,934.74	4,119.48	1,870.26-	.00	29,825.46-	.00	626,386.47-
.00	.00	.00	.00	126.45-	.00	161,483.30-
225.00	23.32	.00	.00	1,517.76-	.00	161,483.30-
.00	.00	.00	.00	119,617.84-	.00	13,257,226.71-
152,087.98	189,283.99	8,720.45	.00	1397,314.22-	75.00	13,257,226.71-
.00	.00	.00	.00	43,364.64-	.00	7,007,820.78-
106,428.89	.00	2,245.90-	.00	513,265.54-	.00	7,007,820.78-
.00	.00	.00	.00	4,732.96-	.00	1,077,292.70-
33,968.77	.00	6,837.93-	.00	55,725.83-	1.42	1,077,292.70-
.00	.00	.00	.00	417.18-	.00	152,845.19-
5,915.92	.00	.00	.00	4,907.76-	.00	152,845.19-
.00	.00	.00	.00	177.03-	.00	375.49-
.00	.00	.00	.00	375.49-	.00	375.49-
.00	.00	.00	.00	4,058.01-	.00	267,601.12-
31,528.72	4,193.91	220.00	.00	47,984.76-	.00	267,601.12-
.00	.00	.00	.00	752.31-	.00	108,861.27-
242.94	.00	.00	.00	8,605.22-	.00	108,861.27-
.00	.00	.00	.00	3,263.22-	.00	885,120.81-
4,817.26	2,650.10	99.41	.00	39,223.99-	.00	885,120.81-
.00	.00	.00	.00	1,464.66-	.00	229,065.02-
5,186.13	.00	.00	.00	17,531.61-	.00	229,065.02-
.00	.00	.00	.00	708.14-	.00	213,174.06-
22,244.17	.00	.00	.00	8,175.62-	2,203.85-	213,174.06-
.00	.00	.00	.00	686.79-	.00	15,310.91-
.00	.00	.00	.00	8,095.50-	1,045.53-	15,310.91-
.00	.00	.00	.00	20.91-	.00	146.37-
.00	.00	.00	.00	146.37-	.00	146.37-
.00	.00	.00	.00	266.34-	.00	111,366.66-
.00	.00	.00	.00	3,075.75-	.00	111,366.66-
.00	.00	.00	.00	3,067.40-	.00	681,910.57-
9,435.02	.00	100.00-	.00	36,072.77-	.00	681,910.57-

MONTANA-DAKOTA UTILITIES CO. GE 007
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS PROCESSED 01 14 93
GAS PLANT IN SERVICE

RIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	1,423.36-	.00	314,618.66-
20,677.93	59.36	3,200.00-	.00	17,417.01-	.00	314,618.66-
.00	.00	.00	.00	33.64-	.00	1,045.38-
.00	.00	.00	.00	402.18-	.00	1,045.38-
.00	.00	.00	.00	613.52-	.00	4,889.73
.00	.00	.00	.00	7,305.61-	.00	4,889.73
.00	.00	.00	.00	395.66-	.00	69,775.35-
.00	.00	.00	.00	4,734.71-	.00	69,775.35-
.00	.00	.00	.00	10,813.09-	.00	1,979,187.10-
347,508.62	131.21	243,091.00-	.00	126,204.82-	2,264.62	1,979,187.10-
.00	.00	.00	.00	69.41-	.00	456.86-
.00	.00	.00	.00	456.86-	.00	456.86-
.00	.00	.00	.00	1,389.91-	.00	153,107.49-
8,228.01	332.27	3,720.36-	.00	16,499.73-	1,300.07-	153,107.49-
.00	.00	.00	.00	1,011.56-	.00	8,661.25-
2,283.17	75.37	.00	.00	11,019.79-	.00	8,661.25-
.00	.00	.00	.00	658.37-	.00	16,094.75-
.00	.00	.00	.00	7,230.97-	.00	16,094.75-
.00	.00	.00	.00	938.15-	.00	52,365.83-
.00	507.54	.00	.00	10,897.38-	.00	52,365.83-
.00	.00	.00	.00	268.66-	.00	12,681.20-
.00	.00	.00	.00	3,176.12-	.00	12,681.20-
.00	.00	.00	.00	90.46-	.00	69,617.45-
.00	.00	.00	.00	1,054.32-	.00	69,617.45-
.00	.00	.00	.00	392,871.08-	.00	58,638,958.21-
1031,446.41	285,559.50	249,284.56-	.00	4589,719.24-	2,208.41-	58,638,958.21-
.00	.00	.00	.00	365,687.83-	.00	53,830,142.22-
611,066.10	281,803.65	727.39	.00	4270,998.13-	76.42	53,830,142.22-
.00	.00	.00	.00	27,183.25-	.00	4,808,815.99-
420,380.31	3,755.85	250,011.95-	.00	318,721.11-	2,284.83-	4,808,815.99-
.00	.00	.00	.00	392,871.08-	.00	58,638,958.21-
1031,446.41	285,559.50	249,284.56-	.00	4589,719.24-	2,208.41-	58,638,958.21-

MONTANA-DAKOTA UTILITIES CO. GE 008
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS PROCESSED 01 14 93
COMMON PLANT IN SERVICE

RIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	225,884.94	.00	.00	26,975.69-	.00	4,045,004.69-
6,400.00	59,485.65	.00	.00	321,284.64-	.00	4,045,004.69-
.00	.00	.00	.00	13,871.33-	.00	1,954,991.54-
182,419.62	.00	811.85-	.00	167,548.17-	786.82	1,954,991.54-
.00	.00	.00	.00	32,100.94-	.00	1,806,258.32-
76,019.51	.00	13,918.44-	.00	385,022.41-	12,385.93	1,806,258.32-
.00	.00	.00	.00	11,636.29-	.00	458,766.25-
16,323.58	.00	218.76-	.00	126,018.94-	9,448.19-	458,766.25-
.00	.00	.00	.00	.00	.00	5,634.43-
584,715.28	.00	7,800.00-	.00	3,936.74-	277,880.46	5,634.43-
.00	.00	.00	.00	11.23-	.00	595,508.76-
6,268.16	.00	29.15-	.00	134.71-	250,830.75-	595,508.76-
.00	.00	.00	.00	749.81-	.00	230,084.16-
3,394.18	.00	1,817.50-	.00	8,203.11-	2,264.62-	230,084.16-
.00	.00	.00	.00	12,084.37-	.00	1,692,914.26-
134,810.89	859.07	14,484.99-	.00	140,597.28-	34,869.69	1,692,914.26-
.00	.00	.00	.00	2,833.33-	.00	76,499.91-
.00	.00	.00	.00	33,999.96-	.00	76,499.91-
.00	.00	.00	.00	11,097.83-	.00	1,567,040.65-
134,242.62	551.82	18,208.64-	.00	127,564.20-	16,122.53-	1,567,040.65-
.00	.00	.00	.00	17,774.48-	.00	2,535,372.22-
227,373.17	869.75	28,291.39-	.00	208,914.24-	18,747.16-	2,535,372.22-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	43.19-	.00	229.34-
.00	.00	.00	.00	229.34-	.00	229.34-
.00	.00	.00	.00	63.41-	.00	4,476.01-
.00	.00	.00	.00	754.56-	.00	4,476.01-
.00	.00	.00	.00	979.83-	.00	58,738.27-
.00	.00	.00	.00	10,414.67-	.00	58,738.27-
.00	.00	.00	.00	71.30-	.00	148.02-
.00	.00	.00	.00	148.02-	.00	148.02-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	1,894.47-	.00	218,443.18-
20,726.95	213.51	918.75-	.00	22,361.95-	2,368.76	218,443.18-
.00	.00	.00	.00	3,311.74-	.00	616,337.73-
40,455.50	568.48	.00	.00	40,204.73-	41.24-	616,337.73-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

COMMON PLANT IN SERVICE

PROCESSED 01 14 93

RIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	970.66-	.00	63,055.78-
.00	.00	.00	.00	11,467.12-	.00	63,055.78-
.00	.00	.00	.00	.00	.00	9,521.12-
.00	.00	.00	.00	.00	.00	9,521.12-
.00	.00	.00	.00	579.22-	.00	579.22-
.00	.00	.00	.00	579.22-	.00	579.22-
.00	.00	.00	.00	3,342.80-	.00	293,261.02-
.00	.00	.00	.00	39,557.93-	.00	293,261.02-
.00	225,884.94	.00	.00	140,391.92-	.00	16,232,864.88-
1433,149.46	62,548.28	86,499.47-	.00	1648,941.94-	30,837.17	16,232,864.88-

MONTANA-DAKOTA UTILITIES CO. GE 010

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS PROCESSED 01 14 93

COMMON LEASED TO OTHERS

RIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	225,884.94	.00	.00	140,391.92-	.00	16,232,864.88-
1433,149.46	62,548.28	86,499.47-	.00	1648,941.94-	30,837.17	16,232,864.88-
.00	225,884.94	.00	.00	140,391.92-	.00	16,232,864.88-
1433,149.46	62,548.28	86,499.47-	.00	1648,941.94-	30,837.17	16,232,864.88-

MONTANA-DAKOTA UTILITIES CO. GE 011

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS PROCESSED 01 14 93

COMMON LEASED TO OTHERS

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	2083,174.74	.00	.00	1703,381.85-	.00	279,517,264.16-
4519,327.97	847,090.20	749,071.05-	2,883.00-	20090,008.30-	76.42	279,517,264.16-

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
GAS PLANT IN SERVICE

INAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	214.78-	.00	39,888.33-
.00	.00	.00	.00	2,577.36-	.00	39,888.33-
.00	.00	.00	.00	1,098.86-	.00	211,691.25-
3,366.82	1,633.72	.00	.00	11,954.53-	3,206.30	211,691.25-
.00	.00	.00	.00	216,317.86-	270.00-	33,098,545.07-
9,595.28	60,124.58	3,971.17	.00	2357,977.16-	9,264.28-	33,098,545.07-
.00	.00	.00	.00	2,762.65-	.00	653,341.73-
5,076.39	65.67	671.04-	.00	31,426.78-	.00	653,341.73-
.00	.00	.00	.00	273.85-	.00	160,390.61-
.00	.00	.00	.00	1,910.15-	3,002.84	160,390.61-
.00	.00	.00	.00	125,828.66-	.00	14,439,009.59-
7,390.79	146,610.41	10,143.82	.00	1455,556.92-	370.98-	14,439,009.59-
.00	.00	.00	.00	45,680.36-	.00	7,457,347.92-
6,460.76	.00	4,464.18-	.00	532,699.17-	1,175.45	7,457,347.92-
.00	.00	.00	.00	4,983.06-	.00	1,103,563.67-
5,131.57	.00	3,569.60-	.00	57,859.39-	26.45	1,103,563.67-
.00	.00	.00	.00	443.00-	.00	158,618.05-
.00	.00	700.00-	.00	5,072.86-	.00	158,618.05-
.00	.00	.00	.00	220.44-	.00	3,374.26-
.00	.00	.00	.00	2,598.37-	400.40-	3,374.26-
.00	.00	.00	.00	4,077.07-	.00	259,006.81-
7,065.06	876.70	477.66-	.00	48,869.79-	.00	259,006.81-
.00	.00	.00	.00	819.26-	.00	118,303.54-
.00	.00	.00	.00	9,442.27-	.00	118,303.54-
.00	.00	.00	113.32-	3,391.47-	.00	918,606.13-
5,081.86	1,859.58	.00	113.32-	40,313.44-	.00	918,606.13-
.00	.00	.00	.00	1,589.32-	.00	243,074.35-
5,640.62	.00	1,045.00-	.00	17,891.26-	713.69-	243,074.35-
.00	.00	.00	.00	45.16-	.00	173,036.43-
2,834.63	.00	.00	.00	2,460.54-	236.46-	173,036.43-
.00	.00	.00	.00	979.13-	.00	29,327.32-
.00	.00	.00	.00	9,452.99-	4,563.42-	29,327.32-
.00	.00	.00	.00	65.44-	.00	509.50-
.00	.00	.00	.00	363.13-	.00	509.50-
.00	.00	.00	.00	267.98-	.00	114,577.50-
.00	.00	.00	.00	3,210.84-	.00	114,577.50-
.00	.00	.00	.00	3,056.73-	.00	690,286.19-
0,475.59	.00	285.00-	.00	36,801.72-	8,235.51	690,286.19-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

GAS PLANT IN SERVICE

SINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	1,498.57-	.00	320,948.34-
0,668.36	41.46	3,025.00-	.00	17,858.35-	3,843.85	320,948.34-
.00	.00	.00	.00	36.96-	.00	1,468.96-
.00	.00	.00	.00	423.58-	.00	1,468.96-
.00	.00	.00	.00	604.52-	.00	4,764.07-
.00	.00	.00	.00	7,207.95-	2,445.85-	4,764.07-
.00	.00	.00	.00	5.28-	.00	47.52-
.00	.00	.00	.00	47.52-	.00	47.52-
.00	.00	.00	.00	477.28-	.00	74,782.05-
.00	.00	.00	.00	5,006.70-	.00	74,782.05-
9,394.90	.00	32,150.00-	.00	12,165.50-	.00	2,056,755.53-
7,705.71	.00	474,364.03-	.00	135,322.28-	5,587.83-	2,056,755.53-
.00	.00	.00	.00	202.03-	.00	9,607.20-
.00	.00	.00	.00	1,480.22-	7,670.12-	9,607.20-
.00	.00	.00	.00	1,435.45-	.00	156,058.47-
3,035.20	1,183.92	170.36	.00	16,865.98-	474.48-	156,058.47-
.00	.00	.00	.00	1,070.93-	.00	23,103.67-
2,004.36-	.00	.00	.00	12,438.06-	.00	23,103.67-
.00	.00	.00	.00	724.20-	.00	24,244.30-
.00	.00	.00	.00	8,149.55-	.00	24,244.30-
.00	.00	.00	.00	942.85-	.00	63,670.59-
.00	.00	.00	.00	11,304.76-	.00	63,670.59-
.00	.00	.00	.00	268.78-	.00	15,906.32-
.00	.00	.00	.00	3,225.12-	.00	15,906.32-
.00	.00	.00	.00	93.80-	.00	70,791.57-
.00	.00	75.00-	.00	1,099.12-	.00	70,791.57-
9,394.90	.00	32,150.00-	113.32-	431,641.23-	270.00-	62,694,646.84-
7,524.78	212,396.04	474,391.16-	113.32-	4848,867.86-	12,237.11-	62,694,646.84-
.00	.00	.00	.00	402,719.85-	270.00-	57,703,080.83-
4,087.17	209,311.08	4,232.51	.00	4517,944.75-	2,624.62-	57,703,080.83-
9,394.90	.00	32,150.00-	113.32-	28,921.38-	.00	4,991,566.01-
3,437.51	3,084.96	478,623.67-	113.32-	330,923.11-	9,612.49-	4,991,566.01-
9,394.90	.00	32,150.00-	113.32-	431,641.23-	270.00-	62,694,646.84-

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
GAS PLANT IN SERVICE

INAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
7,524.78	212,396.04	474,391.16-	113.32-	4848,867.86-	12,237.11-	62,694,646.84-

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
COMMON PLANT IN SERVICE

INAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	225,884.94	.00	3,692.10-	27,469.98-	.00	4,411,614.99-
6,938.07	11,015.00	5,500.00-	4,130.02-	325,423.76-	109,509.59-	4,411,614.99-
.00	.00	.00	.00	14,149.57-	.00	2,132,494.89-
2,549.07	72.54	64.00-	.00	167,716.34-	72,344.62-	2,132,494.89-
.00	.00	.00	.00	31,843.26-	.00	2,128,116.18-
9,568.33	.00	.00	.00	384,789.14-	16,637.05-	2,128,116.18-
.00	.00	.00	.00	15,073.85-	.00	599,062.11-
4,638.45	.00	1,093.74-	.00	158,899.71-	4,940.86-	599,062.11-
.00	.00	.00	.00	.00	.00	5,634.43-
.00	.00	.00	.00	.00	.00	5,634.43-
.00	.00	.00	.00	11.21-	.00	567,457.79-
8,185.57	.00	.00	.00	134.60-	.00	567,457.79-
.00	.00	.00	.00	787.47-	.00	239,410.85-
10.00	.00	.00	.00	9,336.69-	.00	239,410.85-
.00	.00	.00	.00	12,955.09-	.00	1,759,651.17-
7,487.82	317.04	20,294.21-	.00	149,439.06-	34,808.50-	1,759,651.17-
.00	.00	.00	.00	2,833.33-	.00	110,499.87-
.00	.00	.00	.00	33,999.96-	.00	110,499.87-
.00	.00	.00	.00	11,376.38-	.00	1,489,396.44-
1,453.87	880.10	39,656.66-	.00	136,431.76-	41,398.66	1,489,396.44-
.00	.00	.00	.00	19,702.41-	.00	2,609,361.72-
3,733.29	678.51	25,034.34-	.00	221,776.80-	6,590.16-	2,609,361.72-
.00	.00	.00	.00	.00	1.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	3.74-	.00	751.23-
.00	.00	.00	.00	27.12-	724.11-	751.23-
.00	.00	.00	.00	56.75-	.00	50.11-
729.60	.00	.00	.00	550.37-	.00	50.11-
.00	.00	.00	.00	104.69-	.00	9,669.40-
.00	.00	.00	.00	888.73-	4,304.66-	9,669.40-
.00	.00	.00	.00	1,290.80-	.00	72,671.60-
.00	.00	.00	.00	12,848.73-	1,084.60-	72,671.60-
.00	.00	.00	.00	70.83-	.00	83.30-
918.31	.00	.00	.00	853.59-	.00	83.30-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	1,914.39-	.00	237,929.67-
,668.39	119.37	1,317.30	.00	22,868.80-	722.75-	237,929.67-

INAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	3,478.45-	.00	648,164.84-
6,710.90	27.99	1,743.45	.00	40,309.45-	.00	648,164.84-
.00	.00	.00	.00	1,097.03-	.00	75,481.40-
.00	.00	.00	.00	12,425.62-	.00	75,481.40-
.00	.00	.00	.00	.00	.00	9,521.12-
.00	.00	.00	.00	.00	.00	9,521.12-
.00	.00	.00	.00	625.37-	.00	7,670.09-
.00	.00	.00	.00	7,090.87-	.00	7,670.09-
.00	.00	.00	.00	3,572.92-	.00	327,101.74-
6,886.59	.00	20.00-	.00	42,827.99-	7,879.32-	327,101.74-
.00	225,884.94	.00	3,692.10-	148,418.02-	1.00	17,441,794.94-
7,478.26	13,110.55	88,602.20-	4,130.02-	1728,639.09-	218,147.56-	17,441,794.94-

SINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	225,884.94	.00	3,692.10-	148,418.02-	1.00	17,441,794.94-
7,478.26	13,110.55	88,602.20-	4,130.02-	1728,639.09-	218,147.56-	17,441,794.94-
.00	225,884.94	.00	3,692.10-	148,418.02-	1.00	17,441,794.94-
17,478.26	13,110.55	88,602.20-	4,130.02-	1728,639.09-	218,147.56-	17,441,794.94-

MONTANA-DAKOTA UTILITIES CO. PAGE 013

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS PROCESSED 01 13 94

INAL COST	REM. COST	COMMON LEASED TO OTHERS SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
9,394.90	2087,526.17	32,150.00-	3,805.42-	1775,632.65-	270.00-	297,225,953.29-
1,127.50	695,658.47	866,871.41-	5,012.16-	20714,606.59-	438,984.94-	297,225,953.29-

443,997.10

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	164.40-	.00	41,786.93-
.00	.00	.00	.00	1,898.60-	.00	41,786.93-
3,323.29	514.84	.00	.00	983.79-	.00	215,369.39-
5,438.75	2,211.80	.00	.00	11,328.69-	.00	215,369.39-
93,748.72	31,391.12	2,801.84	.00	228,157.80-	.00	35,275,735.36-
362,204.01	96,506.29	340.60	.00	2642,531.13-	6,289.94	35,275,735.36-
47,557.75	3,965.45	5,665.88-	.00	2,423.66-	897.72-	631,325.37-
53,564.31	4,545.24	6,804.16-	.00	28,391.31-	897.72-	631,325.37-
24,000.34	.00	600.00-	.00	2,043.21-	.00	164,500.36-
24,000.34	248.40	6,121.69-	.00	22,236.80-	.00	164,500.36-
35,269.62	15,337.74	1,593.27	.00	166,086.76-	.00	15,895,699.93
213,594.75	213,460.61	12,290.97	.00	1889,143.07-	6,893.60-	15,895,699.93-
.00	.00	.00	.00	46,923.94-	897.72	7,869,387.39-
140,444.26	28.34	4,954.94-	.00	550,291.31-	2,734.18	7,869,387.39-
.00	.00	.00	.00	6,612.23-	.00	1,148,925.94-
35,847.05	.00	3,465.08-	.00	77,080.42-	663.82-	1,148,925.94-
.00	.00	2,545.90-	.00	764.33-	.00	162,945.88-
9,478.47	612.40	5,952.35-	.00	9,201.50-	735.15	162,945.88-
.00	.00	.00	.00	2,509.33-	.00	23,512.76-
.00	.00	.00	.00	20,138.50-	.00	23,512.76-
5,701.90	132.87	.00	.00	4,840.89-	.00	282,767.15-
33,869.58	160.59	2,255.32-	.00	55,535.19-	.00	282,767.15-
.00	.00	.00	.00	1,171.00-	.00	129,479.27-
1,158.36	.00	.00	.00	12,334.09-	.00	129,479.27-
1,417.00	15.82	.00	.00	3,781.26-	.00	961,295.94-
1,618.38	15.82	.00	.00	44,896.23-	572.22	961,295.94
6,060.09	.00	.00	.00	1,814.68-	.00	244,765.80-
20,271.56	.00	140.55-	.00	21,822.46-	.00	244,765.80-
.00	.00	.00	.00	2,522.77-	.00	185,356.95-
.00	.00	.00	.00	11,274.52-	1,046.00-	185,356.95-
2,996.42	.00	.00	.00	2,288.21-	.00	41,042.91-
6,450.79	.00	.00	.00	18,166.38-	.00	41,042.91-
.00	.00	.00	.00	100.47-	.00	1,446.63-
.00	.00	.00	.00	937.13-	.00	1,446.63-
.00	.00	.00	.00	118.00-	.00	115,960.37-
.00	.00	.00	.00	1,382.87-	.00	115,960.37-
.00	.00	.00	.00	5,425.89-	.00	752,254.63-
5,683.71	.00	40.00-	.00	61,017.01-	6,595.14-	752,254.63-

MONTANA-DAKOTA UTILITIES CO

CUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS — PROCESS 01 17 95
GAS PLANT IN SERVICE

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
16,372.70	2.50	1,512.11-	.00	1,618.51-	.00	317,720.60-
17,231.50	45.79	1,512.11-	.00	18,536.06-	5,998.62	317,720.60-
.00	.00	.00	.00	111.67-	.00	2,436.28-
.00	.00	.00	.00	967.32-	.00	2,436.28-
.00	.00	.00	.00	2,557.90-	.00	26,767.86-
8,192.23	.00	.00	.00	30,196.02-	.00	26,767.86-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	38.56-	86.08	.00
.00	.00	.00	.00	467.40-	.00	80,350.38-
.00	.00	.00	.00	5,568.33-	.00	80,350.38-
20,127.03	.00	2,665.00-	.00	13,735.66-	.00	2,131,961.85
444,780.98	29.22	374,784.00-	.00	154,430.15-	9,197.63	2,131,961.85-
.00	.00	.00	.00	355.37-	.00	16,254.60-
.00	.00	.00	.00	3,256.82-	3,390.58-	16,254.60-
.00	.00	.00	.00	1,228.60-	.00	164,988.58-
7,505.95	531.27	2,300.00-	.00	14,667.33-	.00	164,988.58-
.00	.00	.00	.00	914.90-	.00	34,015.76-
.00	.00	.00	.00	10,912.09-	.00	34,015.76-
.00	.00	.00	.00	398.85-	.00	28,919.43-
.00	.00	.00	.00	4,675.13-	.00	28,919.43-
.00	.00	.00	.00	677.92-	.00	71,684.19-
.00	.00	.00	.00	8,013.60-	.00	71,684.19-
.00	.00	.00	.00	387.99-	.00	20,562.20-
.00	.00	.00	.00	4,655.88-	.00	20,562.20-
.00	.00	.00	.00	57.83-	.00	71,415.65
.00	.00	.00	.00	624.08-	.00	71,415.65
256,574.86	51,360.34	8,593.78-	.00	501,245.22-	.00	67,110,636.34-
1391,334.98	318,395.77	395,698.63-	.00	5736,148.58-	6,126.96	67,110,636.34-

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
3,904.15	.00	3,232.06-	.00	.00	.00	672.09
3,904.15	.00	3,232.06-	.00	.00	.00	672.09
3,904.15	.00	3,232.06-	.00	.00	.00	672.09
3,904.15	.00	3,232.06-	.00	.00	.00	672.09
213,505.77	51,342.02	7,648.73-	.00	462,681.34-	.00	61,840,763.64-
883,504.03	317,773.67	20,154.03-	.00	5320,110.61-	1,304.13	61,840,763.64-
46,973.24	18.32	4,177.11-	.00	38,563.88-	.00	5,269,200.61-
511,735.10	622.10	378,776.66-	.00	416,037.97-	4,822.83	5,269,200.61
260,479.01	51,360.34	11,825.84-	.00	501,245.22-	.00	67,109,964.25-
1395,239.13	318,395.77	398,930.69-	.00	5736,148.58-	6,126.96	67,109,964.25-

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS
COMMON PLANT IN SERVICE

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
450.00	225,956.77	52.50-	.00	57,087.40-	.00	4,947,871.45-
76,339.95	3,348.28	52.50-	.00	615,319.97-	572.22-	4,947,871.45-
.00	.00	.00	.00	4,384.59-	.00	2,108,685.95-
76,446.67	.24-	300.77-	.00	52,447.52-	110.80	2,108,685.95-
.00	.00	.00	.00	41,036.79-	.00	2,501,559.17-
89,596.68	.00	4,000.00-	.00	460,085.67-	1,046.00	2,501,559.17-
12,209.82	.00	268.00-	.00	23,402.74-	.00	747,281.95-
71,970.57	.00	3,693.70-	.00	216,749.80-	253.09	747,281.95-
.00	.00	.00	.00	.00	.00	5,634.43-
.00	.00	.00	.00	.00	.00	5,634.43-
.00	.00	.00	.00	80.42-	.00	493,734.75-
74,235.51	.00	.00	.00	512.47-	.00	493,734.75-
.00	.00	.00	.00	1,708.71-	.00	258,206.55-
2,004.82	.00	345.00-	.00	20,455.52-	.00	258,206.55-
28,272.16	86.18	4.31	.00	13,592.28-	3,642.82-	1,652,552.58-
317,142.07	934.85	65,427.26-	.00	158,989.91-	13,438.84	1,652,552.58-
.00	.00	.00	.00	2,833.33-	.00	144,499.83-
.00	.00	.00	.00	33,999.96-	.00	144,499.83-
31,166.50	.00	9,350.00-	.00	11,991.18-	3,642.82	1,453,887.74-
207,542.69	426.92	37,016.70-	.00	141,085.31-	5,641.10	1,453,887.74-
74,642.38	266.77	10,397.50-	.00	21,157.49-	.00	2,500,094.66-
516,488.58	1,236.63	119,899.98-	.00	246,389.75-	42,168.42-	2,500,094.66-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	5.39-	.00	815.91-
.00	.00	.00	.00	64.68-	.00	815.91-
.00	.00	.00	.00	279.01-	.00	446.62-
976.78	.00	.00	.00	1,373.29-	.00	446.62-
.00	.00	.00	.00	278.62-	.00	12,480.12-
.00	.00	.00	.00	2,810.72-	.00	12,480.12-
.00	.00	.00	.00	4,996.87-	.00	111,528.37-
19,508.57	.00	.00	.00	58,365.34-	.00	111,528.37-
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	514.08-	597.38	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	1,892.67-	.00	259,946.17-
687.33	148.00	.00	.00	22,851.83-	.00	259,946.17-

MONTANA-DAKOTA UTILITIES CO.

ACCUMULATED PROVISION FOR DEPRECIATION, BY ACCOUNT TOTALS

COMMON PLANT IN SERVICE

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
29,299.79	1,129.37	.00	.00	5,633.56-	.00	673,619.88-
38,615.39	1,353.16	.00	.00	65,423.59-	.00	673,619.88-
.00	.00	.00	.00	3,077.63-	.00	109,887.39-
.00	.00	.00	.00	34,405.99-	.00	109,887.39-
.00	.00	.00	.00	.00	.00	9,521.12-
.00	.00	.00	.00	.00	.00	9,521.12-
.00	.00	.00	.00	748.73-	.00	15,673.25-
.00	.00	.00	.00	8,003.16-	.00	15,673.25-
.00	.00	.00	.00	926.70-	.00	337,056.16-
366.88	.00	.00	.00	10,321.30-	.00	337,056.16-
176,040.65	227,439.09	20,063.69-	.00	195,114.11-	.00	18,344,984.05-
1491,922.49	7,447.60	230,735.91-	.00	2150,169.86-	21,653.43-	18,344,984.05-

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00
176,040.65	227,439.09	20,063.69-	.00	195,114.11-	.00	18,344,984.05-
1491,922.49	7,447.60	230,735.91-	.00	2150,169.86-	21,653.43-	18,344,984.05-
176,040.65	227,439.09	20,063.69-	.00	195,114.11-	.00	18,344,984.05-
1491,922.49	7,447.60	230,735.91-	.00	2150,169.86-	21,653.43-	18,344,984.05-

ORIGINAL COST	REM. COST	SALVAGE(CR)	OTHER COST	PROVISION(CR)	TRANSFER	BALANCE
1700,870.90	2401,537.93	73,737.64-	.00	1905,387.21-	3.87-	312,822,478.80-
5619,497.29	1193,418.45	370,868.42-	.00	22040,949.89-	2,377.06	312,822,478.80-
				-3.87	3.87	
				(22,040,953 76)	2,380.93	

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 1995

Project No. and Description	RWIP Beginning Balance 1/1/95	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/95
00001 Montana Dakota Utilities Co.					
AS Allocated State					
1 Electric					
D Dist (E/360-373,G/374-387)					
368 Line Transformers	.00	3,407.50-	.00	2,306.60	1,100.90-
370 Meters	.00	175.55-	.00	175.55	.00
D Dist (E/360-373,G/374-387)	.00	3,583.05-	.00	2,482.15	1,100.90-
1 Electric	.00	3,583.05-	.00	2,482.15	1,100.90-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
381 Positive Meters	.00	5,114.56-	176.07-	.00	5,290.63-
383 Service Regulators	.00	2,904.98-	824.06-	.00	3,729.04-
D Dist (E/360-373,G/374-387)	.00	8,019.54-	1,000.13-	.00	9,019.67-
2 Natural Gas	.00	8,019.54-	1,000.13-	.00	9,019.67-
AS Allocated State	.00	11,602.59-	1,000.13-	2,482.15	10,120.57-
ER East River					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	78.80-	481.52	134.20-	268.52
379 Meas. & Reg. Equip.-City	.00	375.22-	.00	.00	375.22-
D Dist (E/360-373,G/374-387)	.00	454.02-	481.52	134.20-	106.70-
2 Natural Gas	.00	454.02-	481.52	134.20-	106.70-
ER East River	.00	454.02-	481.52	134.20-	106.70-
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	166,332.45-	1,668.22	165,296.98	632.75
3922 Vehicles	.00	15,821.00-	.00	1,950.00	13,871.00-
3971 Fixed Radio Comm. Equipme	.00	.00	157.08	.00	157.08
G General (E,G/389-398)	.00	182,153.45-	1,825.30	167,246.98	13,081.17-
0 Common Utility	.00	182,153.45-	1,825.30	167,246.98	13,081.17-

Project No. and Description	RWIP Beginning Balance 1/1/95	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/95
00001 Montana Dakota Utilities Co.					
MT Montana					
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	.00	1,219.14	.00	1,241.70
364 Poles, Towers & Fixtures	.00	194.90-	6,739.30	5,828.58-	715.82
365 Overhead Conductors & Dev	.00	557.15-	8,531.59	10,529.12-	1,732.79
367 Under. Conductors & Devic	.00	5,270.04-	33,771.39	.00	28,501.35
369 Services	.00	1,479.14-	14,028.03	.00	12,548.89
371 Install. on Cust. Premise	.00	1,482.96-	3,451.63	.00	1,968.67
373 Street Light. & Signal Sy	.00	1,063.83-	4,136.69	.00	3,072.86
D Dist (E/360-373,G/374-387)	.00	10,048.02-	71,877.77	16,357.70-	49,782.08
G General (E,G/389-398)					
3922 Vehicles	.00	4,800.00-	.00	4,800.00	9,500.00-
3962 Power Operated Equipment	.00	9,200.00-	257.77	7,442.23	1,500.00-
G General (E,G/389-398)	.00	14,000.00-	257.77	12,242.23	11,000.00-
S Steam Production (E/310-316					
311807 Structures & Improvements	.00	.00	41,913.89	.00	801,853.08-
S Steam Production (E/310-316	.00	.00	41,913.89	.00	801,853.08-
T Elec Transmission (350-358)					
353 Station Equipment	.00	347.20-	12,393.44	6,113.12-	9,199.89
355 Poles & Fixtures	.00	13,023.05-	23,713.40	1,224.21	11,914.56
356 Overhead Conductor & Devi	.00	.00	1,503.86	631.53-	872.33
T Elec Transmission (350-358)	.00	13,370.25-	37,610.70	5,520.44-	21,986.78
1 Electric	.00	37,418.27-	151,660.13	9,635.91-	741,084.22-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	257.00	.00	257.00
376 Mains	.00	892.93-	94,574.16	47,522.84-	48,947.50
378 Meas. & Reg. Equip. - Gen	.00	.00	135.73-	.00	246.73-
3871 Cathodic Protection Equip	.00	477.66-	117.57	.00	360.09-
D Dist (E/360-373,G/374-387)	.00	1,370.59-	94,813.00	47,522.84-	48,597.68
G General (E,G/389-398)					
3921 Trailers	.00	100.00-	16.26	.00	83.74-
3922 Vehicles	.00	11,604.37-	.00	7,803.37	3,801.00-
3962 Power Operated Equipment	.00	272,550.00-	70.49	135,800.00	136,679.51-
G General (E,G/389-398)	.00	284,254.37-	86.75	143,603.37	140,564.25-

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 1995

Project No. and Description	RWIP Beginning Balance 1/1/95	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/95
00001 Montana Dakota Utilities Co.					
MT Montana					
2 Natural Gas					
G General (E,G/389-398)					
2 Natural Gas	.00	285,624.96-	94,899.75	96,080.53	91,966.57-
3 Propane					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	.00	2,608.33	1,993.95-	625.36
D Dist (E/360-373,G/374-387)	.00	.00	2,608.33	1,993.95-	625.36
G General (E,G/389-398)					
3922 Vehicles	.00	3,950.00-	.00	.00	3,950.00-
G General (E,G/389-398)	.00	3,950.00-	.00	.00	3,950.00-
3 Propane	.00	3,950.00-	2,608.33	1,993.95-	3,324.64-
MT Montana	.00	509,146.68-	250,993.51	251,697.65	849,456.60-
ND North Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	13,010.00-	18,563.36	12,490.00	18,043.36
3911 Office Furniture & Equipm	.00	150.00-	898.00-	.00	9,368.47
3913 Personal Computer Equipme	.00	1,681.00-	.00	.00	1,681.00-
3922 Vehicles	.00	29,344.00-	.00	4,782.00	24,562.00-
3923 Aircraft	.00	294,553.79-	.00	294,553.79	.00
3941 Misc. Tools - Nonunitized	.00	40.00-	.00	.00	40.00-
3972 Mobile Radio Comm. Equipm	.00	.00	669.88	.00	837.37
398 Miscellaneous Equipment	.00	630.00-	.00	630.00	.00
G General (E,G/389-398)	.00	339,408.79-	18,335.24	312,455.79	1,966.20
0 Common Utility	.00	339,408.79-	18,335.24	312,455.79	1,966.20
1 Electric					
D Dist (E/360-373,G/374-387)					
3601 Land	.00	10.00-	342.50	.00	332.50
362 Station Equipment	.00	362.81-	4,059.72	.00	3,717.75
364 Poles, Towers & Fixtures	.00	6,809.50-	14,721.14	5,411.36-	2,721.25
365 Overhead Conductors & Dev	.00	1,216.10-	3,928.92	126.84	2,839.66
367 Under. Conductors & Devic	.00	40,906.64-	93,676.44	13,481.88-	39,287.92
369 Services	.00	6,099.49-	21,450.41	4,335.78-	11,015.14
371 Install. on Cust. Premise	.00	4,299.54-	4,142.88	100.50	56.16-

Project No. and Description	RWIP Beginning Balance 1/1/95	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/95
00001 Montana Dakota Utilities Co.					
ND North Dakota					
1 Electric					
D Dist (E/360-373,G/374-387)					
373 Street Light. & Signal Sy	.00	10,448.10-	7,654.60	2,125.67	667.83-
D Dist (E/360-373,G/374-387)	.00	70,152.18-	149,976.61	20,876.01-	59,190.23
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	166.83	166.83-	220,646.00-
3911 Office Furniture & Equipm	.00	425.00-	.00	.00	425.00-
3922 Vehicles	.00	46,597.00-	3,968.44-	43,219.96	7,345.48-
3962 Power Operated Equipment	.00	8,952.13-	.00	8,952.15	.02
3971 Fixed Radio Comm. Equipme	.00	.00	59.45	59.45-	.00
3976 Scada System	.00	.00	2,260.25	.00	2,260.25
G General (E,G/389-398)	.00	55,974.13-	1,481.91-	51,945.83	226,156.21-
O Other Production (E/340-346					
341806 Structures & Improvements	.00	.00	.00	.00	2,487.25-
O Other Production (E/340-346	.00	.00	.00	.00	2,487.25-
S Steam Production (E/310-316					
310804 Land and Land Rights-Beul	.00	.00	1,572.86	.00	1,826,014.47-
311807 Structures & Improvements	.00	.00	.00	.00	138,503.00-
312805 Boiler Plant Equipment	.00	.00	1,061.07	.00	2,455.35-
312810 Boiler Plant Equipment	.00	.00	316.23	.00	316.23
312830 Boiler Plant Equipment	.00	.00	74,562.45-	.00	72,591.40-
314830 Turbogenerator Units	.00	.00	773.46	.00	773.46
316830 Misc. Power Plant Equipme	.00	105.00-	4,524.52-	.00	4,629.52-
S Steam Production (E/310-316	.00	105.00-	75,363.35-	.00	2,043,104.05-
T Elec Transmission (350-358)					
353 Station Equipment	.00	800.00-	11,280.44	4,184.40-	7,885.02
355 Poles & Fixtures	.00	66,010.63-	30,425.37	25,732.90	9,805.13-
356 Overhead Conductor & Devi	.00	1,833.16-	6,666.99	.00	4,833.83
T Elec Transmission (350-358)	.00	68,643.79-	48,372.80	21,548.50	2,913.72
1 Electric	.00	194,875.10-	121,504.15	52,618.32	2,209,643.56-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	642.50	.00	642.50
376 Mains	.00	27.88-	82,063.79	51,518.07-	31,456.49
378 Meas. & Reg. Equip. - Gen	.00	.00	243.73	.00	292.02
380 Services	.00	.00	8.27	.00	8.27

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 1995

Project No. and Description	RWIP Beginning Balance 1/1/95	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/95
00001 Montana Dakota Utilities Co.					
ND North Dakota					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
D Dist (E/360-373,G/374-387)	.00	27.88-	82,958.29	51,518.07-	32,399.28
G General (E,G/389-398)					
3911 Office Furniture & Equipm	.00	746.00-	120.89-	.00	866.89-
3922 Vehicles	.00	21,465.00-	.00	11,747.00	9,718.00-
3961 Work Equipment Trailers	.00	.00	5,406.00-	.00	5,406.00-
3962 Power Operated Equipment	.00	189,147.95-	125,425.00-	262,267.95	52,305.00-
G General (E,G/389-398)	.00	211,358.95-	130,951.89-	274,014.95	68,295.89-
2 Natural Gas	.00	211,386.83-	47,993.60-	222,496.88	35,896.61-
ND North Dakota	.00	745,670.72-	91,845.79	587,570.99	2,243,573.97-
SD South Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	8,753.68-	414.46	8,339.22	.00
3911 Office Furniture & Equipm	.00	190.00-	.00	95.00	95.00-
3972 Mobile Radio Comm. Equipm	.00	.00	13.72	.00	13.72
G General (E,G/389-398)	.00	8,943.68-	428.18	8,434.22	81.28-
0 Common Utility	.00	8,943.68-	428.18	8,434.22	81.28-
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	1,457.48-	3,085.05	768.90-	858.67
364 Poles, Towers & Fixtures	.00	.00	153.68	.00	153.68
365 Overhead Conductors & Dev	.00	.00	7,812.10	10,049.99-	.00
367 Under. Conductors & Devic	.00	5,581.81-	22,188.54	.00	16,606.73
369 Services	.00	1,662.26-	7,192.69	.00	5,530.43
371 Install. on Cust. Premise	.00	964.51-	1,193.80	.00	229.29
373 Street Light. & Signal Sy	.00	2,556.95-	6,376.50	.00	3,819.55
D Dist (E/360-373,G/374-387)	.00	12,223.01-	48,002.36	10,818.89-	27,198.35
G General (E,G/389-398)					
390 Structures & Improvements	.00	35,542.82-	1,008.92	13,072.82	21,461.08-
3922 Vehicles	.00	11,348.00-	17,000.00-	5,725.38	22,500.00-
G General (E,G/389-398)	.00	46,890.82-	15,991.08-	18,798.20	43,961.08-

Project No. and Description	RWIP Beginning Balance 1/1/95	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/95
00001 Montana Dakota Utilities Co.					
SD South Dakota					
1 Electric					
S Steam Production (E/310-316					
311814 Structures & Improvements	.00	.00	.00	.00	6,366.00-
312861 Boiler Plant Equipment	.00	681.00-	8,233.79	.00	7,552.79
316861 Misc. Power Plant Equipme	.00	10,025.69-	.00	.00	10,025.69-
S Steam Production (E/310-316	.00	10,706.69-	8,233.79	.00	8,838.90-
T Elec Transmission (350-358)					
353 Station Equipment	.00	.00	1,335.48	1,335.48-	.00
355 Poles & Fixtures	.00	9.40	1,218.08-	1,219.05	294.67
356 Overhead Conductor & Devi	.00	7,371.77-	9,916.00	3,741.52-	1,197.29-
T Elec Transmission (350-358)	.00	7,362.37-	10,033.40	3,857.95-	902.62-
1 Electric	.00	77,182.89-	50,278.47	4,121.36	26,504.25-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	.00	37,895.99	25,226.76-	12,669.23
378 Meas. & Reg. Equip. - Gen	.00	1,797.01-	14,721.87	2,960.37-	9,964.49
379 Meas. & Reg. Equip.-City	.00	4,191.96-	248.54	.00	3,943.42-
3863 CNG Demonstration	.00	1,055.96-	212.58	.00	843.38-
D Dist (E/360-373,G/374-387)	.00	7,044.93-	53,078.98	28,187.13-	17,846.92
G General (E,G/389-398)					
390 Structures & Improvements	.00	154,090.00-	934.46	153,155.54	.00
3911 Office Furniture & Equipm	.00	533.00-	48.76	.00	484.24-
3921 Trailers	.00	316.00-	47.25	.00	268.75-
3922 Vehicles	.00	30,416.60-	2,271.30	7,268.58	20,876.72-
3941 Misc. Tools - Nonunitized	.00	100.00-	.00	.00	100.00-
3962 Power Operated Equipment	.00	292,679.16-	.00	292,679.15	.01-
3971 Fixed Radio Comm. Equipme	.00	.00	295.17	61.95-	233.22
3973 General Telephone Comm. E	.00	.00	106.00	106.00-	.00
G General (E,G/389-398)	.00	478,134.76-	3,702.94	452,935.32	21,496.50-
2 Natural Gas	.00	485,179.69-	56,781.92	424,748.19	3,649.58-
SD South Dakota	.00	571,306.26-	107,488.57	437,303.77	30,235.11-
WY Wyoming					
0 Common Utility					
G General (E,G/389-398)					

Project	No. and Description	RWIP Beginning Balance 1/1/95	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/95
3911	Office Furniture & Equipm	.00	21.25-	.00	.00	21.25-
3922	Vehicles	.00	.00	390.01	.00	390.01
G	General (E,G/389-398)	.00	21.25-	390.01	.00	368.76
0	Common Utility	.00	21.25-	390.01	.00	368.76
1	Electric					
D	Dist (E/360-373,G/374-387)					
362	Station Equipment	.00	.00	630.90	621.22-	9.68
364	Poles, Towers & Fixtures	.00	.00	24,156.45	37,594.92-	6,959.75
365	Overhead Conductors & Dev	.00	4,349.70-	16,110.44	17,436.66-	338.28-
367	Under. Conductors & Devic	.00	251.81-	9,177.86	482.80-	8,443.25
369	Services	.00	29.30	5,226.56	.00	5,255.86
371	Install. on Cust. Premise	.00	.00	207.14-	.00	207.14-
373	Street Light. & Signal Sy	.00	.00	722.05	.00	722.05
D	Dist (E/360-373,G/374-387)	.00	4,572.21-	55,817.12	56,135.60-	20,845.17
T	Elec Transmission (350-358)					
353	Station Equipment	.00	.00	2,470.02	2,470.02-	.00
T	Elec Transmission (350-358)	.00	.00	2,470.02	2,470.02-	.00
1	Electric	.00	4,572.21-	58,287.14	58,605.62-	20,845.17
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
376	Mains	.00	.00	24,142.79	17,556.59-	6,586.20
D	Dist (E/360-373,G/374-387)	.00	.00	24,142.79	17,556.59-	6,586.20
G	General (E,G/389-398)					
390	Structures & Improvements	.00	.00	100.00-	.00	100.00-
3921	Trailers	.00	2,000.00-	.00	.00	2,000.00-
3922	Vehicles	.00	999.20-	.00	999.20	.00
3962	Power Operated Equipment	.00	98,900.00-	.00	85,400.00	13,500.00-
G	General (E,G/389-398)	.00	101,899.20-	100.00-	86,399.20	15,600.00-
2	Natural Gas	.00	101,899.20-	24,042.79	68,842.61	9,013.80-
WY	Wyoming	.00	106,492.66-	82,719.94	10,236.99	12,200.13
00001	Montana Dakota Utilities Co.	.00	1,944,672.93-	532,529.20	1,289,157.35	3,121,292.82-

Project No. and Description	RWIP Beginning Balance 1/1/96	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/96
00001 Montana Dakota Utilities Co.					
AS Allocated State					
1 Electric					
D Dist (E/360-373,G/374-387)					
368 Line Transformers	1,100.90-	2,179.24-	.00	4,201.34	921.20
370 Meters	.00	21.38-	.00	21.38	.00
D Dist (E/360-373,G/374-387)	1,100.90-	2,200.62-	.00	4,222.72	921.20
1 Electric	1,100.90-	2,200.62-	.00	4,222.72	921.20
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
381 Positive Meters	5,290.63-	6,207.50-	16.08-	8,202.93	3,311.28-
383 Service Regulators	3,729.04-	9,746.99-	824.06	9,852.04	2,799.93-
D Dist (E/360-373,G/374-387)	9,019.67-	15,954.49-	807.98	18,054.97	6,111.21-
2 Natural Gas	9,019.67-	15,954.49-	807.98	18,054.97	6,111.21-
AS Allocated State	10,120.57-	18,155.11-	807.98	22,277.69	5,190.01-
ER East River					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	268.52	37.00-	1,350.09	1,490.17-	91.44
379 Meas. & Reg. Equip.-City	375.22-	.00	.00	375.22	.00
D Dist (E/360-373,G/374-387)	106.70-	37.00-	1,350.09	1,114.95-	91.44
G General (E,G/389-398)					
3962 Power Operated Equipment	.00	3,750.00-	.00	.00	3,750.00-
G General (E,G/389-398)	.00	3,750.00-	.00	.00	3,750.00-
2 Natural Gas	106.70-	3,787.00-	1,350.09	1,114.95-	3,658.56-
ER East River	106.70-	3,787.00-	1,350.09	1,114.95-	3,658.56-
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	632.75	19,220.21-	.00	18,593.21	5.75
3911 Office Furniture & Equipm	.00	1,358.00-	13,266.54-	100.00	14,524.54-
3922 Vehicles	13,871.00-	6,220.00-	.00	20,091.00	.00

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
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Project No. and Description	RWIP Beginning Balance 1/1/96	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/96
00001 Montana Dakota Utilities Co.					
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
3941 Misc. Tools - Nonunitized	.00	.00	.00	50.00	50.00
3971 Fixed Radio Comm. Equipme	157.08	.00	.00	157.08-	.00
G General (E,G/389-398)	13,081.17-	26,798.21-	13,266.54-	38,677.13	14,468.79-
0 Common Utility	13,081.17-	26,798.21-	13,266.54-	38,677.13	14,468.79-
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	1,241.70	.00	.00	1,241.70-	.00
364 Poles, Towers & Fixtures	715.82	31.15-	7,795.57	7,999.18-	481.06
365 Overhead Conductors & Dev	1,732.79	2,845.60-	5,438.14	3,423.54-	901.79
367 Under. Conductors & Devic	28,501.35	10,339.77-	28,778.94	37,595.85-	9,344.67
369 Services	12,548.89	1,922.97-	12,455.44	22,075.45-	1,005.91
371 Install. on Cust. Premise	1,968.67	4,500.19-	4,451.21	2,818.49-	898.80-
373 Street Light. & Signal Sy	3,072.86	1,853.71-	3,625.59	4,638.26-	206.48
D Dist (E/360-373,G/374-387)	49,782.08	21,493.39-	62,544.89	79,792.47-	11,041.11
G General (E,G/389-398)					
3922 Vehicles	9,500.00-	16,713.00-	.00	22,413.00	3,800.00-
3962 Power Operated Equipment	1,500.00-	3,500.00-	4.15	4,995.85	.00
3971 Fixed Radio Comm. Equipme	.00	.00	126.98	126.98-	.00
G General (E,G/389-398)	11,000.00-	20,213.00-	131.13	27,281.87	3,800.00-
O Other Production (E/340-346					
341852 Structures & Improvements	.00	.00	3,000.00	.00	3,000.00
O Other Production (E/340-346	.00	.00	3,000.00	.00	3,000.00
S Steam Production (E/310-316					
311807 Structures & Improvements	801,853.08-	.00	26,154.88	26,153.80-	801,852.00-
314820 Turbogenerator Units	.00	.00	10,853.00-	.00	10,853.00-
S Steam Production (E/310-316	801,853.08-	.00	15,301.88	26,153.80-	812,705.00-
T Elec Transmission (350-358)					
353 Station Equipment	9,199.89	50.00-	8,338.35-	496.20	1,307.74
355 Poles & Fixtures	11,914.56	1,989.52-	2,628.65	12,551.81-	1.88
356 Overhead Conductor & Devi	872.33	.00	4,383.23	2,818.85-	2,436.71
T Elec Transmission (350-358)	21,986.78	2,039.52-	1,326.47-	14,874.46-	3,746.33
1 Electric	741,084.22-	43,745.91-	79,651.43	93,538.86-	798,717.56-

Project	No. and Description	RWIP Beginning Balance 1/1/96	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/96
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
3741	Land	257.00	.00	.00	.00	257.00
376	Mains	48,947.50	.00	85,730.00	121,908.43-	12,769.07
378	Meas. & Reg. Equip. - Gen	246.73-	.00	1,665.13	108.96	1,527.36
3863	CNG Demonstration	.00	.00	24.36-	.00	24.36-
3871	Cathodic Protection Equip	360.09-	.00	.00	360.09	.00
D	Dist (E/360-373,G/374-387)	48,597.68	.00	87,370.77	121,439.38-	14,529.07
G	General (E,G/389-398)					
390	Structures & Improvements	.00	69,105.50-	.00	69,105.50	.00
3911	Office Furniture & Equipm	.00	1,053.54-	.00	1,053.54	.00
3921	Trailers	83.74-	101.99-	.00	185.73	.00
3922	Vehicles	3,801.00-	29,053.67-	483.41-	33,338.08	.00
3941	Misc. Tools - Nonunitized	.00	.00	1,518.60-	.00	1,518.60-
3943	Vehicle Maintenance Equip	.00	400.00-	.00	400.00	.00
3962	Power Operated Equipment	136,679.51-	19,575.00-	.00	143,504.51	12,750.00-
3971	Fixed Radio Comm. Equipme	.00	.00	194.00	194.00-	.00
G	General (E,G/389-398)	140,564.25-	119,289.70-	1,808.01-	247,393.36	14,268.60-
2	Natural Gas	91,966.57-	119,289.70-	85,562.76	125,953.98	260.47
3	Propane					
D	Dist (E/360-373,G/374-387)					
376	Mains	625.36	.00	5.75-	619.61-	.00
383	Service Regulators	.00	.00	15.00	.00	15.00
D	Dist (E/360-373,G/374-387)	625.36	.00	9.25	619.61-	15.00
G	General (E,G/389-398)					
3922	Vehicles	3,950.00-	.00	.00	3,950.00	.00
G	General (E,G/389-398)	3,950.00-	.00	.00	3,950.00	.00
3	Propane	3,324.64-	.00	9.25	3,330.39	15.00
MT	Montana	849,456.60-	189,833.82-	151,956.90	74,422.64	812,910.88-
ND	North Dakota					
0	Common Utility					
G	General (E,G/389-398)					
390	Structures & Improvements	18,043.36	.00	3,775.80	21,819.16-	.00
3911	Office Furniture & Equipm	9,368.47	1,251.50-	.00	534.00	8,650.97
3913	Personal Computer Equipme	1,681.00-	1,085.50-	.00	.00	2,766.50-

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
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As of December 31, 1996

Project No. and Description	RWIP Beginning Balance 1/1/96	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/96
00001 Montana Dakota Utilities Co.					
ND North Dakota					
0 Common Utility					
G General (E,G/389-398)					
3922 Vehicles	24,562.00-	76,626.49-	45.46	96,601.30	4,541.73-
3923 Aircraft	.00	.00	.00	.00	.00
3941 Misc. Tools - Nonunitized	40.00-	20.00-	.00	.00	60.00-
3971 Fixed Radio Comm. Equipme	.00	.00	190.29	190.29-	.00
3972 Mobile Radio Comm. Equipm	837.37	.00	477.13	733.98-	580.52
398 Miscellaneous Equipment	.00	.00	.00	.00	.00
G General (E,G/389-398)	1,966.20	78,983.49-	4,488.68	74,391.87	1,863.26
0 Common Utility	1,966.20	78,983.49-	4,488.68	74,391.87	1,863.26
1 Electric					
D Dist (E/360-373,G/374-387)					
3601 Land	332.50	.00	74.24	406.74-	.00
362 Station Equipment	3,717.75	15,634.04-	2,224.75	10,633.01	941.47
364 Poles, Towers & Fixtures	2,721.25	5,235.12-	28,897.82	21,631.57-	4,752.38
365 Overhead Conductors & Dev	2,839.66	4,268.25-	7,260.03	4,398.21-	1,433.23
367 Under. Conductors & Devic	39,287.92	36,907.43-	83,144.27	88,305.98-	2,781.22-
369 Services	11,015.14	7,225.69-	19,214.54	20,782.88-	2,221.11
371 Install. on Cust. Premise	56.16-	6,885.43-	6,247.74	1,002.41	308.56
373 Street Light. & Signal Sy	667.83-	5,261.53-	7,353.03	910.01-	513.66
D Dist (E/360-373,G/374-387)	59,190.23	81,417.49-	154,416.42	124,799.97-	7,389.19
G General (E,G/389-398)					
390 Structures & Improvements	220,646.00-	17,190.65-	1,127.00	16,563.65	220,146.00-
3911 Office Furniture & Equipm	425.00-	907.80-	.00	1,332.80	.00
3922 Vehicles	7,345.48-	22,134.04-	7,678.23-	39,340.70	2,182.95
3962 Power Operated Equipment	.02	52,919.00-	107.40	52,811.58	.00
3971 Fixed Radio Comm. Equipme	.00	.00	210.45	210.45-	.00
3975 Supervisory & Telemeterin	.00	.00	1,157.63	1,157.63-	.00
3976 Scada System	2,260.25	.00	2,239.00-	.00	21.25
G General (E,G/389-398)	226,156.21-	93,151.49-	7,314.75-	108,680.65	217,941.80-
O Other Production (E/340-346					
341806 Structures & Improvements	2,487.25-	.00	.00	.00	2,487.25-
O Other Production (E/340-346	2,487.25-	.00	.00	.00	2,487.25-
S Steam Production (E/310-316					
310804 Land and Land Rights-Beul	1,826,014.47-	.00	2,123.02	2,123.02-	1,826,014.47-
311807 Structures & Improvements	138,503.00-	.00	.00	.00	138,503.00-
311830 Structures & Improvements	.00	.00	1,082.29	1,000.00-	82.29
312805 Boiler Plant Equipment	2,455.35-	.00	2,123.02	2,123.02-	2,455.35-

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00001 Montana Dakota Utilities Co.					
ND North Dakota					
1 Electric					
S Steam Production (E/310-316					
312810 Boiler Plant Equipment	316.23	.00	110.00	426.23-	.00
312830 Boiler Plant Equipment	72,591.40-	.00	65,228.58	9,007.78	1,644.96
314830 Turbogenerator Units	773.46	.00	899.92	240.42-	1,432.96
316810 Misc. Power Plant Equipme	.00	800.00-	.00	800.00	.00
316830 Misc. Power Plant Equipme	4,629.52-	1,000.00-	8,117.12	2,020.08-	467.52
S Steam Production (E/310-316	2,043,104.05-	1,800.00-	79,683.95	1,875.01	1,963,345.09-
T Elec Transmission (350-358)					
353 Station Equipment	7,885.02	11,966.83-	45,571.69	40,150.90-	1,338.98
355 Poles & Fixtures	9,805.13-	73,549.64-	91,858.76	7,513.66-	990.33
356 Overhead Conductor & Devi	4,833.83	23,938.98-	15,806.75	5,104.41-	8,402.81-
T Elec Transmission (350-358)	2,913.72	109,455.45-	153,237.20	52,768.97-	6,073.50-
1 Electric	2,209,643.56-	285,824.43-	380,022.82	67,013.28-	2,182,458.45-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	642.50	.00	.00	642.50-	.00
376 Mains	31,456.49	742.52-	92,230.83	89,405.48-	33,539.32
378 Meas. & Reg. Equip. - Gen	292.02	.00	365.27	292.02-	365.27
380 Services	8.27	.00	8.27-	.00	.00
3871 Cathodic Protection Equip	.00	.00	271.94-	178.08-	450.02-
D Dist (E/360-373,G/374-387)	32,399.28	742.52-	92,315.89	90,518.08-	33,454.57
G General (E,G/389-398)					
3911 Office Furniture & Equipm	866.89-	620.38-	.00	1,201.57	285.70-
3922 Vehicles	9,718.00-	5,777.00-	7,430.65-	18,996.75	3,928.90-
3944 Vehicle Refueling Equipme	.00	.00	6,059.65-	6,059.65	.00
3961 Work Equipment Trailers	5,406.00-	.00	51.00	5,355.00	.00
3962 Power Operated Equipment	52,305.00-	100,347.00-	38,640.00-	189,292.00	2,000.00-
G General (E,G/389-398)	68,295.89-	106,744.38-	52,079.30-	220,904.97	6,214.60-
2 Natural Gas	35,896.61-	107,486.90-	40,236.59	130,386.89	27,239.97
ND North Dakota	2,243,573.97-	472,294.82-	424,748.09	137,765.48	2,153,355.22-
SD South Dakota					
0 Common Utility					
G General (E,G/389-398)					

Project	No. and Description	RWIP Beginning Balance 1/1/96	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/96
390	Structures & Improvements	.00	7,533.00-	599.64	7,433.36	500.00
3911	Office Furniture & Equipm	95.00-	357.55-	.00	452.55	.00
3972	Mobile Radio Comm. Equipm	13.72	.00	152.04	165.76-	.00
G	General (E,G/389-398)	81.28-	7,890.55-	751.68	7,720.15	500.00
0	Common Utility	81.28-	7,890.55-	751.68	7,720.15	500.00
1	Electric					
D	Dist (E/360-373,G/374-387)					
362	Station Equipment	858.67	.00	896.59	1,641.75-	113.51
364	Poles, Towers & Fixtures	153.68	2,480.05-	18,793.47	3,333.95-	13,133.15
365	Overhead Conductors & Dev	.00	.00	.00	.00	.00
367	Under. Conductors & Devic	16,606.73	3,881.14-	25,090.81	32,807.80-	5,008.60
369	Services	5,530.43	1,946.46-	9,227.79	11,289.93-	1,521.83
371	Install. on Cust. Premise	229.29	671.54-	1,124.68	617.34-	65.09
373	Street Light. & Signal Sy	3,819.55	766.15-	3,825.89	4,852.10-	2,027.19
D	Dist (E/360-373,G/374-387)	27,198.35	9,745.34-	58,959.23	54,542.87-	21,869.37
G	General (E,G/389-398)					
3890	Land and Land Rights	.00	4,519.37-	675.00	3,844.37	.00
390	Structures & Improvements	21,461.08-	.00	.00	21,461.08	.00
3911	Office Furniture & Equipm	.00	174.50-	.00	174.50	.00
3922	Vehicles	22,500.00-	23,457.00-	66.94	45,890.06	.00
G	General (E,G/389-398)	43,961.08-	28,150.87-	741.94	71,370.01	.00
S	Steam Production (E/310-316					
311814	Structures & Improvements	6,366.00-	.00	.00	.00	6,366.00-
311861	Structures & Improvements	.00	13.62-	.00	13.62	.00
312861	Boiler Plant Equipment	7,552.79	743,788.20-	16,741.15	727,439.26	7,945.00
316861	Misc. Power Plant Equipme	10,025.69-	888.70-	50,155.34	11,595.39	50,836.34
S	Steam Production (E/310-316	8,838.90-	744,690.52-	66,896.49	739,048.27	52,415.34
T	Elec Transmission (350-358)					
353	Station Equipment	.00	.00	.00	.00	.00
355	Poles & Fixtures	294.67	.00	15,685.65	15,913.32-	67.00
356	Overhead Conductor & Devi	1,197.29-	98.48	261.77	837.04	.00
T	Elec Transmission (350-358)	902.62-	98.48	15,947.42	15,076.28-	67.00
1	Electric	26,504.25-	782,488.25-	142,545.08	740,799.13	74,351.71
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
375	Structures & Improvements	.00	.00	602.06	602.06-	.00

Project No. and Description	RWIP Beginning Balance 1/1/96	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/96
00001 Montana Dakota Utilities Co.					
SD South Dakota					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	12,669.23	.00	32,667.32	44,309.84-	1,026.71
378 Meas. & Reg. Equip. - Gen	9,964.49	3,577.40-	2,623.21	8,942.74-	67.56
379 Meas. & Reg. Equip.-City	3,943.42-	381.16-	134.72	.00	4,189.86-
385 Ind. meas. & Reg. Station	.00	.00	462.47	.00	462.47
3863 CNG Demonstration	843.38-	212.58-	.00	.00	1,055.96-
D Dist (E/360-373,G/374-387)	17,846.92	4,171.14-	36,489.78	53,854.64-	3,689.08-
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	218.79	218.79-	.00
3911 Office Furniture & Equipm	484.24-	100.00-	.00	584.24	.00
3921 Trailers	268.75-	.00	.00	268.75	.00
3922 Vehicles	20,876.72-	17,486.07-	2,317.85	34,144.94	1,900.00-
3941 Misc. Tools - Nonunitized	100.00-	900.00-	286.74	713.26	.00
3962 Power Operated Equipment	.01-	332,057.62-	250.84	279,306.79	52,500.00-
3971 Fixed Radio Comm. Equipme	233.22	.00	.00	233.22-	.00
3973 General Telephone Comm. E	.00	.00	.00	.00	.00
G General (E,G/389-398)	21,496.50-	350,543.69-	3,074.22	314,565.97	54,400.00-
2 Natural Gas	3,649.58-	354,714.83-	39,564.00	260,711.33	58,089.08-
4 Non-utility					
D Dist (E/360-373,G/374-387)					
3871 Cathodic Protection Equip	.00	16,733.50-	2,841.95	13,891.55	.00
D Dist (E/360-373,G/374-387)	.00	16,733.50-	2,841.95	13,891.55	.00
4 Non-utility	.00	16,733.50-	2,841.95	13,891.55	.00
SD South Dakota	30,235.11-	1,161,827.13-	185,702.71	1,023,122.16	16,762.63
WY Wyoming					
0 Common Utility					
G General (E,G/389-398)					
3911 Office Furniture & Equipm	21.25-	115.00-	.00	166.25	30.00
3922 Vehicles	390.01	4,971.00-	5.50	4,971.00	395.51
G General (E,G/389-398)	368.76	5,086.00-	5.50	5,137.25	425.51
0 Common Utility	368.76	5,086.00-	5.50	5,137.25	425.51

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00001 Montana Dakota Utilities Co.					
WY Wyoming					
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	9.68	.00	344.15	353.83-	.00
364 Poles, Towers & Fixtures	6,959.75	8,350.49-	23,402.99	21,740.83-	271.42
365 Overhead Conductors & Dev	338.28-	.00	3,612.16	3,273.88-	.00
367 Under. Conductors & Devic	8,443.25	3,748.17-	17,611.39	22,108.27-	198.20
369 Services	5,255.86	343.47-	4,544.13	7,255.32-	2,201.20
370 Meters	.00	10,000.00-	1,055.83	8,944.17	.00
371 Install. on Cust. Premise	207.14-	1,182.88-	4,576.28	2,922.72-	263.54
373 Street Light. & Signal Sy	722.05	.00	664.87	1,187.16-	199.76
D Dist (E/360-373,G/374-387)	20,845.17	23,625.01-	55,811.80	49,897.84-	3,134.12
G General (E,G/389-398)					
3976 Scada System	.00	250.00-	.00	250.00	.00
G General (E,G/389-398)	.00	250.00-	.00	250.00	.00
T Elec Transmission (350-358)					
353 Station Equipment	.00	.00	.00	.00	.00
356 Overhead Conductor & Devi	.00	.00	653.00	.00	653.00
T Elec Transmission (350-358)	.00	.00	653.00	.00	653.00
1 Electric	20,845.17	23,875.01-	56,464.80	49,647.84-	3,787.12
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	6,586.20	.00	17,521.31	22,330.64-	1,776.87
D Dist (E/360-373,G/374-387)	6,586.20	.00	17,521.31	22,330.64-	1,776.87
G General (E,G/389-398)					
390 Structures & Improvements	100.00-	126,992.71-	1,099.00	125,993.71	.00
3911 Office Furniture & Equipm	.00	22.00-	.00	22.00	.00
3921 Trailers	2,000.00-	110.50-	.00	2,110.50	.00
3922 Vehicles	.00	7,850.00-	.00	7,850.00	.00
3941 Misc. Tools - Nonunitized	.00	.00	747.96-	747.96	.00
3962 Power Operated Equipment	13,500.00-	2,246.33-	.00	15,746.33	.00
G General (E,G/389-398)	15,600.00-	137,221.54-	351.04	152,470.50	.00
2 Natural Gas	9,013.80-	137,221.54-	17,872.35	130,139.86	1,776.87
WY Wyoming	12,200.13	166,182.55-	74,342.65	85,629.27	5,989.50

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00001 Montana Dakota Utilities Co.					
WY Wyoming					
2 Natural Gas					
G General (E,G/389-398)					
00001 Montana Dakota Utilities Co.	3,121,292.82-	2,012,080.43-	838,908.42	1,342,102.29	2,952,362.54-

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Project No. and Description	RWIP Beginning Balance 1/1/97	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/97
00001 Montana Dakota Utilities Co.					
AS Allocated State					
1 Electric					
D Dist (E/360-373,G/374-387)					
368 Line Transformers	921.20	2,463.95-	.00	422.35	1,120.40-
370 Meters	.00	1,010.41-	.00	175.55-	1,185.96-
D Dist (E/360-373,G/374-387)	921.20	3,474.36-	.00	246.80	2,306.36-
1 Electric	921.20	3,474.36-	.00	246.80	2,306.36-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
381 Positive Meters	3,311.28-	1,260.69-	.00	3,569.20	1,002.77-
383 Service Regulators	2,799.93-	5,470.23-	1,273.72	7,613.53	617.09
D Dist (E/360-373,G/374-387)	6,111.21-	6,730.92-	1,273.72	11,182.73	385.68-
2 Natural Gas	6,111.21-	6,730.92-	1,273.72	11,182.73	385.68-
AS Allocated State	5,190.01-	10,205.28-	1,273.72	11,429.53	2,692.04-
ER East River					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	91.44	61.48-	244.67	274.46-	.17
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	91.44	61.48-	244.67	274.46-	.17
G General (E,G/389-398)					
3962 Power Operated Equipment	3,750.00-	49,300.00-	.00	53,050.00	.00
G General (E,G/389-398)	3,750.00-	49,300.00-	.00	53,050.00	.00
2 Natural Gas	3,658.56-	49,361.48-	244.67	52,775.54	.17
ER East River	3,658.56-	49,361.48-	244.67	52,775.54	.17
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	5.75	19,363.50-	950.00	18,407.75	.00
3911 Office Furniture & Equipm	14,524.54-	365.50-	.00	14,890.04	.00
3921 Trailers	.00	8,054.30-	.00	8,054.30	.00

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00001 Montana Dakota Utilities Co.					
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
3922 Vehicles	.00	.00	42.74	.00	42.74
3941 Misc. Tools - Nonunitized	50.00	.00	.00	50.00-	.00
3971 Fixed Radio Comm. Equipme	.00	.00	27.09	27.09-	.00
G General (E,G/389-398)	14,468.79-	27,783.30-	1,019.83	41,275.00	42.74
0 Common Utility	14,468.79-	27,783.30-	1,019.83	41,275.00	42.74
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	10,458.03-	2,338.30	8,807.22	687.49
364 Poles, Towers & Fixtures	481.06	2,700.69-	23,398.60	2,424.94-	18,754.03
365 Overhead Conductors & Dev	901.79	.00	14,448.01	15,349.80-	.00
367 Under. Conductors & Devic	9,344.67	7,099.58-	22,773.92	21,534.40-	3,484.61
369 Services	1,005.91	1,195.38-	11,024.77	8,927.39-	1,907.91
371 Install. on Cust. Premise	898.80-	3,696.24-	3,350.33	1,146.76	97.95-
373 Street Light. & Signal Sy	206.48	1,012.86-	3,290.57	2,081.36-	402.83
D Dist (E/360-373,G/374-387)	11,041.11	26,162.78-	80,624.50	40,363.91-	25,138.92
G General (E,G/389-398)					
3922 Vehicles	3,800.00-	8,255.00-	24.37	12,055.00	24.37
3962 Power Operated Equipment	.00	175.00-	573.85	398.85-	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3974 Carrier Current Comm. Equ	.00	.00	257.52	257.52-	.00
3975 Supervisory & Telemeterin	.00	.00	128.32	128.32-	.00
G General (E,G/389-398)	3,800.00-	8,430.00-	984.06	11,270.31	24.37
O Other Production (E/340-346					
341852 Structures & Improvements	3,000.00	.00	3,000.00-	.00	.00
O Other Production (E/340-346	3,000.00	.00	3,000.00-	.00	.00
S Steam Production (E/310-316					
311807 Structures & Improvements	801,852.00-	.00	4,068.65-	.00	805,920.65-
312820 Boiler Plant Equipment	.00	87.50-	22,243.73	.00	22,156.23
314820 Turbogenerator Units	10,853.00-	.00	.00	10,853.00	.00
316820 Misc. Power Plant Equipme	.00	511.00-	.00	511.00	.00
S Steam Production (E/310-316	812,705.00-	598.50-	18,175.08	11,364.00	783,764.42-
T Elec Transmission (350-358)					
353 Station Equipment	1,307.74	.00	6,101.67	6,882.98-	526.43

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00001 Montana Dakota Utilities Co.					
MT Montana					
1 Electric					
T Elec Transmission (350-358)					
355 Poles & Fixtures	1.88	15,092.85-	12,980.49	9.29-	2,119.77-
356 Overhead Conductor & Devi	2,436.71	.00	1,767.01-	669.70-	.00
T Elec Transmission (350-358)	3,746.33	15,092.85-	17,315.15	7,561.97-	1,593.34-
1 Electric	798,717.56-	50,284.13-	114,098.79	25,291.57-	760,194.47-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	257.00	.00	.00	257.00-	.00
376 Mains	12,769.07	119,316.45-	106,680.36	88,555.58-	88,422.60-
378 Meas. & Reg. Equip. - Gen	1,527.36	.00	1,250.71	1,608.74-	1,169.33
3863 CNG Demonstration	24.36-	.00	67.85	.00	43.49
3871 Cathodic Protection Equip	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	14,529.07	119,316.45-	107,998.92	90,421.32-	87,209.78-
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	564.40	.00	564.40
390 Structures & Improvements	.00	.00	450.00	450.00-	.00
3911 Office Furniture & Equipm	.00	108.25-	.00	108.25	.00
3921 Trailers	.00	30.00-	.00	30.00	.00
3922 Vehicles	.00	5,160.00-	100.00	5,160.00	100.00
3941 Misc. Tools - Nonunitized	1,518.60-	1,557.75-	1,518.60	1,557.75	.00
3943 Vehicle Maintenance Equip	.00	.00	.00	.00	.00
3962 Power Operated Equipment	12,750.00-	251,651.00-	.00	264,401.00	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	14,268.60-	258,507.00-	2,633.00	270,807.00	664.40
2 Natural Gas	260.47	377,823.45-	110,631.92	180,385.68	86,545.38-
3 Propane					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	.00	665.13	347.27-	317.86
383 Service Regulators	15.00	.00	15.00-	.00	.00
D Dist (E/360-373,G/374-387)	15.00	.00	650.13	347.27-	317.86
G General (E,G/389-398)					
3922 Vehicles	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	.00	.00	.00

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00001 Montana Dakota Utilities Co.					
MT Montana					
3 Propane					
G General (E,G/389-398)					
3 Propane	15.00	.00	650.13	347.27-	317.86
MT Montana	812,910.88-	455,890.88-	226,400.67	196,021.84	846,379.25-
ND North Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	26,000.00-	46,007.90	23,191.00	43,198.90
3911 Office Furniture & Equipm	8,650.97	1,362.83-	1,200.00	9,436.14-	948.00-
3913 Personal Computer Equipme	2,766.50-	.00	.00	2,766.50	.00
3922 Vehicles	4,541.73-	32,733.00-	8.27-	34,152.00	3,131.00-
3923 Aircraft	.00	.00	.00	.00	.00
3941 Misc. Tools - Nonunitized	60.00-	.00	.00	60.00	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3972 Mobile Radio Comm. Equipm	580.52	.00	519.31	580.52-	519.31
398 Miscellaneous Equipment	.00	.00	.00	.00	.00
G General (E,G/389-398)	1,863.26	60,095.83-	47,718.94	50,152.84	39,639.21
0 Common Utility	1,863.26	60,095.83-	47,718.94	50,152.84	39,639.21
1 Electric					
D Dist (E/360-373,G/374-387)					
3601 Land	.00	2,000.00-	1,214.03	480.00-	1,265.97-
362 Station Equipment	941.47	7,304.44-	4,369.62	951.75-	2,945.10-
364 Poles, Towers & Fixtures	4,752.38	1,682.24-	16,056.39	17,214.65-	1,895.67
365 Overhead Conductors & Dev	1,433.23	3,480.07-	23,130.36	21,083.52-	.00
367 Under. Conductors & Devic	2,781.22-	25,060.43-	82,054.35	45,942.16-	8,270.54
369 Services	2,221.11	6,697.67-	24,610.04	17,705.78-	2,427.70
371 Install. on Cust. Premise	308.56	6,398.27-	6,047.09	824.39	781.77
373 Street Light. & Signal Sy	513.66	9,762.84-	7,822.29	2,286.57	859.68
D Dist (E/360-373,G/374-387)	7,389.19	62,385.96-	165,304.17	100,266.90-	10,024.29
G General (E,G/389-398)					
390 Structures & Improvements	220,146.00-	.00	.00	.00	220,146.00-
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3914 Prime/Sun Computers	.00	1,000.00-	.00	1,000.00	.00
3922 Vehicles	2,182.95	18,472.00-	1,925.00-	18,214.05	.00
3962 Power Operated Equipment	.00	16,000.00-	.00	15,750.00	250.00-
3971 Fixed Radio Comm. Equipme	.00	.00	109.84	109.84-	.00
3975 Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976 Scada System	21.25	.00	3,612.14	3,612.14-	21.25

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00001	Montana Dakota Utilities Co.					
ND	North Dakota					
1	Electric					
G	General (E,G/389-398)					
G	General (E,G/389-398)	217,941.80-	35,472.00-	1,796.98	31,242.07	220,374.75-
O	Other Production (E/340-346					
341806	Structures & Improvements	2,487.25-	.00	.00	.00	2,487.25-
O	Other Production (E/340-346	2,487.25-	.00	.00	.00	2,487.25-
S	Steam Production (E/310-316					
310804	Land and Land Rights-Beul	1,826,014.47-	.00	762.42	.00	1,825,252.05-
311807	Structures & Improvements	138,503.00-	.00	.00	.00	138,503.00-
311810	Structures & Improvements	.00	.00	2,335.88	2,335.88-	.00
311830	Structures & Improvements	82.29	119.91-	10,457.53	10,419.91-	.00
312805	Boiler Plant Equipment	2,455.35-	.00	762.43	.00	1,692.92-
312810	Boiler Plant Equipment	.00	.00	8,210.12	1,253.35-	6,956.77
312830	Boiler Plant Equipment	1,644.96	32,938.84-	175,630.24	141,634.40-	2,701.96
314830	Turbogenerator Units	1,432.96	3,000.00-	8,735.78	2,899.49-	4,269.25
316810	Misc. Power Plant Equipme	.00	.00	.00	.00	.00
316830	Misc. Power Plant Equipme	467.52	2,574.40-	11,559.43	9,478.80-	26.25-
S	Steam Production (E/310-316	1,963,345.09-	38,633.15-	218,453.83	168,021.83-	1,951,546.24-
T	Elec Transmission (350-358)					
353	Station Equipment	1,338.98	.00	7,620.47	8,646.81-	312.64
355	Poles & Fixtures	990.33	8,122.10-	4,464.71	37,879.50-	40,546.56-
356	Overhead Conductor & Devi	8,402.81-	2,300.64-	14,620.35	324.03	4,240.93
T	Elec Transmission (350-358)	6,073.50-	10,422.74-	26,705.53	46,202.28-	35,992.99-
1	Electric	2,182,458.45-	146,913.85-	412,260.51	283,248.94-	2,200,376.94-
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
3741	Land	.00	.00	.00	.00	.00
376	Mains	33,539.32	200.18-	95,674.94	102,870.70-	26,143.38
378	Meas. & Reg. Equip. - Gen	365.27	.00	5,752.67	3,393.58-	2,724.36
3871	Cathodic Protection Equip	450.02-	.00	.00	450.02	.00
D	Dist (E/360-373,G/374-387)	33,454.57	200.18-	101,427.61	105,814.26-	28,867.74
G	General (E,G/389-398)					
390	Structures & Improvements	.00	.00	320.00	.00	320.00
3911	Office Furniture & Equipm	285.70-	.00	.00	285.70	.00
3922	Vehicles	3,928.90-	25,907.35-	220.38	19,756.97	9,858.90-
3942	Misc. Tools - Unitized	.00	689.00-	.00	689.00	.00

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00001 Montana Dakota Utilities Co.					
ND North Dakota					
2 Natural Gas					
G General (E,G/389-398)					
3944 Vehicle Refueling Equipme	.00	.00	.00	.00	.00
3961 Work Equipment Trailers	.00	.00	.00	.00	.00
3962 Power Operated Equipment	2,000.00-	461,481.85-	41,000.00-	504,481.85	.00
3971 Fixed Radio Comm. Equipme	.00	.00	91.95	.00	91.95
G General (E,G/389-398)	6,214.60-	488,078.20-	40,367.67-	525,213.52	9,446.95-
2 Natural Gas	27,239.97	488,278.38-	61,059.94	419,399.26	19,420.79
ND North Dakota	2,153,355.22-	695,288.06-	521,039.39	186,303.16	2,141,316.94-
SD South Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	500.00	.00	.00	500.00-	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3972 Mobile Radio Comm. Equipm	.00	.00	.00	.00	.00
G General (E,G/389-398)	500.00	.00	.00	500.00-	.00
0 Common Utility	500.00	.00	.00	500.00-	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	113.51	.00	1,493.83	1,607.34-	.00
364 Poles, Towers & Fixtures	13,133.15	26.72-	2,745.75	15,852.18-	.00
365 Overhead Conductors & Dev	.00	.00	.00	.00	.00
367 Under. Conductors & Devic	5,008.60	3,036.06-	13,848.55	14,468.86-	1,352.23
369 Services	1,521.83	1,765.70-	9,145.48	7,516.25-	1,385.36
371 Install. on Cust. Premise	65.09	613.88-	1,544.30	984.38-	11.13
373 Street Light. & Signal Sy	2,027.19	5,921.61-	5,784.20	1,351.74-	538.04
D Dist (E/360-373,G/374-387)	21,869.37	11,363.97-	34,562.11	41,780.75-	3,286.76
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	.00	.00	.00
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	2,500.00-	123.60-	2,623.60	.00
3976 Scada System	.00	.00	1,203.32	581.86-	621.46
G General (E,G/389-398)	.00	2,500.00-	1,079.72	2,041.74	621.46

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00001 Montana Dakota Utilities Co.					
SD South Dakota					
1 Electric					
S Steam Production (E/310-316					
311814 Structures & Improvements	6,366.00-	.00	.00	.00	6,366.00-
311861 Structures & Improvements	.00	.00	.00	.00	.00
312861 Boiler Plant Equipment	7,945.00	.00	.00	7,945.00-	.00
316861 Misc. Power Plant Equipme	50,836.34	279.96-	42,255.74-	8,564.26-	263.62-
S Steam Production (E/310-316	52,415.34	279.96-	42,255.74-	16,509.26-	6,629.62-
T Elec Transmission (350-358)					
353 Station Equipment	.00	.00	11,244.74	11,244.74-	.00
355 Poles & Fixtures	67.00	.00	.00	67.00-	.00
356 Overhead Conductor & Devi	.00	2,066.02-	10,146.56	6,320.60-	1,759.94
T Elec Transmission (350-358)	67.00	2,066.02-	21,391.30	17,632.34-	1,759.94
1 Electric	74,351.71	16,209.95-	14,777.39	73,880.61-	961.46-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	480.00	.00	480.00
375 Structures & Improvements	.00	.00	.00	.00	.00
376 Mains	1,026.71	.00	33,694.07	22,509.56-	12,211.22
378 Meas. & Reg. Equip. - Gen	67.56	712.79-	3,048.64	2,230.77-	172.64
379 Meas. & Reg. Equip.-City	4,189.86-	.00	.00	4,189.86	.00
385 Ind. meas. & Reg. Station	462.47	500.00-	.00	37.53	.00
3863 CNG Demonstration	1,055.96-	404.43-	.00	.00	1,460.39-
D Dist (E/360-373,G/374-387)	3,689.08-	1,617.22-	37,222.71	20,512.94-	11,403.47
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	814.44	127.91-	686.53
3911 Office Furniture & Equipm	.00	5.00-	.00	.00	5.00-
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	1,900.00-	2,787.74-	189.34	4,498.40	.00
3941 Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3962 Power Operated Equipment	52,500.00-	363,409.00-	52,646.71	363,409.00	146.71
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3973 General Telephone Comm. E	.00	.00	.00	.00	.00
G General (E,G/389-398)	54,400.00-	366,201.74-	53,650.49	367,779.49	828.24
2 Natural Gas	58,089.08-	367,818.96-	90,873.20	347,266.55	12,231.71
4 Non-utility					
D Dist (E/360-373,G/374-387)					

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3871	Cathodic Protection Equip	.00	.00	.00	.00	.00
D	Dist (E/360-373,G/374-387)	.00	.00	.00	.00	.00
4	Non-utility	.00	.00	.00	.00	.00
SD	South Dakota	16,762.63	384,028.91-	105,650.59	272,885.94	11,270.25
WY	Wyoming					
0	Common Utility					
G	General (E,G/389-398)					
3911	Office Furniture & Equipm	30.00	45.00-	.00	15.00	.00
3922	Vehicles	395.51	1,300.00-	390.01-	1,294.50	.00
G	General (E,G/389-398)	425.51	1,345.00-	390.01-	1,309.50	.00
0	Common Utility	425.51	1,345.00-	390.01-	1,309.50	.00
1	Electric					
D	Dist (E/360-373,G/374-387)					
362	Station Equipment	.00	.00	.00	.00	.00
364	Poles, Towers & Fixtures	271.42	7,360.90-	20,280.89	4,381.01-	8,810.40
365	Overhead Conductors & Dev	.00	.00	.00	.00	.00
367	Under. Conductors & Devic	198.20	1,582.24-	9,880.92	5,677.39-	2,819.49
369	Services	2,201.20	187.21-	3,765.82	4,019.71-	1,760.10
370	Meters	.00	.00	.00	.00	.00
371	Install. on Cust. Premise	263.54	1,580.86-	3,374.51	1,654.48-	402.71
373	Street Light. & Signal Sy	199.76	1,614.46	1,631.75	1,307.93-	2,138.04
D	Dist (E/360-373,G/374-387)	3,134.12	9,096.75-	38,933.89	17,040.52-	15,930.74
G	General (E,G/389-398)					
3976	Scada System	.00	.00	.00	.00	.00
G	General (E,G/389-398)	.00	.00	.00	.00	.00
T	Elec Transmission (350-358)					
353	Station Equipment	.00	.00	.00	.00	.00
356	Overhead Conductor & Devi	653.00	1,993.42-	2,749.77	1,409.35-	.00
T	Elec Transmission (350-358)	653.00	1,993.42-	2,749.77	1,409.35-	.00
1	Electric	3,787.12	11,090.17-	41,683.66	18,449.87-	15,930.74
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					

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376	Mains	1,776.87	.00	13,307.57	10,976.98-	4,107.46
D	Dist (E/360-373,G/374-387)	1,776.87	.00	13,307.57	10,976.98-	4,107.46
G	General (E,G/389-398)					
390	Structures & Improvements	.00	.00	.00	.00	.00
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3921	Trailers	.00	.00	.00	.00	.00
3922	Vehicles	.00	.00	.00	.00	.00
3941	Misc. Tools - Nonunitized	.00	105.00-	.00	.00	105.00-
3962	Power Operated Equipment	.00	103,600.00-	.00	103,600.00	.00
G	General (E,G/389-398)	.00	103,705.00-	.00	103,600.00	105.00-
2	Natural Gas	1,776.87	103,705.00-	13,307.57	92,623.02	4,002.46
WY	Wyoming	5,989.50	116,140.17-	54,601.22	75,482.65	19,933.20
00001	Montana Dakota Utilities Co.	2,952,362.54-	1,710,914.78-	909,210.26	794,898.66	2,959,184.61-

Project No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
00001 Montana Dakota Utilities Co.					
AS Allocated State					
1 Electric					
D Dist (E/360-373,G/374-387)					
368 Line Transformers	1,120.40-	9,079.60-	.00	1,120.40	9,079.60-
370 Meters	1,185.96-	502.96	.00	1,362.00	679.00
D Dist (E/360-373,G/374-387)	2,306.36-	8,576.64-	.00	2,482.40	8,400.60-
1 Electric	2,306.36-	8,576.64-	.00	2,482.40	8,400.60-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
381 Positive Meters	1,002.77-	881.40-	.00	395.20	1,488.97-
383 Service Regulators	617.09	3,169.16-	194.86	1,656.02	701.19-
D Dist (E/360-373,G/374-387)	385.68-	4,050.56-	194.86	2,051.22	2,190.16-
2 Natural Gas	385.68-	4,050.56-	194.86	2,051.22	2,190.16-
AS Allocated State	2,692.04-	12,627.20-	194.86	4,533.62	10,590.76-
ER East River					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	.17	23.63-	239.70	95.47-	120.77
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	.17	23.63-	239.70	95.47-	120.77
G General (E,G/389-398)					
3962 Power Operated Equipment	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	.00	.00	.00
2 Natural Gas	.17	23.63-	239.70	95.47-	120.77
ER East River	.17	23.63-	239.70	95.47-	120.77
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	100.00-	.00	100.00	.00
3921 Trailers	.00	.00	.00	.00	.00

Project No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
00001 Montana Dakota Utilities Co.					
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
3922 Vehicles	42.74	3,008.00-	.00	2,965.26	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	42.74	3,108.00-	.00	3,065.26	.00
0 Common Utility	42.74	3,108.00-	.00	3,065.26	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	687.49	5,900.00-	352.73	4,973.15	113.37
364 Poles, Towers & Fixtures	18,754.03	601.64-	9,193.04	26,844.18-	501.25
365 Overhead Conductors & Dev	.00	.00	5,237.78	.00	5,237.78
367 Under. Conductors & Devic	3,484.61	6,219.53-	17,794.81	13,343.00-	1,716.89
369 Services	1,907.91	1,057.48-	11,638.22	11,243.42-	1,245.23
371 Install. on Cust. Premise	97.95-	5,121.48-	4,170.22	1,226.30	177.09
373 Street Light. & Signal Sy	402.83	824.65-	1,905.88	1,434.15-	49.91
D Dist (E/360-373,G/374-387)	25,138.92	19,724.78-	50,292.68	46,665.30-	9,041.52
G General (E,G/389-398)					
3922 Vehicles	24.37	10,325.00-	6.18	10,300.63	6.18
3941 Misc. Tools - Nonunitized	.00	1,000.00-	55.75	944.25	.00
3962 Power Operated Equipment	.00	24,200.00-	.00	21,200.00	3,000.00-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3974 Carrier Current Comm. Equ	.00	.00	.00	.00	.00
3975 Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976 Scada System	.00	.00	1,749.21	1,399.44-	349.77
G General (E,G/389-398)	24.37	35,525.00-	1,811.14	31,045.44	2,644.05-
S Steam Production (E/310-316					
311807 Structures & Improvements	805,920.65-	.00	4,098.61	545.49	801,276.55-
312820 Boiler Plant Equipment	22,156.23	179,752.60-	4,301.22	22,457.45-	175,752.60-
314820 Turbogenerator Units	.00	.00	.00	.00	.00
316820 Misc. Power Plant Equipme	.00	3,900.00-	.00	3,900.00	.00
S Steam Production (E/310-316	783,764.42-	183,652.60-	8,399.83	18,011.96-	977,029.15-
T Elec Transmission (350-358)					
353 Station Equipment	526.43	.00	412.24	888.67-	50.00
355 Poles & Fixtures	2,119.77-	749.63-	4,971.76	2,102.36-	.00
356 Overhead Conductor & Devi	.00	19,823.68-	9,824.60	9,999.08	.00
T Elec Transmission (350-358)	1,593.34-	20,573.31-	15,208.60	7,008.05	50.00

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Project No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
00001 Montana Dakota Utilities Co.					
MT Montana					
1 Electric					
T Elec Transmission (350-358)					
1 Electric	760,194.47-	259,475.69-	75,712.25	26,623.77-	970,581.68-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
376 Mains	88,422.60-	7.30	118,967.04	111,396.24-	80,844.50-
378 Meas. & Reg. Equip. - Gen	1,169.33	.00	2,533.74	3,185.10-	517.97
385 Ind. meas. & Reg. Station	.00	.00	832.98	.00	832.98
3863 CNG Demonstration	43.49	.00	1,642.53-	1,599.04	.00
3871 Cathodic Protection Equip	.00	.00	14.90	14.90-	.00
D Dist (E/360-373,G/374-387)	87,209.78-	7.30	120,706.13	112,997.20-	79,493.55-
G General (E,G/389-398)					
3890 Land and Land Rights	564.40	.00	.00	.00	564.40
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	100.00	26,175.00-	150.00-	26,225.00	.00
3941 Misc. Tools - Nonunitized	.00	100.00-	.00	100.00	.00
3943 Vehicle Maintenance Equip	.00	.00	.00	.00	.00
3961 Work Equipment Trailers	.00	39.95-	.00	39.95	.00
3962 Power Operated Equipment	.00	39,662.00-	.00	39,662.00	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	664.40	65,976.95-	150.00-	66,026.95	564.40
2 Natural Gas	86,545.38-	65,969.65-	120,556.13	46,970.25-	78,929.15-
3 Propane					
D Dist (E/360-373,G/374-387)					
376 Mains	317.86	.00	1.09	318.95-	.00
D Dist (E/360-373,G/374-387)	317.86	.00	1.09	318.95-	.00
G General (E,G/389-398)					
3922 Vehicles	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	.00	.00	.00
3 Propane	317.86	.00	1.09	318.95-	.00
MT Montana	846,379.25-	328,553.34-	196,269.47	70,847.71-	1,049,510.83-

Project	No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
ND	North Dakota					
0	Common Utility					
G	General (E,G/389-398)					
390	Structures & Improvements	43,198.90	.00	2,232.60-	40,398.90-	567.40
3911	Office Furniture & Equipm	948.00-	180.00-	.00	1,128.00	.00
3913	Personal Computer Equipme	.00	10,604.45-	.00	10,604.45	.00
3922	Vehicles	3,131.00-	55,482.48-	1,044.22	42,720.25	14,849.01-
3923	Aircraft	.00	388,081.65-	.00	388,081.65	.00
3941	Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3962	Power Operated Equipment	.00	95,000.00-	.00	95,000.00	.00
3971	Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3972	Mobile Radio Comm. Equipm	519.31	.00	62.73	582.04-	.00
398	Miscellaneous Equipment	.00	53.76-	.00	53.76	.00
G	General (E,G/389-398)	39,639.21	549,402.34-	1,125.65-	496,607.17	14,281.61-
0	Common Utility	39,639.21	549,402.34-	1,125.65-	496,607.17	14,281.61-
1	Electric					
D	Dist (E/360-373,G/374-387)					
3601	Land	1,265.97-	.00	.00	1,265.97	.00
362	Station Equipment	2,945.10-	2,535.59-	17,720.18-	34,451.46	11,250.59
364	Poles, Towers & Fixtures	1,895.67	16.92-	7,939.34	9,681.56-	136.53
365	Overhead Conductors & Dev	.00	2,114.85-	6,186.11	4,071.26-	.00
367	Under. Conductors & Devic	8,270.54	27,422.00-	65,851.21	49,030.64-	2,330.89-
369	Services	2,427.70	6,551.46-	23,320.80	16,676.58-	2,520.46
371	Install. on Cust. Premise	781.77	6,791.30-	6,381.98	1,778.52-	1,406.07-
373	Street Light. & Signal Sy	859.68	4,555.14-	11,527.16	7,562.77-	268.93
D	Dist (E/360-373,G/374-387)	10,024.29	49,987.26-	103,486.42	53,083.90-	10,439.55
G	General (E,G/389-398)					
390	Structures & Improvements	220,146.00-	97,561.71-	.00	97,061.71	220,646.00-
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3914	Prime/Sun Computers	.00	6,175.00-	.00	6,175.00	.00
3922	Vehicles	.00	9,912.00-	.00	9,912.00	.00
393	Stores Equipment	.00	1,500.00-	.00	1,500.00	.00
3941	Misc. Tools - Nonunitized	.00	2,500.00-	.00	.00	2,500.00-
3962	Power Operated Equipment	250.00-	44,800.00-	.00	45,050.00	.00
3971	Fixed Radio Comm. Equipme	.00	.00	32.41	32.41-	.00
3975	Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976	Scada System	21.25	5.70-	7,051.33	2,352.90-	4,713.98
G	General (E,G/389-398)	220,374.75-	162,454.41-	7,083.74	157,313.40	218,432.02-
O	Other Production (E/340-346					
341806	Structures & Improvements	2,487.25-	.00	.00	.00	2,487.25-
O	Other Production (E/340-346	2,487.25-	.00	.00	.00	2,487.25-

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Project	No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
S	Steam Production (E/310-316					
310804	Land and Land Rights-Beul	1,825,252.05-	.00	2,231.96	2,080.64-	1,825,100.73-
311807	Structures & Improvements	138,503.00-	.00	.00	.00	138,503.00-
311810	Structures & Improvements	.00	4,042.50-	1,370.37	.00	2,672.13-
311830	Structures & Improvements	.00	.00	.00	.00	.00
312805	Boiler Plant Equipment	1,692.92-	.00	2,069.82	2,080.65-	1,703.75-
312810	Boiler Plant Equipment	6,956.77	2,114.55-	37,455.91	40,679.02-	1,619.11
312830	Boiler Plant Equipment	2,701.96	1,430.00-	2,701.77	4,053.73-	80.00-
314810	Turbogenerator Units	.00	.00	99.54	99.54-	.00
314830	Turbogenerator Units	4,269.25	.00	.00	4,269.25-	.00
316810	Misc. Power Plant Equipme	.00	2,800.00-	300.00	2,500.00	.00
316830	Misc. Power Plant Equipme	26.25-	5,427.50-	3,983.25	1,354.00	116.50-
S	Steam Production (E/310-316	1,951,546.24-	15,814.55-	50,212.62	49,408.83-	1,966,557.00-
T	Elec Transmission (350-358)					
353	Station Equipment	312.64	.00	6,265.72	5,804.58-	773.78
355	Poles & Fixtures	40,546.56-	8,055.36-	22,036.38	168.00	26,397.54-
356	Overhead Conductor & Devi	4,240.93	18,568.67-	22,062.90	8,840.10-	1,104.94-
T	Elec Transmission (350-358)	35,992.99-	26,624.03-	50,365.00	14,476.68-	26,728.70-
1	Electric	2,200,376.94-	254,880.25-	211,147.78	40,343.99	2,203,765.42-
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
3741	Land	.00	.00	.00	.00	.00
376	Mains	26,143.38	109.69-	97,756.65	112,274.65-	11,515.69
378	Meas. & Reg. Equip. - Gen	2,724.36	.00	2,001.93	4,726.29-	.00
379	Meas. & Reg. Equip.-City	.00	.00	279.93	.00	279.93
381	Positive Meters	.00	.00	.00	580.00	.00
3871	Cathodic Protection Equip	.00	.00	29.81	29.81-	.00
D	Dist (E/360-373,G/374-387)	28,867.74	109.69-	100,068.32	116,450.75-	11,795.62
G	General (E,G/389-398)					
390	Structures & Improvements	320.00	.00	.00	320.00-	.00
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3922	Vehicles	9,858.90-	26,888.83-	300.00	36,445.83	1.90-
3942	Misc. Tools - Unitized	.00	.00	.00	.00	.00
3944	Vehicle Refueling Equipme	.00	.00	.00	.00	.00
395	Laboratory Equipment	.00	500.00-	.00	.00	500.00-
3961	Work Equipment Trailers	.00	.00	.00	.00	.00
3962	Power Operated Equipment	.00	152,561.85-	7.18	151,954.67	600.00-
3971	Fixed Radio Comm. Equipme	91.95	.00	.00	91.95-	.00
G	General (E,G/389-398)	9,446.95-	179,950.68-	307.18	187,988.55	1,101.90-

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Project No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
00001 Montana Dakota Utilities Co.					
ND North Dakota					
2 Natural Gas					
G General (E,G/389-398)					
2 Natural Gas	19,420.79	180,060.37-	100,375.50	71,537.80	10,693.72
ND North Dakota	2,141,316.94-	984,342.96-	310,397.63	608,488.96	2,207,353.31-
SD South Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	.00	800.00-	.00	800.00	.00
3972 Mobile Radio Comm. Equipm	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	800.00-	.00	800.00	.00
0 Common Utility	.00	800.00-	.00	800.00	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	.00	.00	.00	.00
364 Poles, Towers & Fixtures	.00	48.21-	4,496.69	4,448.48-	.00
365 Overhead Conductors & Dev	.00	.00	.00	.00	.00
367 Under. Conductors & Devic	1,352.23	3,080.42-	17,014.03	13,461.86-	1,823.98
369 Services	1,385.36	1,309.99-	8,871.70	7,991.30-	955.77
371 Install. on Cust. Premise	11.13	3,274.71-	3,931.03	375.31-	292.14
373 Street Light. & Signal Sy	538.04	601.22-	1,661.95	1,598.77-	.00
D Dist (E/360-373,G/374-387)	3,286.76	8,314.55-	35,975.40	27,875.72-	3,071.89
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	.00	.00	.00
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	.00	13,230.00-	900.00	12,330.00	.00
3962 Power Operated Equipment	.00	.00	.00	.00	.00
3976 Scada System	621.46	.00	317.26-	304.20-	.00
G General (E,G/389-398)	621.46	13,230.00-	582.74	12,025.80	.00
S Steam Production (E/310-316					
311814 Structures & Improvements	6,366.00-	.00	.00	.00	6,366.00-
311861 Structures & Improvements	.00	.00	.00	.00	.00
312861 Boiler Plant Equipment	.00	.00	65,262.50	65,262.50-	.00
316861 Misc. Power Plant Equipme	263.62-	1,068.04-	.00	1,331.66	.00

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Project No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
00001 Montana Dakota Utilities Co.					
SD South Dakota					
1 Electric					
S Steam Production (E/310-316					
S Steam Production (E/310-316	6,629.62-	1,068.04-	65,262.50	63,930.84-	6,366.00-
T Elec Transmission (350-358)					
353 Station Equipment	.00	.00	3,783.25	3,606.06-	177.19
355 Poles & Fixtures	.00	.00	.00	.00	.00
356 Overhead Conductor & Devi	1,759.94	17.72-	315.93	2,058.15-	.00
T Elec Transmission (350-358)	1,759.94	17.72-	4,099.18	5,664.21-	177.19
1 Electric	961.46-	22,630.31-	105,919.82	85,444.97-	3,116.92-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	480.00	.00	.00	480.00-	.00
375 Structures & Improvements	.00	.00	.00	.00	.00
376 Mains	12,211.22	.00	48,199.57	51,831.30-	8,579.49
378 Meas. & Reg. Equip. - Gen	172.64	1,198.53-	1,001.35	39.54	15.00
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
385 Ind. meas. & Reg. Station	.00	.00	.00	.00	.00
3863 CNG Demonstration	1,460.39-	577.10-	.00	2,037.49	.00
3871 Cathodic Protection Equip	.00	.00	50.00	.00	50.00
D Dist (E/360-373,G/374-387)	11,403.47	1,775.63-	49,250.92	50,234.27-	8,644.49
G General (E,G/389-398)					
390 Structures & Improvements	686.53	.00	.00	686.53-	.00
3911 Office Furniture & Equipm	5.00-	3,535.42-	.00	2,337.00	1,203.42-
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	.00	43,442.47-	1,041.97	40,220.70	2,179.80-
3941 Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3962 Power Operated Equipment	146.71	276,106.48-	.00	275,959.77	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3973 General Telephone Comm. E	.00	.00	.00	.00	.00
G General (E,G/389-398)	828.24	323,084.37-	1,041.97	317,830.94	3,383.22-
2 Natural Gas	12,231.71	324,860.00-	50,292.89	267,596.67	5,261.27
4 Non-utility					
D Dist (E/360-373,G/374-387)					
3871 Cathodic Protection Equip	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	.00	.00	.00	.00	.00

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Project No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
00001 Montana Dakota Utilities Co.					
SD South Dakota					
4 Non-utility					
D Dist (E/360-373,G/374-387)					
4 Non-utility	.00	.00	.00	.00	.00
SD South Dakota	11,270.25	348,290.31-	156,212.71	182,951.70	2,144.35
WY Wyoming					
0 Common Utility					
G General (E,G/389-398)					
3911 Office Furniture & Equipm	.00	88.00-	.00	88.00	.00
3922 Vehicles	.00	3,176.00-	.00	.00	3,176.00-
G General (E,G/389-398)	.00	3,264.00-	.00	88.00	3,176.00-
0 Common Utility	.00	3,264.00-	.00	88.00	3,176.00-
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	.00	.00	.00	.00
364 Poles, Towers & Fixtures	8,810.40	628.74-	6,207.48	13,664.14-	725.00
365 Overhead Conductors & Dev	.00	.00	6,102.30	6,102.30-	.00
367 Under. Conductors & Devic	2,819.49	3,309.79-	24,517.25	16,300.15-	7,726.80
369 Services	1,760.10	254.77-	6,015.01	6,701.38-	818.96
370 Meters	.00	.00	.00	.00	.00
371 Install. on Cust. Premise	402.71	373.11-	1,827.44	1,684.58-	172.46
373 Street Light. & Signal Sy	2,138.04	2,632.30-	592.31	14.92-	83.13
D Dist (E/360-373,G/374-387)	15,930.74	7,198.71-	45,261.79	44,467.47-	9,526.35
G General (E,G/389-398)					
3962 Power Operated Equipment	.00	.00	.00	.00	.00
3976 Scada System	.00	.00	398.50	398.50-	.00
G General (E,G/389-398)	.00	.00	398.50	398.50-	.00
T Elec Transmission (350-358)					
353 Station Equipment	.00	.00	.00	.00	.00
356 Overhead Conductor & Devi	.00	.00	.00	.00	.00
T Elec Transmission (350-358)	.00	.00	.00	.00	.00
1 Electric	15,930.74	7,198.71-	45,660.29	44,865.97-	9,526.35
2 Natural Gas					

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Project	No. and Description	RWIP Beginning Balance 1/1/98	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/98
D	Dist (E/360-373,G/374-387)					
3741	Land	.00	9,791.88-	635.00	9,156.88	.00
376	Mains	4,107.46	.00	21,616.63	22,965.37-	2,758.72
D	Dist (E/360-373,G/374-387)	4,107.46	9,791.88-	22,251.63	13,808.49-	2,758.72
G	General (E,G/389-398)					
390	Structures & Improvements	.00	.00	.00	.00	.00
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3921	Trailers	.00	.00	.00	.00	.00
3922	Vehicles	.00	6,553.00-	.00	4,553.00	2,000.00-
3941	Misc. Tools - Nonunitized	105.00-	.00	.00	105.00	.00
3944	Vehicle Refueling Equipme	.00	.00	1,609.55-	1,609.55	.00
3962	Power Operated Equipment	.00	1,900.00-	.00	1,900.00	.00
G	General (E,G/389-398)	105.00-	8,453.00-	1,609.55-	8,167.55	2,000.00-
2	Natural Gas	4,002.46	18,244.88-	20,642.08	5,640.94-	758.72
WY	Wyoming	19,933.20	28,707.59-	66,302.37	50,418.91-	7,109.07
00001	Montana Dakota Utilities Co.	2,959,184.61-	1,702,545.03-	729,616.74	674,612.19	3,258,080.71-

Project No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
00001 Montana Dakota Utilities Co.					
AS Allocated State					
1 Electric					
D Dist (E/360-373,G/374-387)					
368 Line Transformers	9,079.60-	4,389.34-	.00	10,903.76	2,565.18-
370 Meters	679.00	2,009.77-	.00	259.00-	1,589.77-
D Dist (E/360-373,G/374-387)	8,400.60-	6,399.11-	.00	10,644.76	4,154.95-
1 Electric	8,400.60-	6,399.11-	.00	10,644.76	4,154.95-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
381 Positive Meters	1,488.97-	5,207.09-	17.01-	1,587.77	5,125.30-
383 Service Regulators	701.19-	4,191.38-	1,692.15-	2,328.86	4,255.86-
D Dist (E/360-373,G/374-387)	2,190.16-	9,398.47-	1,709.16-	3,916.63	9,381.16-
2 Natural Gas	2,190.16-	9,398.47-	1,709.16-	3,916.63	9,381.16-
AS Allocated State	10,590.76-	15,797.58-	1,709.16-	14,561.39	13,536.11-
ER East River					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	120.77	84.53-	481.85	206.36-	311.73
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	120.77	84.53-	481.85	206.36-	311.73
G General (E,G/389-398)					
3962 Power Operated Equipment	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	.00	.00	.00
2 Natural Gas	120.77	84.53-	481.85	206.36-	311.73
ER East River	120.77	84.53-	481.85	206.36-	311.73
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
3890 Land and Land Rights	.00	23,453.89-	1,403.50	22,050.39	.00
390 Structures & Improvements	.00	23,000.00-	4,088.93	18,911.07	.00
3911 Office Furniture & Equipm	.00	140.00-	.00	140.00	.00

MDU Resources Group Inc.
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Project No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
00001 Montana Dakota Utilities Co.					
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	.00	16,021.00-	29.05	15,991.95	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	62,614.89-	5,521.48	57,093.41	.00
0 Common Utility	.00	62,614.89-	5,521.48	57,093.41	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	113.37	2,200.00-	.00	2,086.63	.00
364 Poles, Towers & Fixtures	501.25	.00	1,239.80	1,741.05-	.00
365 Overhead Conductors & Dev	5,237.78	2,959.00-	.00	2,278.78-	.00
367 Under. Conductors & Devic	1,716.89	38,107.30-	29,674.76	6,518.12-	13,233.77-
369 Services	1,245.23	3,944.95-	11,664.89	8,996.79-	31.62-
371 Install. on Cust. Premise	177.09	7,524.82-	4,903.69	1,787.06	656.98-
373 Street Light. & Signal Sy	49.91	5,940.80-	2,721.36	1,274.63-	4,444.16-
D Dist (E/360-373,G/374-387)	9,041.52	60,676.87-	50,204.50	16,935.68-	18,366.53-
G General (E,G/389-398)					
3922 Vehicles	6.18	1,700.00-	6.18-	1,700.00	.00
3941 Misc. Tools - Nonunitized	.00	1,000.00-	.00	1,000.00	.00
3962 Power Operated Equipment	3,000.00-	24,995.00-	449.31	26,545.69	1,000.00-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3974 Carrier Current Comm. Equ	.00	.00	.00	.00	.00
3975 Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976 Scada System	349.77	.00	738.43	1,088.20-	.00
G General (E,G/389-398)	2,644.05-	27,695.00-	1,181.56	28,157.49	1,000.00-
O Other Production (E/340-346					
344851 Generators	.00	1,701.00-	1,160.61	301.00	239.39-
344852 Generators	.00	.00	2,104.54	.00	2,104.54
O Other Production (E/340-346	.00	1,701.00-	3,265.15	301.00	1,865.15
S Steam Production (E/310-316					
311807 Structures & Improvements	801,276.55-	.00	5,349.16	5,182.23-	801,109.62-
312820 Boiler Plant Equipment	175,752.60-	575.61-	3,700.40	173,976.36	1,348.55
314820 Turbogenerator Units	.00	672,890.63-	98,800.00	.00	574,090.63-
316820 Misc. Power Plant Equipme	.00	.00	.00	.00	.00
S Steam Production (E/310-316	977,029.15-	673,466.24-	107,849.56	168,794.13	1,373,851.70-

Project No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
00001 Montana Dakota Utilities Co.					
MT Montana					
1 Electric					
T Elec Transmission (350-358)					
353 Station Equipment	50.00	.00	4,011.06	4,061.06-	.00
355 Poles & Fixtures	.00	.00	.00	.00	.00
356 Overhead Conductor & Devi	.00	222.25-	3,465.91	302.61-	2,941.05
T Elec Transmission (350-358)	50.00	222.25-	7,476.97	4,363.67-	2,941.05
1 Electric	970,581.68-	763,761.36-	169,977.74	175,953.27	1,388,412.03-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
376 Mains	80,844.50-	.00	145,851.10	139,822.34-	74,815.74-
378 Meas. & Reg. Equip. - Gen	517.97	.00	.00	517.97-	.00
385 Ind. meas. & Reg. Station	832.98	.00	.00	832.98-	.00
3863 CNG Demonstration	.00	.00	.00	.00	.00
3871 Cathodic Protection Equip	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	79,493.55-	.00	145,851.10	141,173.29-	74,815.74-
G General (E,G/389-398)					
3890 Land and Land Rights	564.40	.00	.00	.00	564.40
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	319.89-	.00	284.88	35.01-
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	.00	15,916.00-	.00	14,616.00	1,300.00-
3941 Misc. Tools - Nonunitized	.00	25.00-	.00	25.00	.00
3943 Vehicle Maintenance Equip	.00	.00	.00	.00	.00
3961 Work Equipment Trailers	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	335,581.20-	4,907.91	327,873.29	2,800.00-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	564.40	351,842.09-	4,907.91	342,799.17	3,570.61-
2 Natural Gas	78,929.15-	351,842.09-	150,759.01	201,625.88	78,386.35-
3 Propane					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	.00	.00	.00	.00	.00
G General (E,G/389-398)					
3922 Vehicles	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	.00	.00	.00

MDU Resources Group Inc.
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Project	No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
3	Propane	.00	.00	.00	.00	.00
MT	Montana	1,049,510.83-	1,178,218.34-	326,258.23	434,672.56	1,466,798.38-
ND	North Dakota					
0	Common Utility					
G	General (E,G/389-398)					
390	Structures & Improvements	567.40	7,685.00-	2,325.00	4,792.60	.00
3911	Office Furniture & Equipm	.00	2,748.00-	.00	2,036.86	711.14-
3913	Personal Computer Equipme	.00	2,290.00-	.00	2,290.00	.00
3922	Vehicles	14,849.01-	14,702.00-	85.12	23,365.89	6,100.00-
3923	Aircraft	.00	.00	.00	.00	.00
3941	Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3962	Power Operated Equipment	.00	.00	.00	.00	.00
3971	Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3972	Mobile Radio Comm. Equipm	.00	.00	.00	.00	.00
398	Miscellaneous Equipment	.00	.00	.00	.00	.00
G	General (E,G/389-398)	14,281.61-	27,425.00-	2,410.12	32,485.35	6,811.14-
I	Intangible (E,G/301,302,303					
303	Misc. Intangible Plant	.00	.00	5,245.00	5,245.00-	.00
I	Intangible (E,G/301,302,303	.00	.00	5,245.00	5,245.00-	.00
0	Common Utility	14,281.61-	27,425.00-	7,655.12	27,240.35	6,811.14-
1	Electric					
D	Dist (E/360-373,G/374-387)					
3601	Land	.00	.00	.00	.00	.00
362	Station Equipment	11,250.59	.00	2,840.57	13,316.38-	774.78
364	Poles, Towers & Fixtures	136.53	114.08-	20,191.96	16,621.82-	3,592.59
365	Overhead Conductors & Dev	.00	.00	.00	.00	.00
367	Under. Conductors & Devic	2,330.89-	13,104.00-	82,134.62	54,118.40-	12,581.33
369	Services	2,520.46	4,796.23-	24,781.15	18,857.89-	3,647.49
371	Install. on Cust. Premise	1,406.07-	7,158.35-	6,028.26	1,929.55	606.61-
373	Street Light. & Signal Sy	268.93	4,823.68-	12,785.52	7,732.13-	498.64
D	Dist (E/360-373,G/374-387)	10,439.55	29,996.34-	148,762.08	108,717.07-	20,488.22
G	General (E,G/389-398)					
390	Structures & Improvements	220,646.00-	.00	.00	.00	220,646.00-
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3914	Prime/Sun Computers	.00	626.23-	91.46	534.77	.00
3922	Vehicles	.00	15,015.00-	.00	14,803.00	212.00-
393	Stores Equipment	.00	.00	.00	.00	.00

MDU Resources Group Inc.
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Project No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
00001 Montana Dakota Utilities Co.					
ND North Dakota					
1 Electric					
G General (E,G/389-398)					
3941 Misc. Tools - Nonunitized	2,500.00-	249.88-	.00	2,749.88	.00
3962 Power Operated Equipment	.00	42,000.00-	.00	42,000.00	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3975 Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976 Scada System	4,713.98	.00	514.25	5,228.23-	.00
G General (E,G/389-398)	218,432.02-	57,891.11-	605.71	54,859.42	220,858.00-
O Other Production (E/340-346					
341806 Structures & Improvements	2,487.25-	.00	.00	.00	2,487.25-
O Other Production (E/340-346	2,487.25-	.00	.00	.00	2,487.25-
S Steam Production (E/310-316					
310804 Land and Land Rights-Beul	1,825,100.73-	.00	1,063.50	1,919.15-	1,825,956.38-
311807 Structures & Improvements	138,503.00-	.00	.00	.00	138,503.00-
311810 Structures & Improvements	2,672.13-	.00	6,894.01	3,345.30-	876.58
311830 Structures & Improvements	.00	.00	.00	.00	.00
312805 Boiler Plant Equipment	1,703.75-	.00	1,045.47	1,738.99-	2,397.27-
312810 Boiler Plant Equipment	1,619.11	.00	40,058.51	37,665.94-	4,011.68
312830 Boiler Plant Equipment	80.00-	153.25-	.00	233.25	.00
314810 Turbogenerator Units	.00	.00	3,795.82	703.31-	3,092.51
314830 Turbogenerator Units	.00	.00	.00	.00	.00
316810 Misc. Power Plant Equipme	.00	2,000.00-	.00	2,000.00	.00
316830 Misc. Power Plant Equipme	116.50-	7,198.61-	.00	116.50	7,198.61-
S Steam Production (E/310-316	1,966,557.00-	9,351.86-	52,857.31	43,022.94-	1,966,074.49-
T Elec Transmission (350-358)					
353 Station Equipment	773.78	.00	356.10	1,129.88-	.00
355 Poles & Fixtures	26,397.54-	36,260.01-	36,179.05	26,478.50	.00
356 Overhead Conductor & Devi	1,104.94-	1,267.16	18,046.27	12,727.84-	5,480.65
T Elec Transmission (350-358)	26,728.70-	34,992.85-	54,581.42	12,620.78	5,480.65
1 Electric	2,203,765.42-	132,232.16-	256,806.52	84,259.81-	2,163,450.87-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
376 Mains	11,515.69	784.17	103,971.37	85,322.81-	30,948.42
378 Meas. & Reg. Equip. - Gen	.00	.00	30.56	.00	30.56
379 Meas. & Reg. Equip.-City	279.93	.00	.00	279.93-	.00
381 Positive Meters	.00	.00	.00	.00	.00
3871 Cathodic Protection Equip	.00	.00	187.42	83.29-	104.13

Project No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
00001 Montana Dakota Utilities Co.					
ND North Dakota					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
D Dist (E/360-373,G/374-387)	11,795.62	784.17	104,189.35	85,686.03-	31,083.11
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	1.90-	30,756.00-	945.00	24,107.90	5,705.00-
3942 Misc. Tools - Unitized	.00	.00	.00	.00	.00
3944 Vehicle Refueling Equipme	.00	.00	.00	.00	.00
395 Laboratory Equipment	500.00-	.00	.00	.00	500.00-
3961 Work Equipment Trailers	.00	1,600.00-	.00	1,450.00	150.00-
3962 Power Operated Equipment	600.00-	453,602.50-	5,946.95	447,255.55	1,000.00-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	1,101.90-	485,958.50-	6,891.95	472,813.45	7,355.00-
2 Natural Gas	10,693.72	485,174.33-	111,081.30	387,127.42	23,728.11
ND North Dakota	2,207,353.31-	644,831.49-	375,542.94	330,107.96	2,146,533.90-
SD South Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	.00	4,000.00-	.00	4,000.00	.00
3972 Mobile Radio Comm. Equipm	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	4,000.00-	.00	4,000.00	.00
0 Common Utility	.00	4,000.00-	.00	4,000.00	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	.00	.00	.00	.00
364 Poles, Towers & Fixtures	.00	15.66-	5,463.83	4,891.89-	556.28
365 Overhead Conductors & Dev	.00	.00	.00	.00	.00
367 Under. Conductors & Devic	1,823.98	1,555.18-	15,273.96	13,012.42-	2,530.34
369 Services	955.77	1,170.42-	7,235.01	5,596.28-	1,424.08
371 Install. on Cust. Premise	292.14	408.23-	1,047.16	724.77-	206.30
373 Street Light. & Signal Sy	.00	1,629.72-	3,567.61	1,270.79-	667.10
D Dist (E/360-373,G/374-387)	3,071.89	4,779.21-	32,587.57	25,496.15-	5,384.10

Project No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
00001 Montana Dakota Utilities Co.					
SD South Dakota					
1 Electric					
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	.00	.00	.00
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	1,150.00-	.00	1,150.00	.00
3976 Scada System	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	1,150.00-	.00	1,150.00	.00
S Steam Production (E/310-316					
311814 Structures & Improvements	6,366.00-	.00	.00	.00	6,366.00-
311861 Structures & Improvements	.00	794.50-	.00	794.50	.00
312861 Boiler Plant Equipment	.00	48,241.20-	121,488.44	118,027.67-	44,780.43-
314861 Turbogenerator Units	.00	20,724.42-	12,090.81	8,633.61	.00
316861 Misc. Power Plant Equipme	.00	17.40-	7,491.00	7,473.60-	.00
S Steam Production (E/310-316	6,366.00-	69,777.52-	141,070.25	116,073.16-	51,146.43-
T Elec Transmission (350-358)					
353 Station Equipment	177.19	.00	.00	177.19-	.00
355 Poles & Fixtures	.00	.00	.00	.00	.00
356 Overhead Conductor & Devi	.00	91.30-	1,374.66	967.04-	316.32
T Elec Transmission (350-358)	177.19	91.30-	1,374.66	1,144.23-	316.32
1 Electric	3,116.92-	75,798.03-	175,032.48	141,563.54-	45,446.01-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
375 Structures & Improvements	.00	.00	.00	.00	.00
376 Mains	8,579.49	.00	26,036.76	28,189.29-	6,426.96
378 Meas. & Reg. Equip. - Gen	15.00	962.68-	7,365.69	5,164.80-	1,253.21
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
385 Ind. meas. & Reg. Station	.00	.00	.00	.00	.00
3863 CNG Demonstration	.00	.00	.00	.00	.00
3871 Cathodic Protection Equip	50.00	.00	.00	50.00-	.00
D Dist (E/360-373,G/374-387)	8,644.49	962.68-	33,402.45	33,404.09-	7,680.17
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	1,203.42-	65.00-	.00	1,268.42	.00
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	2,179.80-	14,713.97-	170.24	16,723.53	.00

Project No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
00001 Montana Dakota Utilities Co.					
SD South Dakota					
2 Natural Gas					
G General (E,G/389-398)					
3941 Misc. Tools - Nonunitized	.00	.00	18.79	.00	18.79
3943 Vehicle Maintenance Equip	.00	150.00-	.00	150.00	.00
3961 Work Equipment Trailers	.00	7,500.00-	.00	7,500.00	.00
3962 Power Operated Equipment	.00	433,610.00-	5,126.89	428,483.11	.00
3971 Fixed Radio Comm. Equipme	.00	250.00-	2,197.64	1,947.64-	.00
3973 General Telephone Comm. E	.00	.00	.00	.00	.00
G General (E,G/389-398)	3,383.22-	456,288.97-	7,513.56	452,177.42	18.79
2 Natural Gas	5,261.27	457,251.65-	40,916.01	418,773.33	7,698.96
4 Non-utility					
D Dist (E/360-373,G/374-387)					
3871 Cathodic Protection Equip	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	.00	.00	.00	.00	.00
4 Non-utility	.00	.00	.00	.00	.00
SD South Dakota	2,144.35	537,049.68-	215,948.49	281,209.79	37,747.05-
WY Wyoming					
0 Common Utility					
G General (E,G/389-398)					
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	3,176.00-	7,035.00-	.00	10,211.00	.00
G General (E,G/389-398)	3,176.00-	7,035.00-	.00	10,211.00	.00
0 Common Utility	3,176.00-	7,035.00-	.00	10,211.00	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	.00	187.35	.00	187.35
364 Poles, Towers & Fixtures	725.00	.00	10,527.00	9,052.00-	2,200.00
365 Overhead Conductors & Dev	.00	2,010.82-	.00	2,010.82	.00
367 Under. Conductors & Devic	7,726.80	3,465.21-	40,901.00	22,354.20-	22,808.39
369 Services	818.96	177.06-	5,266.29	3,678.77-	2,229.42
370 Meters	.00	.00	.00	.00	.00
371 Install. on Cust. Premise	172.46	1,472.35-	2,923.39	1,888.71-	265.21-
373 Street Light. & Signal Sy	83.13	.00	1,236.97	1,038.93-	281.17
D Dist (E/360-373,G/374-387)	9,526.35	7,125.44-	61,042.00	36,001.79-	27,441.12

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 1999

Project	No. and Description	RWIP Beginning Balance 1/1/99	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/99
G	General (E,G/389-398)					
3922	Vehicles	.00	6,350.00-	304.66-	6,654.66	.00
3962	Power Operated Equipment	.00	.00	.00	.00	.00
3976	Scada System	.00	.00	.00	.00	.00
G	General (E,G/389-398)	.00	6,350.00-	304.66-	6,654.66	.00
T	Elec Transmission (350-358)					
353	Station Equipment	.00	.00	.00	.00	.00
356	Overhead Conductor & Devi	.00	.00	1,563.00	.00	1,563.00
T	Elec Transmission (350-358)	.00	.00	1,563.00	.00	1,563.00
1	Electric	9,526.35	13,475.44-	62,300.34	29,347.13-	29,004.12
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
3741	Land	.00	.00	.00	.00	.00
376	Mains	2,758.72	.00	45,741.27	35,501.18-	12,998.81
D	Dist (E/360-373,G/374-387)	2,758.72	.00	45,741.27	35,501.18-	12,998.81
G	General (E,G/389-398)					
390	Structures & Improvements	.00	.00	.00	.00	.00
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3921	Trailers	.00	.00	.00	.00	.00
3922	Vehicles	2,000.00-	1,000.00-	.00	1,500.00	1,500.00-
3941	Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3944	Vehicle Refueling Equipme	.00	.00	.00	.00	.00
3962	Power Operated Equipment	.00	100,100.00-	1,070.85	99,029.15	.00
G	General (E,G/389-398)	2,000.00-	101,100.00-	1,070.85	100,529.15	1,500.00-
2	Natural Gas	758.72	101,100.00-	46,812.12	65,027.97	11,498.81
WY	Wyoming	7,109.07	121,610.44-	109,112.46	45,891.84	40,502.93
00001	Montana Dakota Utilities Co.	3,258,080.71-	2,497,592.06-	1,025,634.81	1,106,237.18	3,623,800.78-

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 2000

Project No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001 Montana Dakota Utilities Co.					
AS Allocated State					
1 Electric					
D Dist (E/360-373,G/374-387)					
368 Line Transformers	2,565.18-	3,883.35-	.00	2,565.18	3,883.35-
370 Meters	1,589.77-	.00	.00	1,589.77	.00
D Dist (E/360-373,G/374-387)	4,154.95-	3,883.35-	.00	4,154.95	3,883.35-
1 Electric	4,154.95-	3,883.35-	.00	4,154.95	3,883.35-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
381 Positive Meters	5,125.30-	8,133.00-	121.91	3,871.99-	622.10-
383 Service Regulators	4,255.86-	2,151.92-	.00	4,994.14	1,413.64-
D Dist (E/360-373,G/374-387)	9,381.16-	10,284.92-	121.91	1,122.15	2,035.74-
2 Natural Gas	9,381.16-	10,284.92-	121.91	1,122.15	2,035.74-
AS Allocated State	13,536.11-	14,168.27-	121.91	5,277.10	5,919.09-
ER East River					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	311.73	40.24-	889.71	727.50-	433.70
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	311.73	40.24-	889.71	727.50-	433.70
G General (E,G/389-398)					
3922 Vehicles	.00	9,542.00-	70.88	9,471.12	.00
3962 Power Operated Equipment	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	9,542.00-	70.88	9,471.12	.00
2 Natural Gas	311.73	9,582.24-	960.59	8,743.62	433.70
ER East River	311.73	9,582.24-	960.59	8,743.62	433.70
MN Minnesota					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	.00	17,400.97	.00	17,400.97
378 Meas. & Reg. Equip. - Gen	.00	.00	28.58	.00	28.58

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 2000

Project No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001 Montana Dakota Utilities Co.					
MN Minnesota					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
381 Positive Meters	.00	.00	4,602.51	.00	4,602.51
3871 Cathodic Protection Equip	.00	.00	25.02	.00	25.02
D Dist (E/360-373,G/374-387)	.00	.00	22,057.08	.00	22,057.08
2 Natural Gas	.00	.00	22,057.08	.00	22,057.08
MN Minnesota	.00	.00	22,057.08	.00	22,057.08
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	.00	.00	.00
390 Structures & Improvements	.00	.00	1,000.00-	1,000.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	.00	10,851.00-	.00	10,851.00	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	10,851.00-	1,000.00-	11,851.00	.00
0 Common Utility	.00	10,851.00-	1,000.00-	11,851.00	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	.00	.00	.00	.00
364 Poles, Towers & Fixtures	.00	.00	.00	.00	.00
365 Overhead Conductors & Dev	.00	.00	.00	.00	.00
367 Under. Conductors & Devic	13,233.77-	6,573.33-	28,732.49	3,027.15-	5,898.24
369 Services	31.62-	499.64-	13,743.72	11,719.53-	1,492.93
371 Install. on Cust. Premise	656.98-	2,566.06-	4,289.80	458.97-	607.79
373 Street Light. & Signal Sy	4,444.16-	356.46-	2,204.27	3,169.60	573.25
D Dist (E/360-373,G/374-387)	18,366.53-	9,995.49-	48,970.28	12,036.05-	8,572.21
G General (E,G/389-398)					
3922 Vehicles	.00	9,261.00-	.00	9,211.00	50.00-
3941 Misc. Tools :- Nonunitized	.00	.00	.00	.00	.00
3962 Power Operated Equipment	1,000.00-	12,000.00-	468.75	12,531.25	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3974 Carrier Current Comm. Equ	.00	.00	.00	.00	.00
3975 Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976 Scada System	.00	.00	.00	.00	.00

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 2000

Project No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001 Montana Dakota Utilities Co.					
MT Montana					
1 Electric					
G General (E,G/389-398)					
G General (E,G/389-398)	1,000.00-	21,261.00-	468.75	21,742.25	50.00-
O Other Production (E/340-346					
344851 Generators	239.39-	400.00-	.00	639.39	.00
344852 Generators	2,104.54	.00	.00	2,104.54-	.00
346851 Misc. Power Plant Equipme	.00	4,000.00-	.00	4,000.00	.00
346852 Misc. Power Plant Equipme	.00	1,500.00-	.00	1,500.00	.00
O Other Production (E/340-346	1,865.15	5,900.00-	.00	4,034.85	.00
S Steam Production (E/310-316					
311807 Structures & Improvements	801,109.62-	.00	2,647.88	2,818.94-	801,280.68-
311820 Structures & Improvements	.00	.00	6,000.00	6,000.00-	.00
312820 Boiler Plant Equipment	1,348.55	.00	1,742.46	3,091.01-	.00
314820 Turbogenerator Units	574,090.63-	47,206.99	.00	526,883.64	.00
316820 Misc. Power Plant Equipme	.00	900.00-	.00	900.00	.00
S Steam Production (E/310-316	1,373,851.70-	46,306.99	10,390.34	515,873.69	801,280.68-
T Elec Transmission (350-358)					
353 Station Equipment	.00	.00	.00	.00	.00
355 Poles & Fixtures	.00	.00	154.84	.00	154.84
356 Overhead Conductor & Devi	2,941.05	54.02-	561.64	2,941.05-	507.62
T Elec Transmission (350-358)	2,941.05	54.02-	716.48	2,941.05-	662.46
1 Electric	1,388,412.03-	9,096.48	60,545.85	526,673.69	792,096.01-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
376 Mains	74,815.74-	.00	115,002.71	106,119.57-	65,932.60-
378 Meas. & Reg. Equip. - Gen	.00	.00	3,306.92	1,410.83-	1,896.09
379 Meas. & Reg. Equip.-City	.00	175.00-	3,278.61	.00	3,103.61
385 Ind. meas. & Reg. Station	.00	.00	.00	.00	.00
3863 CNG Demonstration	.00	.00	.00	.00	.00
3871 Cathodic Protection Equip	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	74,815.74-	175.00-	121,588.24	107,530.40-	60,932.90-
G General (E,G/389-398)					
3890 Land and Land Rights	564.40	.00	.00	564.40-	.00
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	35.01-	193.51-	.00	228.52	.00

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
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Project No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001 Montana Dakota Utilities Co.					
MT Montana					
2 Natural Gas					
G General (E,G/389-398)					
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	1,300.00-	48,433.37-	251.76	39,263.61	10,218.00-
3941 Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3943 Vehicle Maintenance Equip	.00	.00	.00	.00	.00
3961 Work Equipment Trailers	.00	.00	.00	.00	.00
3962 Power Operated Equipment	2,800.00-	55,331.15-	.00	57,481.15	650.00-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	3,570.61-	103,958.03-	251.76	96,408.88	10,868.00-
2 Natural Gas	78,386.35-	104,133.03-	121,840.00	11,121.52-	71,800.90-
3 Propane					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	.00	.00	.00	.00	.00
G General (E,G/389-398)					
3922 Vehicles	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	.00	.00	.00
3 Propane	.00	.00	.00	.00	.00
MT Montana	1,466,798.38-	105,887.55-	181,385.85	527,403.17	863,896.91-
ND North Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	10,283.75-	31,977.70	20,309.20-	1,384.75
3911 Office Furniture & Equipm	711.14-	2,224.83-	.00	1,602.76	1,333.21-
3912 AS 400/Honeywell/CIS Equi	.00	800.00-	698.54	101.46	.00
3913 Personal Computer Equipme	.00	865.00-	.00	700.00	165.00-
3922 Vehicles	6,100.00-	72,329.00-	.00	69,114.00	9,315.00-
3923 Aircraft	.00	.00	.00	.00	.00
3941 Misc. Tools - Nonunitized	.00	45.00-	.00	45.00	.00
3962 Power Operated Equipment	.00	.00	.00	.00	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3972 Mobile Radio Comm. Equipm	.00	.00	.00	.00	.00
3973 General Telephone Comm. E	.00	4,320.00-	42.60	4,277.40	.00
3978 Network Equipment	.00	.00	600.00	600.00-	.00
398 Miscellaneous Equipment	.00	.00	.00	.00	.00

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
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As of December 31, 2000

Project	No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001	Montana Dakota Utilities Co.					
ND	North Dakota					
0	Common Utility					
G	General (E,G/389-398)					
G	General (E,G/389-398)	6,811.14-	90,867.58-	33,318.84	54,931.42	9,428.46-
I	Intangible (E,G/301,302,303					
303	Misc. Intangible Plant	.00	.00	.00	.00	.00
I	Intangible (E,G/301,302,303	.00	.00	.00	.00	.00
0	Common Utility	6,811.14-	90,867.58-	33,318.84	54,931.42	9,428.46-
1	Electric					
D	Dist (E/360-373,G/374-387)					
3601	Land	.00	1.00-	.00	1.00	.00
362	Station Equipment	774.78	.00	85.98	860.76-	.00
364	Poles, Towers & Fixtures	3,592.59	.00	8,623.28	8,380.08-	3,835.79
365	Overhead Conductors & Dev	.00	1,340.26-	4,742.99	.00	3,402.73
367	Under. Conductors & Devic	12,581.33	20,096.31-	98,649.27	80,102.25-	11,032.04
369	Services	3,647.49	3,554.25-	21,211.45	17,743.36-	3,561.33
371	Install. on Cust. Premise	606.61-	3,397.18-	4,186.27	3.71	186.19
373	Street Light. & Signal Sy	498.64	1,042.89-	11,258.22	9,634.75-	1,079.22
D	Dist (E/360-373,G/374-387)	20,488.22	29,431.89-	148,757.46	116,716.49-	23,097.30
G	General (E,G/389-398)					
390	Structures & Improvements	220,646.00-	.00	.00	.00	220,646.00-
3911	Office Furniture & Equipm	.00	100.00-	.00	100.00	.00
3914	Prime/Sun Computers	.00	.00	.00	.00	.00
3915	Other Computer Equipment	.00	.00	32.63	32.63-	.00
3922	Vehicles	212.00-	23,212.55-	1.87-	20,424.55	3,001.87-
393	Stores Equipment	.00	.00	.00	.00	.00
3941	Misc. Tools - Nonunitized	.00	2,960.00-	.00	.00	2,960.00-
3962	Power Operated Equipment	.00	35,000.00-	419.83	419.83-	35,000.00-
3971	Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3975	Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976	Scada System	.00	.00	.00	.00	.00
G	General (E,G/389-398)	220,858.00-	61,272.55-	450.59	20,072.09	261,607.87-
O	Other Production (E/340-346					
341806	Structures & Improvements	2,487.25-	.00	.00	.00	2,487.25-
O	Other Production (E/340-346	2,487.25-	.00	.00	.00	2,487.25-
S	Steam Production (E/310-316					
310804	Land and Land Rights-Beul	1,825,956.38-	.00	368.93	409.02-	1,825,996.47-

Project	No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001	Montana Dakota Utilities Co.					
ND	North Dakota					
1	Electric					
S	Steam Production (E/310-316					
311807	Structures & Improvements	138,503.00-	.00	.00	.00	138,503.00-
311810	Structures & Improvements	876.58	.00	.00	876.58-	.00
311830	Structures & Improvements	.00	.00	1,500.00	1,500.00-	.00
312805	Boiler Plant Equipment	2,397.27-	.00	1,469.51	409.00-	1,336.76-
312810	Boiler Plant Equipment	4,011.68	.00	42,869.60	44,031.39-	2,849.89
312830	Boiler Plant Equipment	.00	250.00-	26,648.59	23,552.46-	2,846.13
314810	Turbogenerator Units	3,092.51	930,300.00-	4,826.86	7,919.37-	930,300.00-
314830	Turbogenerator Units	.00	.00	.00	.00	.00
316810	Misc. Power Plant Equipme	.00	1,808.75-	472.93	1,666.85	331.03
316830	Misc. Power Plant Equipme	7,198.61-	518.43-	.00	7,198.61	518.43-
S	Steam Production (E/310-316	1,966,074.49-	932,877.18-	78,156.42	69,832.36-	2,890,627.61-
T	Elec Transmission (350-358)					
353	Station Equipment	.00	402,831.00-	22,033.72	21,075.98-	401,873.26-
355	Poles & Fixtures	.00	7,456.78-	11,948.10	4,491.32-	.00
356	Overhead Conductor & Devi	5,480.65	2,519.03-	12,060.13	14,668.19-	353.56
T	Elec Transmission (350-358)	5,480.65	412,806.81-	46,041.95	40,235.49-	401,519.70-
1	Electric	2,163,450.87-	1,436,388.43-	273,406.42	206,712.25-	3,533,145.13-
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
3741	Land	.00	.00	.00	.00	.00
376	Mains	30,948.42	662.32-	66,947.14	85,097.25-	12,135.99
378	Meas. & Reg. Equip. - Gen	30.56	.00	428.22	261.94-	196.84
379	Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
381	Positive Meters	.00	.00	146.75	.00	146.75
3871	Cathodic Protection Equip	104.13	.00	.00	104.13-	.00
D	Dist (E/360-373,G/374-387)	31,083.11	662.32-	67,522.11	85,463.32-	12,479.58
G	General (E,G/389-398)					
390	Structures & Improvements	.00	.00	.00	.00	.00
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3922	Vehicles	5,705.00-	25,817.00-	7.55	28,688.45	2,826.00-
3942	Misc. Tools - Unitized	.00	.00	.00	.00	.00
3944	Vehicle Refueling Equipme	.00	.00	.00	.00	.00
395	Laboratory Equipment	500.00-	.00	.00	.00	500.00-
3961	Work Equipment Trailers	150.00-	250.00-	.00	400.00	.00
3962	Power Operated Equipment	1,000.00-	163,552.50-	.00	164,552.50	.00
3971	Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G	General (E,G/389-398)	7,355.00-	189,619.50-	7.55	193,640.95	3,326.00-

Project No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001 Montana Dakota Utilities Co.					
ND North Dakota					
2 Natural Gas					
G General (E,G/389-398)					
2 Natural Gas	23,728.11	190,281.82-	67,529.66	108,177.63	9,153.58
4 Non-utility					
G General (E,G/389-398)					
3890 Land and Land Rights	.00	46,500.00-	418.00	46,082.00	.00
G General (E,G/389-398)	.00	46,500.00-	418.00	46,082.00	.00
4 Non-utility	.00	46,500.00-	418.00	46,082.00	.00
ND North Dakota	2,146,533.90-	1,764,037.83-	374,672.92	2,478.80	3,533,420.01-
SD South Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	1,900.00	1,900.00-	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	.00	.00	.00	.00	.00
3972 Mobile Radio Comm. Equipm	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	1,900.00	1,900.00-	.00
0 Common Utility	.00	.00	1,900.00	1,900.00-	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	.00	.00	.00	.00
364 Poles, Towers & Fixtures	556.28	6.80-	1,056.89	1,606.37-	.00
365 Overhead Conductors & Dev	.00	.00	.00	.00	.00
367 Under. Conductors & Devic	2,530.34	944.67-	16,417.35	13,579.01-	4,424.01
369 Services	1,424.08	1,452.71-	9,304.26	7,902.17-	1,373.46
371 Install. on Cust. Premise	206.30	33.60-	1,060.63	1,126.00-	107.33
373 Street Light. & Signal Sy	667.10	577.24-	2,407.72	2,302.02-	195.56
D Dist (E/360-373,G/374-387)	5,384.10	3,015.02-	30,246.85	26,515.57-	6,100.36
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	.00	.00	.00
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	.00	10,000.00-	.00	5,500.00	4,500.00-
3962 Power Operated Equipment	.00	.00	.00	.00	.00

MDU Resources Group Inc.
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Project No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001 Montana Dakota Utilities Co.					
SD South Dakota					
1 Electric					
G General (E,G/389-398)					
3976 Scada System	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	10,000.00-	.00	5,500.00	4,500.00-
S Steam Production (E/310-316					
311814 Structures & Improvements	6,366.00-	.00	.00	.00	6,366.00-
311861 Structures & Improvements	.00	.00	.00	.00	.00
312861 Boiler Plant Equipment	44,780.43-	.00	9,415.20	35,564.23	199.00
314861 Turbogenerator Units	.00	.00	.00	.00	.00
316861 Misc. Power Plant Equipme	.00	2,247.60-	.00	1,952.50	295.10-
S Steam Production (E/310-316	51,146.43-	2,247.60-	9,415.20	37,516.73	6,462.10-
T Elec Transmission (350-358)					
3502 Rights of Way	.00	.00	1,042.17	.00	1,042.17
353 Station Equipment	.00	.00	.00	.00	.00
355 Poles & Fixtures	.00	809.55-	5,910.10	.00	5,100.55
356 Overhead Conductor & Devi	316.32	138.93-	967.12	361.83-	782.68
T Elec Transmission (350-358)	316.32	948.48-	7,919.39	361.83-	6,925.40
1 Electric	45,446.01-	16,211.10-	47,581.44	16,139.33	2,063.66
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
375 Structures & Improvements	.00	.00	.00	.00	.00
376 Mains	6,426.96	.00	39,627.25	40,409.30-	5,644.91
378 Meas. & Reg. Equip. - Gen	1,253.21	1,609.66-	2,612.79	2,515.00-	258.66-
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
385 Ind. meas. & Reg. Station	.00	.00	.00	.00	.00
3863 CNG Demonstration	.00	.00	.00	.00	.00
3871 Cathodic Protection Equip	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	7,680.17	1,609.66-	42,240.04	42,924.30-	5,386.25
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	.00	45,737.59-	464.61	45,272.98	.00
3941 Misc. Tools - Nonunitized	18.79	3,240.00-	18.79-	3,240.00	.00
3943 Vehicle Maintenance Equip	.00	.00	.00	.00	.00
3961 Work Equipment Trailers	.00	50.00-	.00	50.00	.00
3962 Power Operated Equipment	.00	247,873.36-	.00	247,873.36	.00

Project No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001 Montana Dakota Utilities Co.					
SD South Dakota					
2 Natural Gas					
G General (E,G/389-398)					
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3973 General Telephone Comm. E	.00	.00	.00	.00	.00
G General (E,G/389-398)	18.79	296,900.95-	445.82	296,436.34	.00
2 Natural Gas	7,698.96	298,510.61-	42,685.86	253,512.04	5,386.25
4 Non-utility					
D Dist (E/360-373,G/374-387)					
3871 Cathodic Protection Equip	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	.00	.00	.00	.00	.00
4 Non-utility	.00	.00	.00	.00	.00
SD South Dakota	37,747.05-	314,721.71-	92,167.30	267,751.37	7,449.91
WY Wyoming					
0 Common Utility					
G General (E,G/389-398)					
3911 Office Furniture & Equipm	.00	404.24-	.00	404.24	.00
3922 Vehicles	.00	5,700.00-	.00	4,500.00	1,200.00-
G General (E,G/389-398)	.00	6,104.24-	.00	4,904.24	1,200.00-
0 Common Utility	.00	6,104.24-	.00	4,904.24	1,200.00-
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	187.35	.00	.00	187.35-	.00
364 Poles, Towers & Fixtures	2,200.00	76.02-	1,915.96	3,582.58-	457.36
365 Overhead Conductors & Dev	.00	.00	.00	.00	.00
367 Under. Conductors & Devic	22,808.39	1,433.23-	22,489.60	31,223.14-	12,641.62
369 Services	2,229.42	298.56-	4,655.78	5,071.16-	1,515.48
370 Meters	.00	.00	.00	.00	.00
371 Install. on Cust. Premise	265.21-	2,623.87-	2,805.35	1,071.59	987.86
373 Street Light. & Signal Sy	281.17	130.65-	4,156.52	1,550.38-	2,756.66
D Dist (E/360-373,G/374-387)	27,441.12	4,562.33-	36,023.21	40,543.02-	18,358.98
G General (E,G/389-398)					
3922 Vehicles	.00	.00	.00	.00	.00

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Project No. and Description	RWIP Beginning Balance 1/1/00	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/00
00001 Montana Dakota Utilities Co.					
WY Wyoming					
1 Electric					
G General (E,G/389-398)					
3962 Power Operated Equipment	.00	16,000.00-	.00	.00	16,000.00-
3976 Scada System	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	16,000.00-	.00	.00	16,000.00-
T Elec Transmission (350-358)					
353 Station Equipment	.00	.00	.00	.00	.00
356 Overhead Conductor & Devi	1,563.00	.00	.00	1,563.00-	.00
T Elec Transmission (350-358)	1,563.00	.00	.00	1,563.00-	.00
1 Electric	29,004.12	20,562.33-	36,023.21	42,106.02-	2,358.98
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
376 Mains	12,998.81	.00	27,836.41	32,315.44-	8,519.78
378 Meas. & Reg. Equip. - Gen	.00	10.00-	.00	10.00	.00
D Dist (E/360-373,G/374-387)	12,998.81	10.00-	27,836.41	32,305.44-	8,519.78
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	1,500.00-	.00	.00	1,500.00	.00
3941 Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3944 Vehicle Refueling Equipme	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	736.00-	.00	736.00	.00
G General (E,G/389-398)	1,500.00-	736.00-	.00	2,236.00	.00
2 Natural Gas	11,498.81	746.00-	27,836.41	30,069.44-	8,519.78
WY Wyoming	40,502.93	27,412.57-	63,859.62	67,271.22-	9,678.76
00001 Montana Dakota Utilities Co.	3,623,800.78-	2,235,810.17-	735,225.27	744,382.84	4,363,616.56-

Project No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
00001 Montana Dakota Utilities Co.					
AS Allocated State					
1 Electric					
D Dist (E/360-373,G/374-387)					
368 Line Transformers	3,883.35-	2,421.71-	41,433.37	25,854.34-	9,273.97
370 Meters	.00	.00	27,138.18	24,234.18-	2,904.00
D Dist (E/360-373,G/374-387)	3,883.35-	2,421.71-	68,571.55	50,088.52-	12,177.97
1 Electric	3,883.35-	2,421.71-	68,571.55	50,088.52-	12,177.97
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	18,899.34-	.00	.00	18,899.34-
381 Positive Meters	622.10-	2,383.57-	92,023.61	89,170.80-	152.86-
383 Service Regulators	1,413.64-	724.74-	.00	1,874.12	264.26-
D Dist (E/360-373,G/374-387)	2,035.74-	22,007.65-	92,023.61	87,296.68-	19,316.46-
2 Natural Gas	2,035.74-	22,007.65-	92,023.61	87,296.68-	19,316.46-
AS Allocated State	5,919.09-	24,429.36-	160,595.16	137,385.20-	7,138.49-
ER East River					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	433.70	58.93-	1,175.30	1,550.07-	.00
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	433.70	58.93-	1,175.30	1,550.07-	.00
G General (E,G/389-398)					
3922 Vehicles	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	66,600.00-	81.26	66,518.74	.00
G General (E,G/389-398)	.00	66,600.00-	81.26	66,518.74	.00
2 Natural Gas	433.70	66,658.93-	1,256.56	64,968.67	.00
ER East River	433.70	66,658.93-	1,256.56	64,968.67	.00
MN Minnesota					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
376 Mains	17,400.97	.00	21,813.74	35,400.16-	3,814.55

Project No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
00001 Montana Dakota Utilities Co.					
MN Minnesota					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
378 Meas. & Reg. Equip. - Gen	28.58	.00	28.58-	.00	.00
381 Positive Meters	4,602.51	.00	115.54-	4,480.16-	6.81
3871 Cathodic Protection Equip	25.02	.00	25.02-	.00	.00
D Dist (E/360-373,G/374-387)	22,057.08	.00	21,644.60	39,880.32-	3,821.36
G General (E,G/389-398)					
3911 Office Furniture & Equipm	.00	600.00-	.00	600.00	.00
3913 Personal Computer Equipme	.00	400.00-	.00	400.00	.00
3922 Vehicles	.00	31,555.00-	.00	31,555.00	.00
3962 Power Operated Equipment	.00	6,500.00-	227.50	6,272.50	.00
G General (E,G/389-398)	.00	39,055.00-	227.50	38,827.50	.00
2 Natural Gas	22,057.08	39,055.00-	21,872.10	1,052.82-	3,821.36
MN Minnesota	22,057.08	39,055.00-	21,872.10	1,052.82-	3,821.36
MT Montana					
0 Common Utility					
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	.00	.00	.00
390 Structures & Improvements	.00	.00	3,651.35	3,651.35-	.00
3911 Office Furniture & Equipm	.00	100.00-	.00	100.00	.00
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	.00	31,050.96-	.00	31,688.30	637.34
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	31,150.96-	3,651.35	28,136.95	637.34
0 Common Utility	.00	31,150.96-	3,651.35	28,136.95	637.34
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	.00	2,493.11	2,493.11-	.00
364 Poles, Towers & Fixtures	.00	.00	164.32	164.32-	.00
365 Overhead Conductors & Dev	.00	.00	.00	.00	.00
367 Under. Conductors & Devic	5,898.24	2,838.01-	16,505.48	16,753.73-	2,811.98
369 Services	1,492.93	131.23-	10,460.96	11,132.05-	690.61
371 Install. on Cust. Premise	607.79	3,554.41-	3,220.16	800.37-	526.83-
373 Street Light. & Signal Sy	573.25	2,223.58-	5,587.03	1,639.97-	2,296.73
D Dist (E/360-373,G/374-387)	8,572.21	8,747.23-	38,431.06	32,983.55-	5,272.49

MDU Resources Group Inc.
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Project No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
00001 Montana Dakota Utilities Co.					
MT Montana					
1 Electric					
G General (E,G/389-398)					
3922 Vehicles	50.00-	24,952.89-	.00	16,802.89	8,200.00-
3941 Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	26,570.00-	200.00	25,370.00	1,000.00-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3974 Carrier Current Comm. Equ	.00	.00	.00	.00	.00
3975 Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976 Scada System	.00	.00	.00	.00	.00
G General (E,G/389-398)	50.00-	51,522.89-	200.00	42,172.89	9,200.00-
O Other Production (E/340-346					
344851 Generators	.00	10,250.00-	546.80	9,703.20	.00
344852 Generators	.00	2,505.00-	.00	2,505.00	.00
346851 Misc. Power Plant Equipme	.00	3,800.00-	.00	.00	3,800.00-
346852 Misc. Power Plant Equipme	.00	300.00-	.00	.00	300.00-
O Other Production (E/340-346	.00	16,855.00-	546.80	12,208.20	4,100.00-
S Steam Production (E/310-316					
311807 Structures & Improvements	801,280.68-	.00	17,546.29	1,155.29-	784,889.68-
311820 Structures & Improvements	.00	.00	.00	.00	.00
312820 Boiler Plant Equipment	.00	1,200.00-	.00	.00	1,200.00-
314820 Turbogenerator Units	.00	.00	.00	.00	.00
316820 Misc. Power Plant Equipme	.00	7,375.00-	.00	1,500.00	5,875.00-
S Steam Production (E/310-316	801,280.68-	8,575.00-	17,546.29	344.71	791,964.68-
T Elec Transmission (350-358)					
353 Station Equipment	.00	6,275.74-	5,304.36	5,367.36-	6,338.74-
355 Poles & Fixtures	154.84	4,280.04-	4,125.20	.00	.00
356 Overhead Conductor & Devi	507.62	323.83-	5,562.63	714.92-	5,031.50
T Elec Transmission (350-358)	662.46	10,879.61-	14,992.19	6,082.28-	1,307.24-
1 Electric	792,096.01-	96,579.73-	71,716.34	15,659.97	801,299.43-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
376 Mains	65,932.60-	.00	109,500.78	115,424.57-	71,856.39-
378 Meas. & Reg. Equip. - Gen	1,896.09	.00	269.08	1,896.09-	269.08
379 Meas. & Reg. Equip.-City	3,103.61	.00	.00	3,103.61-	.00
385 Ind. meas. & Reg. Station	.00	.00	.00	.00	.00
3863 CNG Demonstration	.00	.00	.00	.00	.00
3871 Cathodic Protection Equip	.00	.00	50.83	.00	50.83

Project No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
00001 Montana Dakota Utilities Co.					
MT Montana					
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
D Dist (E/360-373,G/374-387)	60,932.90-	.00	109,820.69	120,424.27-	71,536.48-
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	.00	.00	.00
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	94.25-	.00	94.25	.00
3921 Trailers	.00	.00	.00	.00	.00
3922 Vehicles	10,218.00-	44,100.00-	.00	30,488.00	23,830.00-
3941 Misc. Tools - Nonunitized	.00	200.00-	.00	200.00	.00
3943 Vehicle Maintenance Equip	.00	.00	.00	.00	.00
3961 Work Equipment Trailers	.00	1,100.00-	.00	1,100.00	.00
3962 Power Operated Equipment	650.00-	302,411.00-	518.13	301,889.87	653.00-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
G General (E,G/389-398)	10,868.00-	347,905.25-	518.13	333,772.12	24,483.00-
2 Natural Gas	71,800.90-	347,905.25-	110,338.82	213,347.85	96,019.48-
3 Propane					
D Dist (E/360-373,G/374-387)					
376 Mains	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	.00	.00	.00	.00	.00
G General (E,G/389-398)					
3922 Vehicles	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	.00	.00	.00
3 Propane	.00	.00	.00	.00	.00
MT Montana	863,896.91-	475,635.94-	185,706.51	257,144.77	896,681.57-
ND North Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	1,384.75	4,593,548.51-	16,640.65	4,582,481.11	6,958.00
3911 Office Furniture & Equipm	1,333.21-	1,479.07-	.00	2,812.28	.00
3912 AS 400/Honeywell/CIS Equi	.00	.00	.00	.00	.00
3913 Personal Computer Equipme	165.00-	165.00	.00	.00	.00
3922 Vehicles	9,315.00-	310,814.57-	.00	85,922.00	234,207.57-
3923 Aircraft	.00	.00	.00	.00	.00

Project No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
00001 Montana Dakota Utilities Co.					
ND North Dakota					
0 Common Utility					
G General (E,G/389-398)					
3941 Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	.00	.00	.00	.00
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3972 Mobile Radio Comm. Equipm	.00	.00	.00	.00	.00
3973 General Telephone Comm. E	.00	.00	.00	.00	.00
3978 Network Equipment	.00	.00	.00	.00	.00
398 Miscellaneous Equipment	.00	.00	.00	.00	.00
G General (E,G/389-398)	9,428.46-	4,905,677.15-	16,640.65	4,671,215.39	227,249.57-
I Intangible (E,G/301,302,303					
303 Misc. Intangible Plant	.00	.00	.00	.00	.00
I Intangible (E,G/301,302,303	.00	.00	.00	.00	.00
0 Common Utility	9,428.46-	4,905,677.15-	16,640.65	4,671,215.39	227,249.57-
1 Electric					
D Dist (E/360-373,G/374-387)					
3601 Land	.00	.00	.00	.00	.00
362 Station Equipment	.00	.00	1,364.02	1,172.25-	191.77
364 Poles, Towers & Fixtures	3,835.79	.00	3,153.87	6,260.45-	729.21
365 Overhead Conductors & Dev	3,402.73	.00	.00	3,402.73-	.00
367 Under. Conductors & Devic	11,032.04	17,797.82-	94,441.55	55,926.98-	31,748.79
369 Services	3,561.33	2,665.99-	20,764.36	17,452.46-	4,207.24
371 Install. on Cust. Premise	186.19	3,678.45-	4,397.35	272.24-	632.85
373 Street Light. & Signal Sy	1,079.22	3,986.85-	16,972.02	6,419.26-	7,645.13
D Dist (E/360-373,G/374-387)	23,097.30	28,129.11-	141,093.17	90,906.37-	45,154.99
G General (E,G/389-398)					
390 Structures & Improvements	220,646.00-	.00	.00	.00	220,646.00-
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3914 Prime/Sun Computers	.00	.00	.00	.00	.00
3915 Other Computer Equipment	.00	.00	.00	.00	.00
3922 Vehicles	3,001.87-	52,485.39-	1.87	55,485.39	.00
393 Stores Equipment	.00	.00	.00	.00	.00
3941 Misc. Tools - Nonunitized	2,960.00-	2,500.00-	287.00	5,173.00	.00
3962 Power Operated Equipment	35,000.00-	800.00-	.00	35,500.00	300.00-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3975 Supervisory & Telemeterin	.00	.00	.00	.00	.00
3976 Scada System	.00	.00	.00	.00	.00
G General (E,G/389-398)	261,607.87-	55,785.39-	288.87	96,158.39	220,946.00-

MDU Resources Group Inc.
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Project No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
00001 Montana Dakota Utilities Co.					
ND North Dakota					
1 Electric					
O Other Production (E/340-346					
341806 Structures & Improvements	2,487.25-	.00	.00	.00	2,487.25-
O Other Production (E/340-346	2,487.25-	.00	.00	.00	2,487.25-
S Steam Production (E/310-316					
310804 Land and Land Rights-Beul	1,825,996.47-	.00	1,803.11	996.11-	1,825,189.47-
311807 Structures & Improvements	138,503.00-	.00	.00	.00	138,503.00-
311810 Structures & Improvements	.00	.00	2,463.17	2,463.17-	.00
311830 Structures & Improvements	.00	.00	545.99	.00	545.99
312805 Boiler Plant Equipment	1,336.76-	.00	1,925.41	2,219.00-	1,630.35-
312810 Boiler Plant Equipment	2,849.89	4,000.00-	15,655.27	4,603.30-	9,901.86
312830 Boiler Plant Equipment	2,846.13	3,274.75-	6,729.23	5,124.63-	1,175.98
314810 Turbogenerator Units	930,300.00-	291,456.07-	60,000.00	1,161,756.07	.00
314830 Turbogenerator Units	.00	.00	.00	.00	.00
316810 Misc. Power Plant Equipme	331.03	4,347.00-	1,521.29	13.60-	2,508.28-
316830 Misc. Power Plant Equipme	518.43-	5,345.28-	945.61	4,015.60	902.50-
S Steam Production (E/310-316	2,890,627.61-	308,423.10-	91,589.08	1,150,351.86	1,957,109.77-
T Elec Transmission (350-358)					
353 Station Equipment	401,873.26-	517,758.63-	5,833.72	911,043.13	2,755.04-
355 Poles & Fixtures	.00	11,458.45-	81,258.68	54,294.54	124,094.77
356 Overhead Conductor & Devi	353.56	2,955.68-	8,792.22	6,341.94-	151.84-
T Elec Transmission (350-358)	401,519.70-	532,172.76-	95,884.62	958,995.73	121,187.89
1 Electric	3,533,145.13-	924,510.36-	328,855.74	2,114,599.61	2,014,200.14-
2 Natural Gas					
D Dist (E/360-373,G/374-387)					
3741 Land	.00	.00	.00	.00	.00
376 Mains	12,135.99	458.92	83,055.34	79,753.42-	15,896.83
378 Meas. & Reg. Equip. - Gen	196.84	.00	2,214.67	2,353.57-	57.94
379 Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
381 Positive Meters	146.75	.00	.00	146.75-	.00
3871 Cathodic Protection Equip	.00	.00	29.49	.00	29.49
D Dist (E/360-373,G/374-387)	12,479.58	458.92	85,299.50	82,253.74-	15,984.26
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	2,030.00	.00	2,030.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	2,826.00-	39,334.00-	.00	33,703.00	8,457.00-
3942 Misc. Tools - Unitized	.00	.00	.00	.00	.00
3944 Vehicle Refueling Equipme	.00	.00	.00	.00	.00

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 2001

Project No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
00001 Montana Dakota Utilities Co.					
ND North Dakota					
2 Natural Gas					
G General (E,G/389-398)					
395 Laboratory Equipment	500.00-	.00	.00	500.00	.00
3961 Work Equipment Trailers	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	489,588.46-	368.13	489,220.33	.00
3971 Fixed Radio Comm. Equipme	.00	.00	62.76	.00	62.76
G General (E,G/389-398)	3,326.00-	528,922.46-	2,460.89	523,423.33	6,364.24-
2 Natural Gas	9,153.58	528,463.54-	87,760.39	441,169.59	9,620.02
4 Non-utility					
G General (E,G/389-398)					
3890 Land and Land Rights	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	.00	.00	.00	.00
4 Non-utility	.00	.00	.00	.00	.00
ND North Dakota	3,533,420.01-	6,358,651.05-	433,256.78	7,226,984.59	2,231,829.69-
SD South Dakota					
0 Common Utility					
G General (E,G/389-398)					
390 Structures & Improvements	.00	.00	.00	.00	.00
3911 Office Furniture & Equipm	.00	.00	.00	.00	.00
3922 Vehicles	.00	13,100.00-	.00	13,100.00	.00
3972 Mobile Radio Comm. Equipm	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	13,100.00-	.00	13,100.00	.00
0 Common Utility	.00	13,100.00-	.00	13,100.00	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
3602 Rights of Way	.00	36.39-	128.22	91.83-	.00
362 Station Equipment	.00	.00	.00	.00	.00
364 Poles, Towers & Fixtures	.00	.00	.00	.00	.00
365 Overhead Conductors & Dev	.00	.00	.00	.00	.00
367 Under. Conductors & Devic	4,424.01	3,186.79-	13,239.65	11,885.08-	2,591.79
369 Services	1,373.46	958.05-	6,753.06	6,084.15-	1,084.32
371 Install. on Cust. Premise	107.33	1,061.98-	1,087.05	502.55-	370.15-
373 Street Light. & Signal Sy	195.56	1,135.71-	9,323.33	2,241.71-	6,141.47
D Dist (E/360-373,G/374-387)	6,100.36	6,378.92-	30,531.31	20,805.32-	9,447.43

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 2001

Project	No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
G	General (E,G/389-398)					
3890	Land and Land Rights	.00	.00	.00	.00	.00
390	Structures & Improvements	.00	.00	.00	.00	.00
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3922	Vehicles	4,500.00-	.00	.00	4,500.00	.00
3941	Misc. Tools - Nonunitized	.00	3,500.00-	.00	3,500.00	.00
3962	Power Operated Equipment	.00	.00	.00	.00	.00
3976	Scada System	.00	.00	.00	.00	.00
G	General (E,G/389-398)	4,500.00-	3,500.00-	.00	8,000.00	.00
S	Steam Production (E/310-316					
311814	Structures & Improvements	6,366.00-	.00	.00	.00	6,366.00-
311861	Structures & Improvements	.00	29.51-	66.73	29.51	66.73
312861	Boiler Plant Equipment	199.00	.00	.00	199.00-	.00
314861	Turbogenerator Units	.00	.00	.00	.00	.00
316861	Misc. Power Plant Equipme	295.10-	3,373.79-	.00	2,462.95	1,205.94-
S	Steam Production (E/310-316	6,462.10-	3,403.30-	66.73	2,293.46	7,505.21-
T	Elec Transmission (350-358)					
3502	Rights of Way	1,042.17	.00	.00	1,042.17-	.00
353	Station Equipment	.00	3,526.34-	3,013.19	.00	513.15-
355	Poles & Fixtures	5,100.55	1,127.50-	3,973.05-	1,034.25-	1,034.25-
356	Overhead Conductor & Devi	782.68	167.36-	4,684.20	4,586.22-	713.30
T	Elec Transmission (350-358)	6,925.40	4,821.20-	3,724.34	6,662.64-	834.10-
1	Electric	2,063.66	18,103.42-	34,322.38	17,174.50-	1,108.12
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
3741	Land	.00	.00	.00	.00	.00
375	Structures & Improvements	.00	.00	.00	.00	.00
376	Mains	5,644.91	.00	45,781.24	38,281.92-	13,144.23
378	Meas. & Reg. Equip. - Gen	258.66-	544.97-	268.58	803.63	268.58
379	Meas. & Reg. Equip.-City	.00	.00	.00	.00	.00
385	Ind. meas. & Reg. Station	.00	.00	.00	.00	.00
3863	CNG Demonstration	.00	.00	.00	.00	.00
3871	Cathodic Protection Equip	.00	.00	.00	.00	.00
D	Dist (E/360-373,G/374-387)	5,386.25	544.97-	46,049.82	37,478.29-	13,412.81
G	General (E,G/389-398)					
390	Structures & Improvements	.00	293.68-	21,500.00	.00	21,206.32
3911	Office Furniture & Equipm	.00	1,015.00	.00	.00	1,015.00
3921	Trailers	.00	1,076.00-	.00	1,076.00	.00
3922	Vehicles	.00	31,538.75-	1,651.14	16,779.60	13,108.01-

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 2001

Project No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
00001 Montana Dakota Utilities Co.					
SD South Dakota					
2 Natural Gas					
G General (E,G/389-398)					
3941 Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3943 Vehicle Maintenance Equip	.00	.00	.00	.00	.00
3961 Work Equipment Trailers	.00	.00	.00	.00	.00
3962 Power Operated Equipment	.00	323,556.37-	346.77	158,123.17	165,086.43-
3971 Fixed Radio Comm. Equipme	.00	.00	.00	.00	.00
3973 General Telephone Comm. E	.00	.00	.00	.00	.00
G General (E,G/389-398)	.00	355,449.80-	23,497.91	175,978.77	155,973.12-
2 Natural Gas	5,386.25	355,994.77-	69,547.73	138,500.48	142,560.31-
4 Non-utility					
D Dist (E/360-373,G/374-387)					
3871 Cathodic Protection Equip	.00	.00	.00	.00	.00
D Dist (E/360-373,G/374-387)	.00	.00	.00	.00	.00
4 Non-utility	.00	.00	.00	.00	.00
SD South Dakota	7,449.91	387,198.19-	103,870.11	134,425.98	141,452.19-
WY Wyoming					
0 Common Utility					
G General (E,G/389-398)					
3911 Office Furniture & Equipm	.00	230.00-	.00	230.00	.00
3922 Vehicles	1,200.00-	.00	.00	1,200.00	.00
G General (E,G/389-398)	1,200.00-	230.00-	.00	1,430.00	.00
0 Common Utility	1,200.00-	230.00-	.00	1,430.00	.00
1 Electric					
D Dist (E/360-373,G/374-387)					
362 Station Equipment	.00	6,842.59-	9,287.53	6,017.53-	3,572.59-
364 Poles, Towers & Fixtures	457.36	2,050.80-	65,078.32	32,982.12-	30,502.76
365 Overhead Conductors & Dev	.00	.00	17,320.34	.00	17,320.34
367 Under. Conductors & Devic	12,641.62	899.05-	27,830.80	20,768.36-	18,805.01
369 Services	1,515.48	220.22-	4,028.22	3,679.97-	1,643.51
370 Meters	.00	.00	.00	.00	.00
371 Install. on Cust. Premise	987.86	1,383.65-	1,682.92	1,118.10-	169.03
373 Street Light. & Signal Sy	2,756.66	39.53-	1,058.95	3,553.42-	222.66
D Dist (E/360-373,G/374-387)	18,358.98	11,435.84-	126,287.08	68,119.50-	65,090.72

MDU Resources Group Inc.
Cumulative RWIP Additions & Closeouts
By Co., Utility, Division, & Function
As of December 31, 2001

Project	No. and Description	RWIP Beginning Balance 1/1/01	RWIP Salvage/ Other	RWIP Removal Costs	RWIP Closeouts	RWIP Ending Balance 12/31/01
G	General (E,G/389-398)					
3922	Vehicles	.00	5,500.00-	.00	5,500.00	.00
3962	Power Operated Equipment	16,000.00-	.00	.00	16,000.00	.00
3976	Scada System	.00	.00	.00	.00	.00
G	General (E,G/389-398)	16,000.00-	5,500.00-	.00	21,500.00	.00
T	Elec Transmission (350-358)					
353	Station Equipment	.00	.00	.00	.00	.00
356	Overhead Conductor & Devi	.00	.00	6,102.57	5,102.57-	1,000.00
T	Elec Transmission (350-358)	.00	.00	6,102.57	5,102.57-	1,000.00
1	Electric	2,358.98	16,935.84-	132,389.65	51,722.07-	66,090.72
2	Natural Gas					
D	Dist (E/360-373,G/374-387)					
3741	Land	.00	.00	.00	.00	.00
376	Mains	8,519.78	.00	48,018.03	44,802.24-	11,735.57
378	Meas. & Reg. Equip. - Gen	.00	.00	.00	.00	.00
D	Dist (E/360-373,G/374-387)	8,519.78	.00	48,018.03	44,802.24-	11,735.57
G	General (E,G/389-398)					
390	Structures & Improvements	.00	.00	.00	.00	.00
3911	Office Furniture & Equipm	.00	.00	.00	.00	.00
3921	Trailers	.00	.00	.00	.00	.00
3922	Vehicles	.00	12,944.00-	.00	12,944.00	.00
3941	Misc. Tools - Nonunitized	.00	.00	.00	.00	.00
3944	Vehicle Refueling Equipme	.00	.00	.00	.00	.00
3962	Power Operated Equipment	.00	110,100.00-	217.50	98,382.50	11,500.00-
G	General (E,G/389-398)	.00	123,044.00-	217.50	111,326.50	11,500.00-
2	Natural Gas	8,519.78	123,044.00-	48,235.53	66,524.26	235.57
WY	Wyoming	9,678.76	140,209.84-	180,625.18	16,232.19	66,326.29
00001	Montana Dakota Utilities Co.	4,363,616.56-	7,491,838.31-	1,087,182.40	7,561,318.18	3,206,954.29-

Direct Testimony of

Michael J. Majoros, Jr.

Page 6 Table

Expanded

Comparison of Annual Depreciation Cash InFlows To Construction Outflows - MDU 1996 – 2001

Year	Depreciation	Utility Construction/ Acquistion	Cash Flow Incremental	Utility & Common Plant Construction	Incremental Cash Flow
(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6) = (2)-(5)
1996	$23,932	$21,796	$2,136	$24,464	($532)
1997	24,505	24,545	(40)	28,365	(3,860)
1998	25,279	17,564	7,715	21,983	3,296
1999	25,725	21,102	4,623	27,423	(1,698)
2000	27,514	17,263	10,251	24,382	3,132
2002	28,824	25,036	3,788	28,753	71
Total	$155,779	$127,306	$28,473	$155,370	$409

Direct testimony of Majoros - Page 6
Table expanded
by Public Service Commission
Exhibit # 20
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

PENGAD 800-631-6989 EXHIBIT 20

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
COMPARISON OF COMPANY AVERAGE SERVICE LIVES WITH AGA/EEI STATISTICS

Acct. No.	Account	Balance @ 12/31/01	Company ASL	AGA/EEI Statistics - Gas Plant					
				Mean	Weighted Average	Median	Mode	Minimum	Maximum
	Distribution Plant								
374.1	Land	$41,687							
374.2	Rights of Way	44,836							
375	Structures & Improvements	180,117	39	43.4	39.6	42.0	40.0	7.1	66.0
376	Mains	27,079,883	36	54.6	54.2	54.0	50.0	10.0	80.0
378	Meas. & Reg. Equip.-General	520,093	33	33.8	36.1	34.0	30.0	11.1	55.0
379	Meas. & Reg. Equip.-City Gate	174,002	30	32.0	31.8	35.0	35.0	20.0	53.2
380	Services	12,124,678	34	39.6	39.8	40.0	40.0	10.2	63.0
381	Positive Meters	11,983,141	33	32.3	33.9	34.0	35.0	5.0	60.0
383	Service Regulators	1,677,415	34	33.3	31.9	31.0	30.0	12.3	60.0
385	Ind. Meas. & Reg. Station Eqpt.	371,028	35	30.3	30.2	30.0	22.0	8.8	50.0
386.1	Misc. Property on Cust. Premise	1,680		18.3	7.1	14.0	7.0	3.5	52.0
386.2	Other Property on Cust. Premise	113,207		18.3	7.1	14.0	7.0	3.5	52.0
387.1	Cathodic Protection Equip.	443,741		18.6	17.5	15.0	10.0	5.0	39.4
387.2	Other Distribution Equip.	331,598	20	18.6	17.5	15.0	10.0	5.0	39.4
	Total Distribution Plant	$55,087,106							

Source:
Company ASLs - Statement I
Statistics - AGA/EEI "A Survey of Depreciation Statistics", 1998-1999.

MONTANA-DAKOTA UTILITIES
GAS UTILITY - NORTH DAKOTA
COMPARISON OF DISTRIBUTION, GENERAL AND COMMON
ADDITIONS AND DEPRECIATION EXPENSE
1986 - 2001

Year (1)	Depreciation Expense (2)	Additions (3)	Incremental Cash Flow (4) = (2) - (3)
1986	$ 1,945,514	$ 970,041	$ 975,473
1987	2,045,034	763,811	1,281,223
1988	2,018,580	1,054,487	964,093
1989	1,968,799	1,013,769	955,030
1990	1,939,600	1,193,070	746,530
1991	1,976,220	1,464,758	511,462
1992	2,017,405	1,652,392	365,013
1993	2,079,386	1,927,077	152,309
1994	2,362,365	2,311,487	50,878
1995	2,489,615	1,873,149	616,466
1996	2,541,678	2,743,247	(201,569)
1997	2,624,125	2,975,295	(351,170)
1998	2,676,508	2,205,886	470,622
1999	2,727,855	2,080,264	647,591
2000	2,809,741	2,287,542	522,199
2001	2,870,394	2,367,123	503,271
Total	$ 37,092,819	$ 28,883,399	$ 8,209,420

Sources:

Depreciation Expense - Company response to Data Request No. 29

1986 - 1999 Additions - Company response to Data Request No. 10.

2000 - 2001 Additions calculated using BOY and EOY balances from response to Data Request No. 8, p. 29 and retirements from response to Data Request No. 2, p. 20.

Montana-Dakota Utilities Co. - North Dakota

Geometric Mean Turnover Analysis

Account 376 - Mains

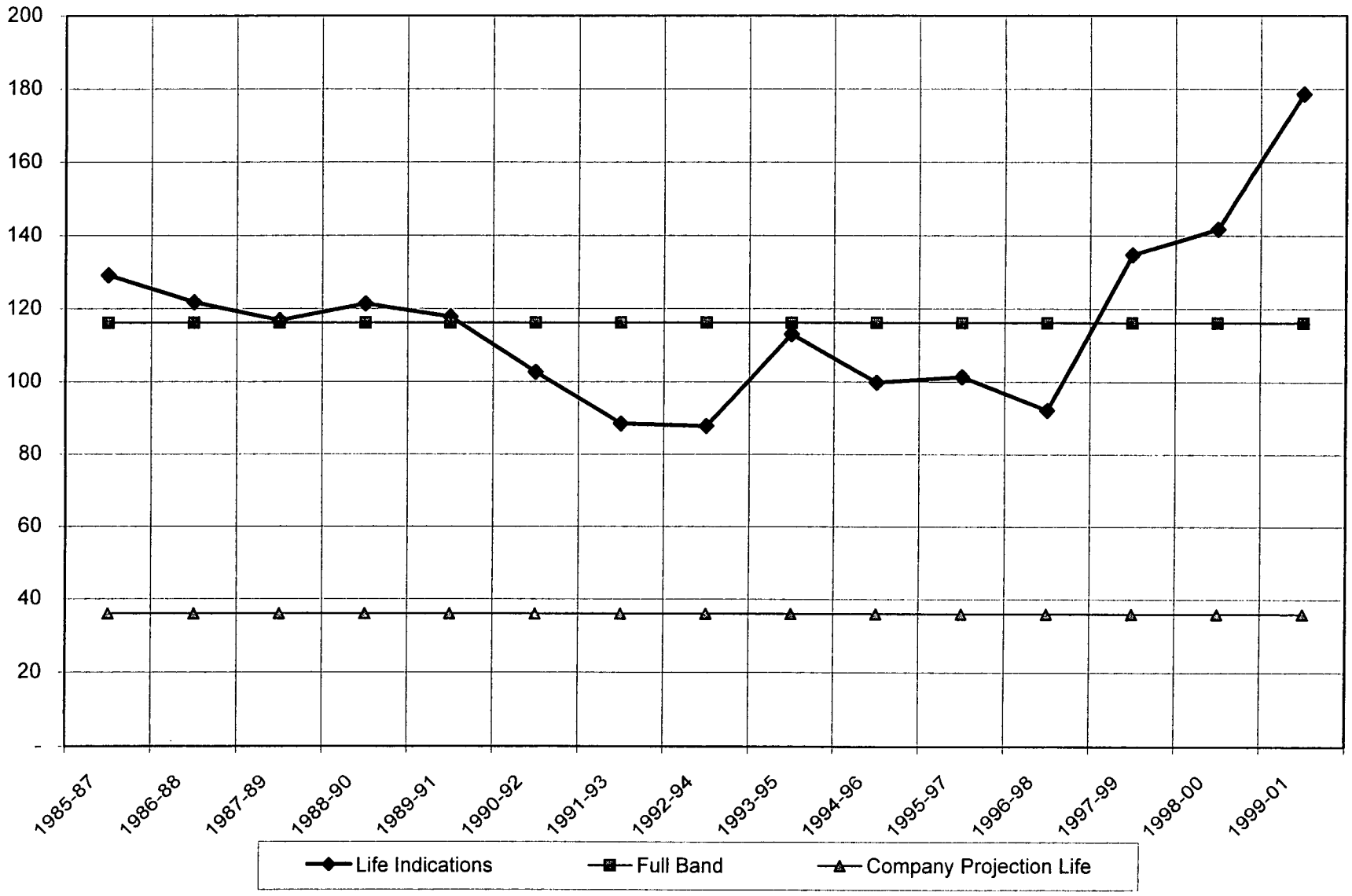
Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	Avg. Plant Balance	Additions	Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate
	a	b=(a+(a+1))/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1985	18,780,327	18,996,269	474,801	42,916	0.02499	0.00226	133.08							
1986	19,212,212	19,385,289	394,155	48,000	0.02033	0.00248	140.93							
1987	19,558,366	19,648,436	266,848	86,709	0.01358	0.00441	129.17	1985-87	58,029,995	1,135,804	177,624	0.01957	0.00306	129.20
1988	19,738,506	19,960,667	510,037	65,716	0.02555	0.00329	109.03	1986-88	58,994,392	1,171,040	200,425	0.01985	0.00340	121.77
1989	20,182,828	20,330,977	372,697	76,399	0.01833	0.00376	120.49	1987-89	59,940,080	1,149,583	228,823	0.01918	0.00382	116
1990	20,479,126	20,677,246	444,200	47,959	0.02148	0.00232	141.67	1988-90	60,968,890	1,326,934	190,073	0.02176	0.00312	121.
1991	20,875,367	21,063,026	467,206	91,888	0.02218	0.00436	101.66	1989-91	62,071,249	1,284,103	216,246	0.02069	0.00348	117.79
1992	21,250,685	21,625,986	829,382	78,780	0.03835	0.00364	84.60	1990-92	63,366,258	1,740,788	218,626	0.02747	0.00345	102.71
1993	22,001,287	22,397,951	872,174	78,846	0.03894	0.00352	85.41	1991-93	65,086,963	2,168,762	249,514	0.03332	0.00383	88.48
1994	22,794,615	23,132,831	756,750	80,319	0.03271	0.00347	93.83	1992-94	67,156,768	2,458,306	237,945	0.03661	0.00354	87.81
1995	23,471,047	23,763,503	594,555	9,642	0.02502	0.00041	313.86	1993-95	69,294,285	2,223,479	168,807	0.03209	0.00244	113.11
1996	24,055,960	24,544,408	1,096,116	119,219	0.04466	0.00486	67.90	1994-96	71,440,742	2,447,421	209,179	0.03426	0.00293	99.85
1997	25,032,857	25,337,012	700,195	91,885	0.02764	0.00363	99.89	1995-97	73,644,923	2,390,866	220,746	0.03246	0.00300	101.37
1998	25,641,167	25,824,579	455,309	88,485	0.01763	0.00343	128.66	1996-98	75,705,999	2,251,620	299,588	0.02974	0.00396	92.18
1999	26,007,991	26,131,401	293,318	46,498	0.01122	0.00178	223.76	1997-99	77,292,992	1,448,822	226,868	0.01874	0.00294	134.82
2000	26,254,811	26,534,442	644,328	85,066	0.02428	0.00321	113.34	1998-00	78,490,422	1,392,954	220,048	0.01775	0.00280	141.77
2001	26,814,073	26,946,978	295,335	29,525	0.01096	0.00110	288.57	1999-01	79,612,821	1,232,981	161,089	0.01549	0.00202	178.64
1985 - 2001	382,151,224	386,301,002	9,467,406	1,167,850	0.02451	0.00302	116.18							

Sources: Company responses to Data Requests Nos. 2 and 10.

Note: Revised on 9/11/02 to reflect 3-year bands and correct average plant balance.

Company: Montana-Dakota Utilities Co. - ND
Account: 376
Category: Mains

Geometric Mean Rolling Band Analysis
Life Indications - Account 376 - Mains



Montana-Dakota Utilities Co. - North Dakota

Geometric Mean Turnover Analysis

Account 380 - Services

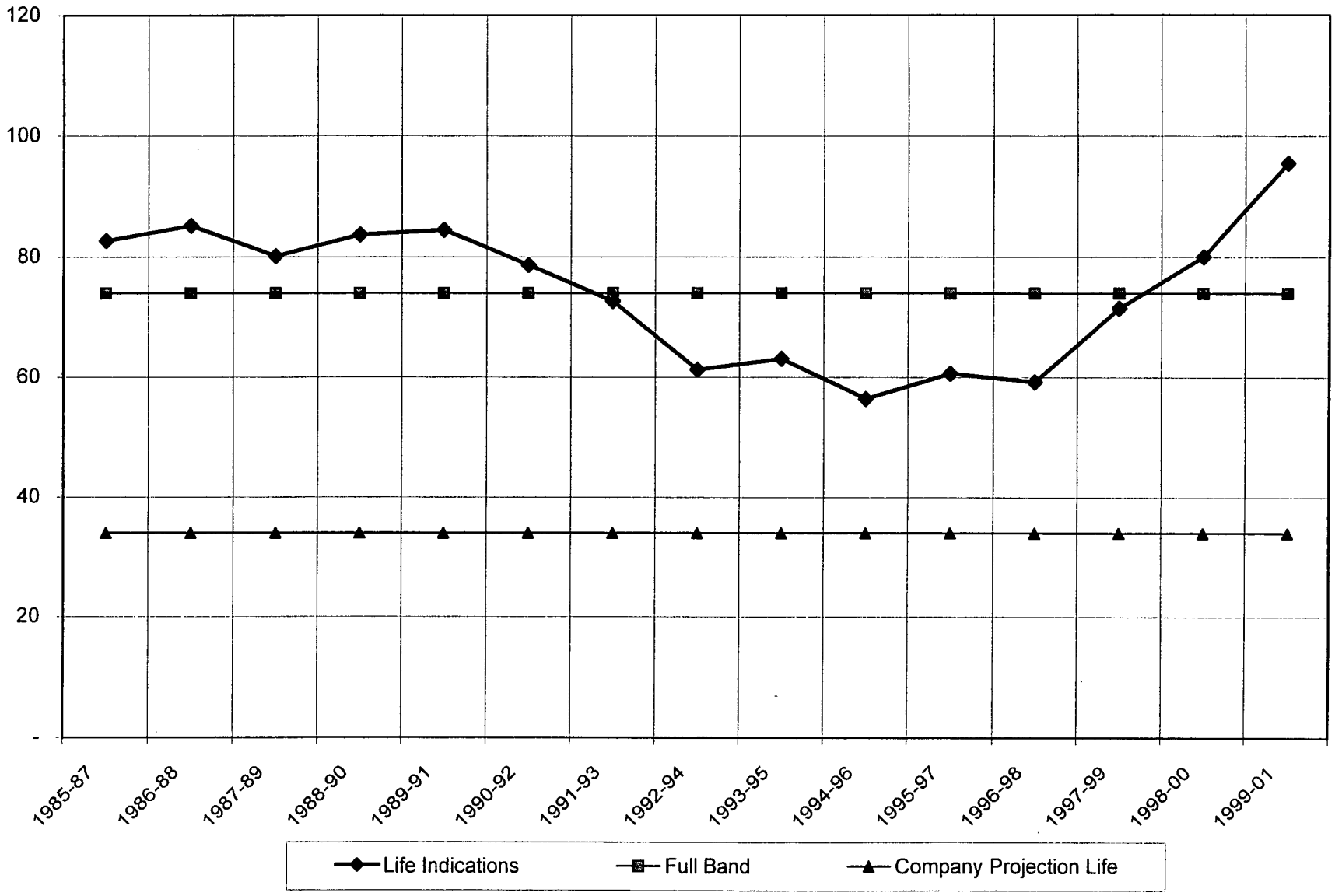
									3 Year Band					
Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	Avg. Plant Balance	Additions	Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate
	a	b=(a+(a+1))/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1985	7,393,465	7,535,249	316,440	32,872	0.04199	0.00436	73.88							
1986	7,677,033	7,788,294	245,045	22,522	0.03146	0.00289	104.84							
1987	7,899,556	8,002,352	248,375	42,782	0.03104	0.00535	77.63	1985-87	23,325,895	809,860	98,176	0.03472	0.00421	82.72
1988	8,105,149	8,213,750	257,548	40,346	0.03136	0.00491	80.58	1986-88	24,004,396	750,968	105,650	0.03128	0.00440	85.22
1989	8,322,351	8,423,666	245,279	42,650	0.02912	0.00506	82.36	1987-89	24,639,768	751,203	125,777	0.03049	0.00510	80.1[illegible]
1990	8,524,981	8,623,935	237,720	39,812	0.02757	0.00462	88.65	1988-90	25,261,351	740,548	122,807	0.02932	0.00486	8[illegible]
1991	8,722,889	8,826,672	252,518	44,953	0.02861	0.00509	82.85	1989-91	25,874,274	735,518	127,414	0.02843	0.00492	84.[illegible]
1992	8,930,455	9,038,081	277,931	62,678	0.03075	0.00693	68.48	1990-92	26,488,689	768,169	147,443	0.02900	0.00557	78.71
1993	9,145,708	9,267,222	302,772	59,744	0.03267	0.00645	68.90	1991-93	27,131,975	833,221	167,375	0.03071	0.00617	72.65
1994	9,388,736	9,578,162	456,259	77,407	0.04764	0.00808	50.97	1992-94	27,883,465	1,036,961	199,829	0.03719	0.00717	61.25
1995	9,767,587	9,949,156	404,949	41,810	0.04070	0.00420	76.46	1993-95	28,794,540	1,163,979	178,961	0.04042	0.00622	63.09
1996	10,130,726	10,316,934	464,213	91,796	0.04500	0.00890	49.98	1994-96	29,844,252	1,325,420	211,013	0.04441	0.00707	56.43
1997	10,503,142	10,700,286	457,193	62,906	0.04273	0.00588	63.10	1995-97	30,966,376	1,326,354	196,512	0.04283	0.00635	60.65
1998	10,897,429	11,061,416	395,971	67,997	0.03580	0.00615	67.41	1996-98	32,078,635	1,317,376	222,699	0.04107	0.00694	59.22
1999	11,225,403	11,354,340	311,083	53,208	0.02740	0.00469	88.25	1997-99	33,116,042	1,164,246	184,111	0.03516	0.00556	71.53
2000	11,483,278	11,664,000	403,227	41,783	0.03457	0.00358	89.86	1998-00	34,079,756	1,110,281	162,988	0.03258	0.00478	80.11
2001	11,844,722	11,984,700	315,390	35,434	0.02632	0.00296	113.37	1999-01	35,003,040	1,029,700	130,425	0.02942	0.00373	95.51
1985 - 2001	159,962,609	162,328,215	5,591,912	860,699	0.03445	0.00530	73.99							

Sources: Company responses to Data Requests Nos. 2 and 10.

Note: Revised on 9/11/02 to reflect 3-year bands and correct average plant balance.

Company: Montana-Dakota Utilities Co. - ND
Account: 380
Category: Services

Geometric Mean Rolling Band Analysis
Life Indications - Account 380 - Services



Ex 18

CONOCO NYSE-COC

RECENT PRICE 25.88 | P/E RATIO 15.2 (Trailing: 13.0 Median: NMF) | P/E RATIO .83 | DIV'D YLD 2.9% | VALUE LINE 411

TIMELINESS — D
SAFETY 3 New 3/26/99
TECHNICAL — D
BETA .85 (1.00 = Market)

2005-07 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+115%)	22%
Low	35	(+35%)	10%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	5	1	1	0	0	1
to Sell	0	0	0	0	0	1	0	0	1

Institutional Decisions

	3Q2001	4Q2001	1Q2002
to Buy	254	293	281
to Sell	218	219	227
Hld's(000)	512533	503304	512500

LEGENDS
---- Relative Price Strength
Options: Yes
Shaded area indicates recession

Percent shares traded: 15.0, 10.0, 5.0

High: 25.8 31.3 29.6 33.0 29.8
Low: 19.4 19.3 18.8 23.7 25.5

Target Price Range 2005 | 2006 | 2007

% TOT. RETURN 5/02

	THIS STOCK	VL ARITH. INDEX
1 yr.	—	-0.2
3 yr.	—	22.2
5 yr.	—	62.4

Conoco became a publicly traded company in October 1998 after DuPont conducted an initial public offering (IPO) for 30% of its oil subsidiary. DuPont issued 191.5 million shares to the public at $23 a share, for a total of about $4.4 billion. In August, 1999, DuPont conducted a tax-free spinoff of the remaining 70% of Conoco stock to DuPont shareholders, giving the entire divestiture a transaction value of about $21 billion.

CAPITAL STRUCTURE as of 3/31/02
Total Debt $9454 mill. Due in 5 Yrs $4435 mill.
LT Debt $8179 mill. LT Interest $550 mill.
(Total interest coverage: 10.0x) (56% of Cap'l).
Uncapitalized Leases: $329 mill.
Pension Liability $530 mill. in '00.
Pfd Stock None
Common Stock 626,682,434 shs. (44% of Cap'l)
As of 5/3/02
(Options exercisable: 5%)
MARKET CAP: $18.0 billion (Large Cap)

CURRENT POSITION ($MILL.)	2000	2001	3/31/02
Cash Assets	342	388	221
Receivables	1837	1894	2045
Inventory (LIFO)	791	995	1087
Other	441	1066	951
Current Assets	3411	4343	4304
Accts Payable	1723	1950	1877
Debt Due	258	1125	1275
Other	2208	2427	2680
Current Liab.	4187	5502	5832

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Revenues	--	--	3.0%
"Cash Flow"	--	--	3.0%
Earnings	--	--	2.5%
Dividends	--	--	1.0%
Book Value	--	--	14.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	5311	6252	7409	8067	27039
2000	8524	9357	10587	10269	38737
2001	10625	10377	9627	8108	38737
2002	7998	*8500*	*8700*	*8802*	*34000*
2003	*8850*	*8900*	*9000*	*9050*	*35800*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	.13	.18	.41	.51	1.23
2000	.63	.72	.79	.86	3.00
2001	.97	.95	.64	.31	2.87
2002	.09	*.50*	*.55*	*.56*	*1.70*
2003	*.45*	*.55*	*.55*	*.60*	*2.15*

Calendar	GROSS QUARTERLY DIV'DS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	--	---	--	--	--
1999	.19	.19	.19	.19	.76
2000	.19	.19	.19	.19	.76
2001	.19	.19	.19	.19	.76
2002	.19	.19			

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
	--	--	--	--	--	--	36.31	43.22	61.66	61.98	*54.20*	*57.10*	Revenues per sh	*66.65*
	--	--	--	--	--	--	2.49	3.16	5.10	5.45	*4.10*	*4.60*	"Cash Flow" per sh	*5.45*
	--	--	--	--	--	--	.71	1.23	3.00	2.87	*1.70*	*2.15*	Earnings per sh A	*2.75*
	--	--	--	--	--	--	.71	.76	.76	.76	*.78*	*.78*	Div'ds Decl'd per sh B	*.80*
	--	--	--	--	--	--	3.13	2.68	3.06	4.32	*2.50*	*2.60*	Cap'l Spending per sh	*2.75*
	--	--	--	--	--	--	7.07	7.28	8.96	10.58	*11.55*	*12.95*	Book Value per sh	*18.25*
	--	--	--	--	--	--	627.79	625.58	628.28	625.00	*627.00*	*627.00*	Common Shs Outst'g C	*627.00*
	--	--	--	--	--	--	32.8	20.7	8.1	9.9	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
	--	--	--	--	--	--	1.71	1.18	.53	.51	*Value Line*		Relative P/E Ratio	*1.05*
	--	--	--	--	--	--	--	2.8%	3.1%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*1.8%*
	--	--	--	--	--	25796	22796	27039	38737	38737	*34000*	*35800*	Revenues ($mill)	*41800*
	--	--	--	--	--	32.5%	34.4%	33.9%	29.8%	29.4%	*27.0%*	*28.5%*	Operating Margin	*32.5%*
	--	--	--	--	--	1179	1113	1193	1301	1578	*1500*	*1550*	Depreciation ($mill)	*1700*
	--	--	--	--	--	1097	450	782	1902	1831	*1065*	*1345*	Net Profit ($mill)	*1720*
	--	--	--	--	--	47.9%	35.2%	37.7%	45.0%	43.2%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
	--	--	--	--	--	4.3%	2.0%	2.9%	4.9%	4.7%	*3.1%*	*3.8%*	Net Profit Margin	*4.1%*
	--	--	--	--	--	567	45.0	d690	d776	d1159	*d1700*	*d1425*	Working Cap'l ($mill)	*d925*
	--	--	--	--	--	1558	4689	4080	4138	8267	*8200*	*8050*	Long-Term Debt ($mill)	*6750*
	--	--	--	--	--	7898	4438	4555	5628	6610	*7250*	*8125*	Shr. Equity ($mill)	*11450*
	--	--	--	--	--	11.8%	5.7%	10.6%	20.9%	13.6%	*8.5%*	*10.0%*	Return on Total Cap'l	*10.5%*
	--	--	--	--	--	13.9%	10.1%	17.2%	33.8%	27.7%	*14.5%*	*16.5%*	Return on Shr. Equity	*15.0%*
	--	--	--	--	--	13.9%	10.1%	7.4%	25.4%	20.5%	*8.0%*	*11.0%*	Retained to Com Eq	*10.5%*
	--	--	--	--	--	--	--	57%	25%	26%	*45%*	*35%*	All Div'ds to Net Prof	*29%*

BUSINESS: Conoco is an integrated energy company engaged in the exploration for, development, production and sale of crude oil, natural gas, the refining of crude oil and other feedstocks into petroleum items, and the distribution of petroleum products. Daily 2001 prod.: oil, 322,000 barrels; natural gas, 2.0 bill. cub. feet. Reserves at 12/31/01: 1,153 mill. bbls. oil; 6,029 bill. cu. ft. gas. Average 5-yr. finding costs per barrel: $4.67 (vs. ind. avg. $4.28). 5-yr. replacement rate 119% (vs. ind. avg 145%). Has about 20,000 employees. FMR Corporation owns 12.4% of common stock; Officers & directors own 2.4% (4/02 proxy). Chrmn., Pres. & CEO: Archie Dunham, Inc.: DE. Addr: 600 North Dairy Ashford Road, Houston, TX 77079. Tel: 281-293-1000. Internet: www.conoco.com.

Our 2002 share-net estimate for Conoco is now $1.70, a reduction of $0.10. The revision reflects the weakness in oil prices and the extremely narrow margins available in the downstream arena in the March quarter. Energy prices have since risen and refining margins have widened, but by not enough to completely offset the difficult operating environment experienced by Big Oil at the beginning of 2002. **The planned merger of equals between Conoco and Phillips Petroleum remains on track.** Under the terms of the deal, each Conoco shareholder would receive .4677 of a share of Phillips stock for each Conoco share owned. Each Phillips share would then be exchanged for one share of the new entity to be called ConocoPhillips. All told, Conoco shareholders would own 43.3% of the new company. James Mulva, Phillips CEO, would become president and CEO of the combined entity, while Archie Dunham, Conoco chairman and CEO, would become chairman. **We believe the merger is a positive for Conoco's shareholders.** Although the deal offers a very minimal premium for owners of COC stock, it seems like a fair proposal, since Conoco shareholders would hold equity in a more competitive company (see below). The merger, which is still scheduled to be completed in the second half of 2002 (FTC approval is expected to be forthcoming) and is excluded from our financial presentation until then, would be accretive to earnings and cash flow within the first year of the merger. In fact, our projections call for ConocoPhillips to generate annual pretax savings from synergies of about $750 million. **Assuming the deal goes through,** ConocoPhillips' reserves would total 8.7 million barrels of oil equivalent (BOE), with annual production of 1.7 million BOE. Its balance sheet would benefit, with a debt-to-capital ratio in the 30% to 35% range. **The merger will likely accelerate Conoco's long-term share-earnings growth,** due to the aforementioned cost-savings synergies, and higher volumes. As a result, we advise Conoco stockholders to tender their shares for Phillips stock. In the meantime, our projections call for Conoco to deliver solid 3- to 5-year total returns as a stand-alone entity.

Charles Clark *June 21, 2002*

(A) Based on primary earnings in 1998 and diluted thereafter. There are no share earnings in 1997 since Conoco was not yet a publically traded entity. Next ergs. report due late July.

(B) Next dividend meeting in late July. Goes ex in mid-Aug. Approximate dividend payment dates: 30th of March, June, September, and December.

(C) In millions

Company's Financial Strength

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PU-399-02-183 Pages: 6

Value Line information on selected companies
by Public Service Commission
Exhibit # 18
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike

PENGAD 800-631-6989

EXHIBIT 81

FRONTIER OIL CORP. NYSE-FTO

RECENT PRICE 15.70 | P/E RATIO 10.5 (Trailing: 4.2 Median: NMF) | REL P/E RATIO 0.57 | DIV'D YLD 1.3% | VALUE LINE 413

TIMELINESS 3 New 12/21/01
SAFETY 4 New 12/21/01
TECHNICAL 4 Lowered 6/21/02
BETA .90 (1.00 = Market)

2005-07 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+155%)	26%
Low	25	(+60%)	13%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	0	1	0	0	2
to Sell	0	2	0	0	0	2	0	1	2

Institutional Decisions

	3Q2001	4Q2001	1Q2002
to Buy	37	56	48
to Sell	29	23	40
Hld's(000)	16024	18029	17676

LEGENDS
7.0 x "Cash Flow" p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Percent shares traded: 18.0, 12.0, 6.0

High:	7.4	5.3	5.9	5.9	5.0	4.1	8.5	9.3	8.3	9.1	20.3	22.8	
Low:	4.3	3.1	3.5	3.9	2.6	2.6	3.1	4.0	4.6	5.1	6.4	14.7	

Target Price Range

2005	2006	2007
		80
		60
		50
		40
		32
		24
		20
		16
		12
		10
		8
		6
		4

% TOT. RETURN 5/02

	THIS STOCK	VL ARITH INDEX
1 yr.	21.2	-0.2
3 yr.	211.2	22.2
5 yr.	306.6	62.4

1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
3.06	1.73	1.81	2.01	2.46	5.68	17.08	13.55	12.95	13.28	14.79	13.42	10.78	18.44	78.98	73.14	57.70	69.25	Sales per sh	84.60
1.13	.82	.83	.89	1.04	.57	1.02	.95	1.13	.08	.38	.61	1.06	d.15	2.27	5.14	2.55	3.00	"Cash Flow" per sh	4.25
.18	.32	.18	.19	.13	d.51	d.04	.10	.15	d.70	d.25	.28	.65	d.62	1.34	4.00	1.50	2.00	Earnings per sh A	2.65
--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	.10	.20	.20	Div'ds Decl'd per sh B	.20
.47	.73	.96	1.57	2.44	2.22	1.92	1.57	.87	.63	.49	1.32	.60	.34	.48	.88	2.10	2.20	Cap'l Spending per sh	2.75
.19	3.37	3.83	4.64	3.10	2.45	2.04	2.44	1.81	1.19	.93	1.99	2.53	1.86	3.06	6.55	7.10	7.70	Book Value per sh	10.40
12.26	19.56	19.56	19.83	19.91	22.06	22.06	27.06	27.31	27.31	27.31	28.06	27.78	27.31	26.57	25.82	26.00	26.00	Common Shs Outst'g C	26.00
30.1	20.2	35.3	41.0	NMF	--	--	45.1	32.1	--	--	17.4	11.0	--	5.3	3.2	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	12.0
2.04	1.35	2.93	3.10	NMF	--	--	2.66	2.11	--	--	1.00	.57	--	.34	.16			Relative P/E Ratio	.80
--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	.8%			Avg Ann'l Div'd Yield	.6%
						376.8	366.6	353.7	362.7	404.0	376.4	299.4	503.6	2045.2	1888.4	1500	1800	Sales ($mill)	2200
						10.5%	12.4%	14.5%	6.2%	6.9%	8.2%	12.2%	1.5%	4.6%	10.0%	4.5%	5.5%	Operating Margin	7.5%
						23.4	23.2	26.7	21.4	17.1	9.2	10.7	13.1	23.0	25.0	26.5	28.5	Depreciation ($mill)	40.0
						d1.0	2.5	4.1	d19.1	d6.9	7.8	18.8	d17.1	37.2	107.7	40.0	50.0	Net Profit ($mill)	70.0
						--	--	--	--	--	--	.6%	--	5.3%	20.7%	27.5%	30.0%	Income Tax Rate	30.0%
						NMF	.7%	1.2%	NMF	NMF	2.1%	6.3%	NMF	1.8%	5.7%	2.7%	2.8%	Net Profit Margin	3.2%
						3.4	d1.9	1.5	d2.4	d3.8	20.9	30.1	24.8	43.6	109.1	95.0	110	Working Cap'l ($mill)	140
						189.3	176.9	170.8	145.4	145.9	70.6	70.0	257.3	239.6	208.9	195	185	Long-Term Debt ($mill)	190
						45.0	66.0	49.5	32.5	25.3	55.9	70.4	50.7	81.4	169.2	185	200	Shr. Equity ($mill)	270
						3.7%	5.1%	6.6%	NMF	1.1%	11.7%	15.8%	NMF	16.5%	32.2%	12.0%	14.0%	Return on Total Cap'l	16.5%
						NMF	3.8%	8.3%	NMF	NMF	14.0%	26.8%	NMF	45.7%	63.6%	21.5%	25.0%	Return on Shr. Equity	26.0%
						NMF	3.8%	8.3%	NMF	NMF	14.0%	26.8%	NMF	45.7%	62.1%	19.0%	22.5%	Retained to Com Eq	24.0%
						--	--	--	--	--	--	--	--	--	2%	13%	10%	All Div'ds to Net Prof	7%

CAPITAL STRUCTURE as of 3/31/02
Total Debt $239.3 mill. Due in 5 Yrs $40.0 mill.
LT Debt $208.9 mill. LT Interest $10.0 mill.
(LT interest earned: 5.8x; total interest coverage: 5.8x) (55% of Cap'l)
Leases, Uncapitalized: Annual rentals $11.0 mill.
Pfd Stock None
Common Stock 26,086,831 shs. (45% of Cap'l)
as of 4/26/02
MARKET CAP: $400 million (Small Cap)

CURRENT POSITION ($MILL.)	2000	2001	3/31/02
Cash Assets	64.4	104.0	107.9
Receivables	69.2	55.8	63.9
Inventory (FIFO)	125.5	88.0	135.3
Other	13.4	13.6	25.8
Current Assets	272.5	261.4	332.9
Accts Payable	171.6	112.3	156.4
Debt Due	--	--	30.4
Other	57.3	40.0	39.0
Current Liab.	228.9	152.3	225.8

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Sales	32.5%	32.5%	7.0%
"Cash Flow"	11.0%	35.5%	10.0%
Earnings	--	--	9.0%
Dividends	--	--	37.0%
Book Value	2.0%	24.0%	18.0%

Calendar	QUARTERLY REVENUES ($ mill) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
1999	56.2	90.3	116.4	240.7	503.6
2000	449.7	526.7	536.2	532.6	2045.2
2001	431.1	553.6	538.1	365.6	1888.4
2002	336.4	410	390	363.6	1500
2003	435	475	465	425	1800

Calendar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
1999	d.18	.14	.30	d.90	d.62
2000	d.22	1.13	.36	.07	1.34
2001	.17	2.86	1.27	d.41	4.00
2002	.01	.70	.60	.19	1.50
2003	.30	.85	.70	.15	2.00

Calendar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	--	--	--	--	--
1999	--	--	--	--	--
2000	--	--	--	--	--
2001	--	--	.05	.05	.10
2002	.05	.05			

BUSINESS: Frontier Oil Corporation is an independent energy company engaged in crude oil refining and wholesale marketing of refined petroleum products. It operates refineries in Cheyenne, Wyoming and El Dorado, Kansas with a total crude oil capacity of roughly 156,000 barrels per day. The company focuses its marketing efforts in the Rocky Mountain and Plains States regions of the United States. Has about 730 employees. Ingalls & Snyder owns 12.0% of common stock; Oppenheimer Funds, 11.4%; officers and directors, 7.0% (3/02 proxy). Chairman, President, and CEO: James R. Gibbs. Incorporated: Wyoming. Address: 10000 Memorial Drive, Suite 600, Houston, Texas 77024-3411. Telephone: 713-688-9600. Internet: www.frontieroil.com.

Frontier Oil Corporation's earnings per share have dropped dramatically thus far in 2002 compared to the previous year. This can be attributed, in large part, to contracting crude oil differentials, reflecting production curtailments by OPEC. On the positive side, sales volumes and yields for the energy company have been higher, made possible by an initiative to convert chemicals production to gasoline at the El Dorado Refinery. Furthermore, refinery operating expenses have been down relative to 2001, attributable partly to decreased natural gas costs and usage. Assuming only minimal improvement in crude oil differentials, we believe that earnings per share will decrease substantially this year. Nevertheless, **the company appears to have sound 3- to 5-year prospects.** Its El Dorado and Cheyenne refineries are quality assets, as they have the ability to process heavier, less expensive types of crude oil while still producing a significant percentage of gasoline, diesel fuel, and other high-margin refined products. What's more, Frontier's operations are concentrated in the Plains States and Rocky Mountains regions, which are among the most profitable refined product markets in the U.S. Lastly, we look for the energy company to strengthen its position via purchases of additional refineries. (Future acquisitions have been excluded from our presentation, however, due to the many uncertainties involved.)

The equity's price has decreased considerably since our last report in March, stemming partly, it seems, from investors' gloomy near-term outlook on crude oil differentials. And for the coming six to 12 months, it's ranked to be just an average market performer. But these shares offer excellent price-recovery potential, as supported by our positive earnings projections. They are most appropriate for risk-tolerant accounts, though, in view of the below-average Safety rank and low Price Stability rating.

Frederick L. Harris, III *June 21, 2002*

CASH POSITION

	5-Year Av'g	3/31/02
Current Assets to Current Liabilities:	147%	147%
Cash & Equiv's to Current Liabilities:	52%	48%
Working Capital to Sales:	6%	32%

(A) Basic earnings through 1997, diluted thereafter. Excludes nonrecurring gain (losses); '86, ($1.81); '87, $1.18; '89, ($0.10); '90, ($1.07); '91, ($0.39); '94, ($0.61); '97, ($0.14); '98, ($0.10). Excludes gain from discontinued operations; '97, $0.55. Quarters may not add to total due to rounding or change in share count. Next earnings report due early Aug.
(B) Next dividend meeting mid-Sept. Next ex date late June. Dividend payment dates: the middle of January, April, July, October.
(C) In millions.

Company's Financial Strength	C++
Stock's Price Stability	35
Price Growth Persistence	50
Earnings Predictability	10

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HOLLY CORP. ASE-HOC

RECENT PRICE 15.29 | P/E RATIO 10.5 (Trailing: 4.0 Median: 12.0) | RELATIVE P/E RATIO 0.57 | DIV'D YLD 2.9% | VALUE LINE 414

TIMELINESS 4 Lowered 6/21/02
SAFETY 3 Raised 10/2/92
TECHNICAL 4 Lowered 6/14/02
BETA .85 (1.00 = Market)

2005-07 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+130%)	29%
Low	25	(+65%)	16%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	1	3	5	0	0	0	0
to Sell	0	1	1	3	5	0	0	0	0

Institutional Decisions

	3Q2001	4Q2001	1Q2002
to Buy	29	34	38
to Sell	14	17	30
Hld's(000)	10393	10726	10642

	High:	17.3	15.4	15.3	16.7	14.3	14.9	14.4	16.7	8.6	9.8	25.1	20.8
	Low:	11.1	11.3	12.7	11.9	10.6	10.8	11.6	7.0	6.1	4.6	7.1	14.3

LEGENDS
—— 5.5 x "Cash Flow" p sh
···· Relative Price Strength
2-for-1 split 7/01
Options: No
Shaded area indicates recession

Target Price Range 2005 | 2006 | 2007

% TOT. RETURN 5/02

	THIS STOCK	VL ARITH. INDEX
1 yr.	-28.4	-0.2
3 yr.	165.0	22.2
5 yr.	44.6	62.4

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
	21.20	17.13	23.38	23.11	26.59	29.64	30.69	38.20	33.46	37.25	40.97	43.70	35.72	36.23	63.98	73.78	53.55	53.55	Sales per sh A D	67.20
	1.27	.48	1.78	2.40	1.85	1.13	.78	1.89	1.91	1.71	2.34	2.01	2.47	2.80	2.60	6.51	3.75	4.00	"Cash Flow" per sh D	5.25
	.79	.12	1.38	2.01	1.45	.71	.17	1.21	1.26	.76	1.17	.80	.99	1.21	.73	4.77	1.85	2.00	Earnings per sh A B D	2.85
	.01	--	--	.16	.20	.24	.23	.15	.18	.20	.21	.26	.30	.32	.34	.37	.40	.40	Div'ds Decl'd per sh C D	.42
	.15	.20	.15	.36	.84	3.27	1.35	1.22	1.36	.92	1.11	1.84	3.01	1.63	1.28	1.85	1.40	1.45	Cap'l Spending per sh D	1.50
	1.30	1.38	2.79	.02	1.29	1.81	1.79	2.82	3.92	4.85	5.83	6.37	6.93	7.81	8.58	13.03	14.85	16.45	Book Value per sh D	21.25
	16.51	16.51	16.51	16.51	16.51	16.51	16.51	16.51	16.51	16.51	16.51	16.51	16.51	16.51	15.10	15.48	15.50	15.50	Common Shs Outst'g D	16.00
	5.2	35.0	3.6	6.5	9.4	19.0	NMF	11.1	11.4	16.6	10.2	16.4	13.8	6.3	8.9	2.3	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	10.0
	.35	2.34	.30	.49	.70	1.21	NMF	.66	.75	1.11	.64	.95	.72	.36	.58	.12			Relative P/E Ratio	.65
	.3%	--	--	1.2%	1.5%	1.8%	1.7%	1.1%	1.2%	1.6%	1.8%	2.0%	2.2%	4.2%	5.2%	3.3%			Avg Ann'l Div'd Yield	1.5%
							506.7	630.6	552.3	614.8	678.3	721.3	589.6	598.0	965.9	1142.1	830	830	Sales ($mill) A	1075
							4.6%	8.4%	10.7%	7.6%	9.1%	7.1%	10.2%	11.2%	5.8%	12.7%	8.0%	9.0%	Operating Margin	12.0%
							10.1	11.3	10.9	15.8	19.3	20.2	24.4	26.4	27.5	27.3	29.0	31.0	Depreciation ($mill)	38.0
							2.8	19.9	20.7	12.4	19.2	13.1	16.3	19.9	11.8	73.5	29.0	31.0	Net Profit ($mill)	46.0
							--	40.2%	40.8%	38.4%	39.5%	40.0%	39.1%	39.9%	37.9%	39.7%	40.0%	40.0%	Income Tax Rate	40.0%
							.5%	3.2%	3.8%	2.0%	2.8%	1.8%	2.8%	3.3%	1.2%	6.4%	3.5%	3.7%	Net Profit Margin	4.3%
							5.0	12.2	18.2	17.7	66.6	45.2	14.8	13.9	.4	57.7	50.0	55.0	Working Cap'l ($mill)	110
							80.1	74.4	68.8	54.6	86.3	75.5	70.3	56.6	42.9	34.3	25.0	20.0	Long-Term Debt ($mill)	10.0
							29.5	46.5	64.8	80.0	98.2	105.1	114.3	128.9	129.6	201.7	230	255	Shr. Equity ($mill)	340
							6.6%	20.1%	18.6%	11.7%	12.9%	9.5%	10.9%	12.4%	8.1%	32.0%	11.5%	11.5%	Return on Total Cap'l	13.0%
							9.4%	42.9%	32.0%	15.5%	20.0%	12.4%	14.3%	15.5%	9.1%	36.4%	12.5%	12.0%	Return on Shr. Equity	13.5%
							NMF	37.6%	27.5%	11.4%	16.4%	8.4%	9.9%	11.4%	4.8%	33.6%	10.5%	10.5%	Retained to Com Eq	11.5%
							NMF	12%	14%	27%	18%	32%	30%	26%	47%	8%	21%	20%	All Div'ds to Net Prof	15%

CAPITAL STRUCTURE as of 4/30/02

Total Debt $34.3 mill. Due in 5 Yrs $42.9 mill.
LT Debt $25.7 mill. LT Interest $2.5 mill.
(Total interest coverage: 5.3x) (32% of Cap'l)

Leases, Uncapitalized None

Pension Liability None

Pfd Stock None

Common Stock 15,578,128 shares (68% of Cap'l)
as of 6/4/02
MARKET CAP: $250 million (Small Cap)

CURRENT POSITION ($MILL.)

	2000	2001	4/30/02
Cash Assets	4.2	65.8	57.6
Receivables	123.5	146.1	128.8
Inventory (LIFO)	54.9	50.1	62.3
Other	12.2	22.1	30.6
Current Assets	194.8	284.1	279.3
Accts Payable	144.3	181.2	177.4
Debt Due	13.7	8.6	8.6
Other	22.9	36.6	26.8
Current Liab.	180.9	226.4	212.8

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Sales	8.0%	9.5%	2.5%
"Cash Flow"	8.5%	15.0%	5.0%
Earnings	5.0%	16.0%	4.0%
Dividends	5.5%	12.0%	3.5%
Book Value	25.0%	15.0%	14.0%

QUARTERLY SALES ($ mill.) A

Fiscal Year Ends	Oct.31	Jan.31	Apr.30	Jul.31	Full Fiscal Year
1999	143.0	120.7	143.4	190.9	598.0
2000	200.6	218.4	256.9	290.0	965.9
2001	326.0	283.1	268.2	264.8	1142.1
2002	257.9	166.8	210.3	195	830
2003	200	205	210	215	830

EARNINGS PER SHARE A B

Fiscal Year Ends	Oct.31	Jan.31	Apr.30	Jul.31	Full Fiscal Year
1999	.21	.05	.32	.63	1.21
2000	.20	d.30	.50	.33	.73
2001	1.35	.83	1.36	1.23	4.77
2002	1.27	d.03	.39	.22	1.85
2003	.55	.30	.40	.75	2.00

QUARTERLY DIVIDENDS PAID C D

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	.075	.075	.075	.08	.31
1999	.16	.08	--	.085	.33
2000	.085	.085	.085	.09	.35
2001	.18	.10	.10	.10	.48
2002	.10	.10			

BUSINESS: Holly Corporation is a refiner and marketer of petroleum products. Chief markets for 60,000 barrel-per-day Navajo refinery near Artesia, NM are in Arizona, New Mexico, and Texas. 2000 sales mix: Gasoline, 59%; Diesel fuel, 21%; Jet fuel, 11%; Asphalt, 5%; LPG and other, 4%. Also operates transportation pipelines, terminals, and a 7,000 B/D refinery at Great Falls, Montana. Invests in oil & gas exploration/production. '01 deprec. rate: 7.1%. Est'd plant age: 6 years. Has 520 employees, 1,800 shareholders. Officers & Dirs. hold 18% of stock; Brown Bros. Harriman, 20%; ESOP, 10%; 2 funds, 16% (11/01 proxy). Chrmn. and CEO: Lamar Norsworthy. Inc.: Del. Address: 100 Crescent Court, Dallas, TX 75201. Tel.: 214-871-3555. Web: www.hollycorp.com.

Earnings have declined for Holly Corporation. Over the past couple of quarters, crude oil prices have increased without a corresponding rise in finished product prices. As a result, margins have deteriorated and profits have dropped for Holly Corporation and the industry as a whole. The decline is particularly evident when compared to last year's earnings, which benefited from high prices for the refined products. Recent results were also hurt by two planned maintenance turnarounds at the Navajo Refinery.

The company continues to defend itself in the Longhorn lawsuit. Recently, the Texas district court denied Holly's motion for a summary judgment in the lawsuit brought on by Longhorn Partners Pipeline. The suit, which has been pending since August of 1998, claims that Holly supported separate litigation against Longhorn regarding a Texas pipeline. It's possible that Holly will prevail in the lawsuit. However, if Holly were to lose, we anticipate it will be unlikely the cost will be anywhere near the $1 billion Longhorn is seeking. There is a good deal riding on the decision though, since under certain conditions, the Longhorn Pipeline, once in operation, could overload the El Paso region with refined products. In the meantime, the litigation is not affecting Holly's capital expenditure budget.

We expect earnings to recover down the road. The summer driving season will likely generate better demand for the upcoming quarters. This will help margins, which already showed improvement in the latter stages of the April quarter. What's more, the ongoing operational enhancements should help the company's earnings recover. Furthermore, Holly has solid financials, which will enable it to invest in internal expansion and possibly acquisitions. All told, we expect profits to bounce back, albeit not to the levels achieved in fiscal 2001 (year ends July 31st).

Holly shares have some appeal. The company's results have been down of late due to poor industry fundamentals. The lawsuit aside, we anticipate the worst is in the past, and earnings should begin to pick up. Based on our 3- to 5-year earnings projections, this untimely stock provides above-average appreciation potential.

Evan J. Rosenthal *June 21, 2002*

(A) Fiscal year ends July 31st. (B) Diluted earnings. Excludes nonrecurring gains (losses): '87, (22¢); '93, (12¢); '95, 69¢. Excludes inventory writedown FY'99, 42¢; inventory recovery FY'99, 42¢. Next earnings report due early September. (C) Plus special distributions: 12/85, $2.23/sh.; 7/89, $10.00/sh. Next div'd meet'g about September 3rd. Goes ex about September 15th. Dividend payment dates: about Jan. 3, April 3, July 5, Oct. 6. (D) Adjusted for stock split.

Company's Financial Strength	B
Stock's Price Stability	50
Price Growth Persistence	10
Earnings Predictability	40

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TESORO PETROLEUM NYSE-TSO

RECENT PRICE 6.25 | P/E RATIO NMF (Trailing: 10.6 Median: 11.0) | RELATIVE P/E RATIO NMF | DIV'D YLD Nil | VALUE LINE 426

TIMELINESS 5 Lowered 6/14/02
SAFETY 3 Raised 6/26/98
TECHNICAL 5 Lowered 6/21/02
BETA 1.10 (1.00 = Market)

2005-07 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	11	(+75%)	15%
Low	7	(+10%)	3%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2001	4Q2001	1Q2002
to Buy	64	65	112
to Sell	42	38	40
Hld's(000)	28835	29785	50589

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996[D]	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
	104.41	95.60	80.84	54.99	71.59	77.56	67.26	58.98	35.72	39.15	38.91	35.59	46.09	92.71	165.62	125.99	105.00	110.00	Sales per sh [A]	107.00
	3.28	1.38	.59	.66	1.87	.50	d2.98	2.15	2.25	2.87	2.77	2.88	2.79	1.78	3.56	3.29	1.30	2.40	"Cash Flow" per sh	3.20
	d.27	d.80	d1.44	d1.25	.96	d.37	d2.77	.54	.77	1.15	1.20	1.16	.72	.62	1.75	2.10	d.45	.60	Earnings per sh [A B]	1.10
	.40	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Nil	Nil	Div'ds Decl'd per sh	Nil
	2.78	1.32	.43	.94	1.64	1.74	1.10	2.66	4.08	2.58	3.21	5.56	5.72	2.62	3.05	5.06	4.10	4.50	Cap'l Spending per sh	4.00
	11.98	11.11	8.97	6.16	7.14	6.77	.81	1.16	6.59	8.74	11.51	12.56	12.19	14.16	16.38	18.28	15.40	15.90	Book Value per sh	17.85
	13.73	13.81	14.01	14.06	14.06	14.07	14.07	14.09	24.39	24.78	26.43	26.51	32.33	32.36	30.82	41.41	65.00	66.00	Common Shs Outst'g [C]	70.00
	--	--	--	--	9.4	--	--	10.5	13.0	8.2	9.6	12.6	22.0	21.0	5.9	6.1	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	8.0
	--	--	--	--	.70	--	--	.62	.85	.55	.60	.73	1.14	1.20	.38	.31			Relative P/E Ratio	.55
	4.0%	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--			Avg Ann'l Div'd Yield	Nil
							946.5	831.0	871.2	970.2	975.4	943.5	1490.3	3000.3	5103	5216	6850	7250	Sales ($mill) [A]	7500
							1.5%	6.9%	9.3%	10.2%	11.2%	11.1%	11.6%	4.6%	4.0%	4.9%	3.5%	4.5%	Operating Margin	5.5%
							16.6	22.6	36.1	42.6	41.5	45.7	66.0	40.5	45.5	57.4	110	120	Depreciation ($mill)	150
							d29.8	17.0	20.4	28.6	31.8	30.7	27.3	32.2	73.3	88.0	d25.0	40.0	Net Profit ($mill)	75.0
							--	9.1%	21.5%	2.1%	37.5%	37.5%	46.9%	37.1%	40.6%	40.1%	40.0%	40.0%	Income Tax Rate	40.0%
							NMF	2.0%	2.3%	2.9%	3.3%	3.3%	1.8%	1.1%	1.4%	1.7%	NMF	.5%	Net Profit Margin	1.0%
							122.6	124.5	85.9	77.4	99.4	74.3	182.4	290.0	247.8	339.5	450	450	Working Cap'l ($mill)	475
							116.6	180.7	192.2	155.0	79.3	115.3	531.4	390.2	308.8	1112.5	2100	2200	Long-Term Debt ($mill)	2500
							122.4	138.6	160.7	216.5	304.1	333.0	559.2	623.1	689.9	757.0	1000	1050	Shr. Equity ($mill)	1250
							NMF	7.6%	8.4%	10.5%	10.3%	7.5%	4.0%	4.9%	9.1%	6.1%	2.0%	3.5%	Return on Total Cap'l	4.0%
							NMF	12.4%	12.7%	13.2%	10.4%	9.2%	4.9%	5.2%	10.9%	11.6%	NMF	4.0%	Return on Shr. Equity	8.0%
							NMF	47.4%	11.6%	13.2%	10.4%	9.2%	6.2%	3.8%	12.7%	10.4%	NMF	4.0%	Retained to Com Eq	6.0%
							NMF	54%	8%	--	--	--	11%	47%	12%	10%	Nil	Nil	All Div'ds to Net Prof	Nil

CAPITAL STRUCTURE as of 3/31/02
Total Debt $1251.4 mill. Due in 5 Yrs $300.0 mill.
LT Debt $1217.4 mill. LT Interest $95.0 mill.
(LT Interest earned: 3.6x; total interest coverage: 3.2x) (56% of Cap'l)

Leases, Uncapitalized Annual rentals $15.9 mill.
Pension Liability None
Pfd Stock None

Common Stock 64,545,011 shs. (44% of Cap'l)
MARKET CAP: $400 million (Small Cap)

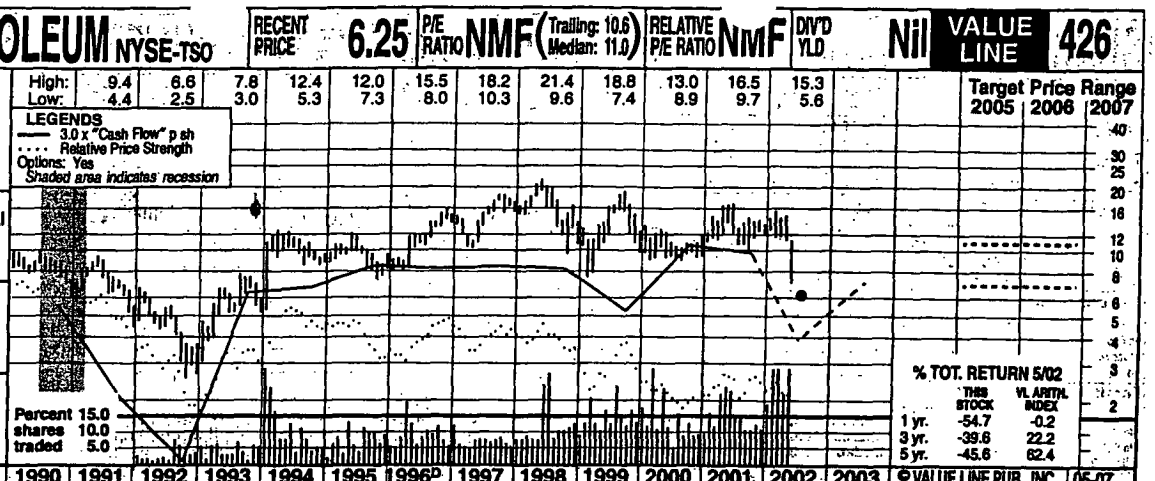
CURRENT POSITION ($MILL.)	2000	2001	3/31/02
Cash Assets	14.1	51.9	2
Receivables	334.5	384.9	434.7
Inventory (LIFO)	274.3	431.8	418.6
Other	7.3	9.4	14.9
Current Assets	630.2	878.0	868.4
Accts Payable	378.6	331.2	381.5
Debt Due	3.8	34.4	34.0
Other		172.9	150.5
Current Liab.	382.4	538.5	566.0

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Sales	6.5%	28.0%	8.0%
"Cash Flow"	11.0%	2.0%	9.0%
Earnings		7.5%	9.0%
Dividends			Nil
Book Value	9.5%	12.5%	13.0%

Calendar	QUARTERLY SALES ($ mill.) [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	508.6	754.0	888.0	849.7	3000.3
2000	1055	1218	1394	1436	5103
2001	1227	1299	1412	1278	5216
2002	1243	1850	1900	1857	6850
2003	1800	1825	1825	1800	7250

Calendar	EARNINGS PER SHARE [A B] Mar.31	Jun.30	Sept.30	Dec.31	Full Year
1999	d.09	.76	.53	d.82	E.62
2000	.21	.35	.60	.59	1.75
2001	.51	.70	.79	.10	E2.10
2002	d1.00	d.20	.50	.25	d.45
2003	.10	.20	.20	.10	.60

Calendar	QUARTERLY DIVIDENDS PAID Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998					
1999					
2000	NO CASH DIVIDENDS BEING PAID				
2001					
2002					



BUSINESS: Tesoro Petroleum Corporation refines and markets petroleum products and provides marine services in the Gulf of Mexico and the West Coast. Operates 677 retail stations. Refineries located in Kenai, Alaska, Oahu, HI, Anacortes, WA, Salt Lake City, UT, Mandan, ND, and San Francisco, CA. Acquired CA refinery 5/02; ND, 9/01; UT, 9/01; HI, 5/98; WA, 8/98. Divested E&P operations, 12/99. 2001 refinery throughput 290,000 bbl./day (74.4% of capacity). Has about 3,300 employees; 3,500 shareholders. Officers and directors own 5.4% of common stock (5/02 Proxy). President & CEO: Bruce Smith. Incorporated: Delaware. Address: 8700 Tesoro Dr., San Antonio, TX 78217. Telephone: 210-828-8484. Internet: www.tesoropetroleum.com.

Tesoro Petroleum has completed the purchase of the Golden Eagle, CA, refinery from Valero. Terms of the transaction were altered at the last minute to stave off concerns that Tesoro might face liquidity problems, given the precipitous decline in West Coast refining margins and the company's lofty debt load. In the end, Tesoro paid $1.075 billion for the assets, $50 million less than it originally planned. Valero also agreed to loan Tesoro $150 million with a below-market interest rate and contribute an additional $25 million to an ongoing capital improvement project. The deal was mostly financed with debt, boosting Tesoro's debt-to-capital ratio close to 70%, and at a time when there is significant uncertainty regarding the outlook for refining margins. By amending the transaction and reducing capital spending plans for the rest of the year, the company was able to avoid tapping its $250 million revolving credit facility, leaving some financial flexibility if operating conditions worsen.

Tesoro has aggressively acquired refining and marketing facilities during the past few years as part of a plan to become an industry leader. Debt levels have swelled as a result. Refining margins were well above average during much of the expansion period, enabling it to generate enough cash flow to cover its needs. But when margins plummeted in the first quarter, the company borrowed to cover its operating expenses. Leverage is even higher now, and although tougher environmental standards are likely to benefit margins in California, we think that spreads will remain volatile, potentially exposing the company to significant liquidity risk.

Tesoro shares are a highly speculative proposition at this juncture. If industry conditions remain consistently strong over the next several years, our projections may well prove conservative. The ultracompetitive nature of the refining industry makes this far from a sure thing, however, and the hefty leverage adds substantial risk.

Noah Goldner *June 21, 2002*

CASH POSITION	5-Year Av'g	3/31/02
Current Assets to Current Liabilities:	177%	153%
Cash & Equiv's to Current Liabilities:	22%	NMF
Working Capital to Sales:	8%	6%

(A) Fiscal year ends Sep. 30th through fiscal 1991, Dec. 31st thereafter. (B) Primary egs. until 1996, basic egs. thereafter. Excludes losses (disc. ops.): '85, $7.72; '86, $9.53; Excludes net nonrecurr. gain/(loss): '88, (60¢); '89, ($1.58); '92, ($2.51); '94, (21¢); '95, $1.15; '96, $1.61; '97, 11¢; '98, ($1.58). Next egs. report due in late Jul. (C) In millions. (D) 1996 net profit and share net were $13.9 million and $0.53, respectively, excluding rev. from above-market pricing. (E) Earnings don't add due to changes in avg. number of shrs. outstanding.

Company's Financial Strength	C++
Stock's Price Stability	40
Price Growth Persistence	50
Earnings Predictability	30

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ENCANA ENERGY TSE-ECA.TO A

RECENT PRICE 45.10 | P/E RATIO 21.0 (Trailing: 13.0 / Median: 19.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 0.9% | VALUE LINE 431

TIMELINESS 4 Lowered 3/15/02
SAFETY 3 Lowered 12/25/98
TECHNICAL 3 Lowered 3/15/02
BETA .75 (1.00 = Market)

2005-07 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+55%)	13%
Low	45	(Nil)	1%

Insider Decisions

NOT REPORTED

U.S. Institutional Decisions

	3Q2001	4Q2001	1Q2002
to Buy	15	112	100
to Sell	0	6	96
Hld's(000)	4282	80634	178723

	High:	17.0	16.8	24.2	22.4	27.0	27.5	30.7	24.0	25.8	42.3	52.3	50.7	36.3
	Low:	11.2	11.5	16.6	18.5	18.5	23.0	20.6	16.0	15.0	19.5	35.1	36.3	

LEGENDS
— 7.0 x "Cash Flow" p sh
···· Relative Price Strength
2-for-1 split 5/97
Options: Yes
Shaded area indicates recession

Target Price Range: 2005 | 2006 | 2007

% TOT. RETURN 5/02

	THIS STOCK	VL ARITH. INDEX
1 yr.	—	-0.2
3 yr.	—	22.2
5 yr.	—	62.4

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
	2.71	2.72	2.71	3.13	3.79	3.39	3.79	4.44	5.84	7.29	10.86	12.87	11.78	15.38	28.32	39.43	16.85	18.85	Revenues per sh	25.95
	1.20	1.35	1.26	1.40	1.78	1.55	1.86	2.39	2.84	3.11	3.72	3.51	3.02	3.85	7.09	8.45	6.45	7.20	"Cash Flow" per sh	9.15
	.62	.73	.50	.53	.85	.55	.69	.93	1.15	1.01	1.29	1.31	.50	1.39	4.09	5.00	2.15	2.50	Earnings per sh B	3.95
	.35	.30	.30	.30	.30	.30	.30	.38	.40	.40	.40	.40	.40	.40	.40	.40	.40	.50	Div'ds Decl'd per sh C	.70
	.72	.88	1.16	1.21	1.36	1.44	1.20	2.34	3.41	3.85	3.01	4.51	3.51	3.28	5.55	7.63	6.30	6.75	Cap'l Spending per sh	8.10
	5.03	5.45	5.65	5.88	6.43	6.32	6.70	7.27	8.02	8.53	9.52	10.41	10.52	11.49	15.32	15.34	28.40	30.35	Book Value per sh	39.00
	249.82	249.80	249.80	249.80	249.82	249.82	249.84	250.34	250.48	250.84	251.16	251.67	251.72	251.77	254.83	254.94	475.00	478.00	Common Shs Outst'g D	482.00
	20.8	21.1	25.2	28.2	17.1	26.1	19.2	22.0	18.0	22.8	20.0	20.4	42.1	14.9	7.5	8.6	Bold figures are Value Line estimates.		Avg Ann'l P/E Ratio	16.0
	1.40	1.41	2.09	1.98	1.27	1.67	1.16	1.30	1.18	1.53	1.25	1.18	2.19	.85	.49	.44			Relative P/E Ratio	1.00
	2.7%	2.0%	2.4%	2.2%	2.1%	2.1%	2.3%	1.8%	1.9%	1.7%	1.6%	1.5%	1.9%	1.9%	1.3%	.9%			Avg Ann'l Div'd Yield	1.2%
							945.7	1110.3	1463.7	1829.0	2727.4	3238.6	2965.6	3873.0	7215.9	10052	8000	9000	Revenues ($mill)	12500
							61.6%	61.4%	57.0%	50.3%	39.7%	32.4%	29.9%	30.8%	35.3%	28.5%	38.0%	38.0%	Operating Margin	38.0%
							294.8	367.3	423.4	527.9	611.6	552.9	636.4	825.1	775.1	856.0	2000	2200	Depreciation ($mill)	2500
							170.6	231.0	287.3	252.8	323.8	329.7	124.7	350.3	1039.1	1304.0	1070	1240	Net Profit ($mill)	1900
							35.7%	22.5%	26.2%	28.8%	27.3%	26.8%	24.7%	27.5%	38.4%	33.3%	35.0%	35.0%	Income Tax Rate	35.0%
							18.0%	20.8%	19.6%	13.8%	11.9%	10.2%	4.2%	9.0%	14.4%	13.0%	13.4%	13.8%	Net Profit Margin	15.2%
							99.6	87.1	40.1	77.8	592.2	36.2	111.3	205.8	d63.5	151.0	390	750	Working Cap'l ($mill)	800
							352.8	283.0	472.3	862.2	897.8	1133.7	1381.1	1111.0	912.3	2118.0	7500	7600	Long-Term Debt ($mill)	8000
							1674.7	1818.9	2007.9	2140.4	2391.2	2819.4	2647.7	3017.8	4028.7	4038.0	13500	14500	Shr. Equity ($mill)	18800
							9.1%	11.7%	12.3%	9.4%	10.8%	9.7%	4.4%	9.6%	21.9%	22.0%	6.0%	6.5%	Return on Total Cap'l	8.0%
							10.2%	12.7%	14.3%	11.8%	13.5%	12.6%	4.7%	11.6%	25.8%	32.3%	8.0%	8.5%	Return on Shr. Equity	10.0%
							5.7%	7.5%	9.3%	7.1%	9.3%	8.7%	.9%	8.4%	23.8%	30.6%	6.0%	7.0%	Retained to Com Eq	9.0%
							44%	41%	35%	40%	31%	31%	81%	31%	11%	8%	18%	18%	All Div'ds to Net Prof	18%

CAPITAL STRUCTURE as of 3/31/02

Total Debt $7112.0 mill. Due in 5 Yrs $500.0 mill.
LT Debt $6895.0 mill. LT Interest $480.0 mill.
(LT Interest Earned: 20.0x) (35% of Cap'l)

Leases, Uncapitalized $163.0 mill.
Pension Liability None

Pfd Stock $586.0 mill. Pfd. Div'd $44.0 mill. (3% of Cap'l)
Common Stock 474,100,000 shs. (62% of Cap'l)

MARKET CAP: $21.4 billion (Large Cap)

CURRENT POSITION ($MILL.)	2000	2001	3/31/02
Cash Assets	197.3	963.0	605.0
Receivables	1312.4	841.0	1494.0
Inventory (Avg. Cost)	117.7	157.0	499.0	
Other	--	414.0	266.0
Current Assets	1627.4	2375.0	2864.0
Accts Payable	1217.9	990.0	1849.0
Debt Due	150.0	160.0	217.0
Other	323.0	1074.0	824.0
Current Liab.	1690.9	2224.0	2890.0

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Revenues	23.0%	28.0%	-1.0%
"Cash Flow"	15.0%	15.0%	6.0%
Earnings	18.5%	25.0%	2.0%
Dividends	3.0%	--	10.0%
Book Value	8.5%	10.0%	18.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	754.7	794.6	999.7	1324	3873.0
2000	1398	1445	1818	2553	7215.9
2001	3145	2707	2454	1746	10052
2002	2080	*1940*	*1960*	*2000*	*8000*
2003	*2000*	*2100*	*2400*	*2500*	*9000*

Calendar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	.15	.25	.40	.59	1.39
2000	.73	.84	1.17	1.35	4.09
2001	1.89	1.65	1.10	.36	5.00
2002	.36	*.55*	*.58*	*.66*	2.15
2003	*.60*	*.60*	*.65*	*.65*	*2.50*

Calendar	QUARTERLY DIVIDENDS PAID C Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	.10	.10	.10	.10	.40
1999	.10	.10	.10	.10	.40
2000	.10	.10	.10	.10	.40
2001	.10	.10	.10	.10	.40
2002	.10				

BUSINESS: EnCana Corp., formerly PanCanadia Energy Corp., explores for and produces crude oil, natural gas, natural gas liquids, and sulfur, primarily in western Canada, as well as offshore Canada, and the Gulf of Mexico. Net proven reserves at 3/31/01 (after royalty): conventional crude oil and natural gas liquids, 399 million barrels; natural gas, 2.9 billion cubic feet. 2001 daily production (after royalty): oil, 97.7 kbbls.; natural gas liquids, 13.5 kbbls.; natural gas 940 mmcf. Net landholdings: 24.6 mill. net acres (2.9 mill. developed and 21.9 undeveloped). '01 depr. rate, 5.8%. Has approx. 1,755 employees. Pres. & CEO: Gwyn Morgan. Inc.: Canada. Addr.: P.O. Box 2850, Calgary, Alberta, Canada T2P 2S5. Tel.: 403-290-2000. Internet Addr.: www.pancanadian.ca.

EnCana has resulted from the merger of PanCanadian Energy with Alberta Energy. The transaction was completed in early April, and the newly formed company has one of the largest exploration and production businesses in North America. The driller reported pro forma results of $0.36 per share for the first period. However, year-over-year comparisons are difficult, due to the merger, as well as the discontinuation of some midstream and marketing operations.

The company is integrating newly acquired operations well. There has been a reduction of staff by about 5%. And, there will likely be further reductions going forward. The company also plans to sell some of its assets, probably about $1 billion. The merger should generate significant cost savings, and lower some equipment and capital expenditures. EnCana's debt-to-capital level is at about 35%, which should allow the company to acquire companies without becoming overleveraged.

Production remains strong and will likely increase at about 6%-10% annually, going forward. On a pro forma basis, production of oil equivalents rose about 12% year over year. However, lower prices for most commodities have caused revenues to be a bit sluggish. Natural gas prices were weak and have declined almost 63%, year over year. And, oil prices, although rebounding a bit, still remain down about 12%, compared to the year-ago period. The company expects production to be about 60% oil projects, and about 40% natural gas, going forward. EnCana has a large base of assets, and recent acquisitions in the U.S. Rocky Mountains, should add to production capabilities.

We expect earnings to increase at about 15% annually over the next few years. The company has several projects, such as coal bed methane production, and power generation, that should add to its diversified energy production.

These shares have not moved much since our March report. This likely reflects investors' concern over the merger, as well as the volatility of energy prices. Our current projections indicate that these shares offer slightly below-average appreciation potential for the next 3- to 5-years.

Adam Rosner *June 21, 2002*

(A) All figures in Canadian dollars. (B) Based on avg. shrs. outstanding and Canadian acct'g. principles. Uses "full cost" acct'g. Excludes n/r losses: '88, 76¢; '91, 72¢; '95, 20¢. Excludes n/r gains: '96, 9¢; '98, 9¢. Next earnings report due late July. (C) Next dividend meeting about June 4th. Goes ex about Sep. 14th. Approximate dividend payment dates: Mar. 31st, June 30th, Sept. 30th, Dec. 29th. Dividend subject to 15% Canadian nonresident withholding tax. Spec. div. paid Sept. 01: $4.60. (D) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	65
Price Growth Persistence	45
Earnings Predictability	40

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MARATHON OIL NYSE-MRO

RECENT PRICE 25.90 | P/E RATIO 14.8 (Trailing: 9.6 Median: 22.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 3.6% | VALUE LINE 416

TIMELINESS 4 Lowered 12/28/01
SAFETY 3 New 8/16/91
TECHNICAL 4 Lowered 6/21/02
BETA .80 (1.00 = Market)

2005-07 PROJECTIONS

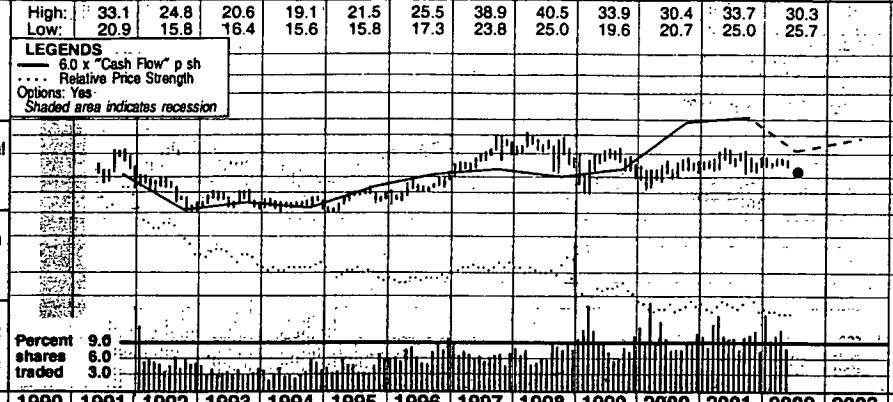
	Price	Gain	Ann'l Total Return
High	65	(+150%)	28%
Low	45	(+75%)	17%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	2	0
Options	0	0	0	0	0	0	0	1	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	3Q2001	4Q2001	1Q2002
to Buy	195	175	211
to Sell	175	194	168
Hld's(000)	237097	187820	201250



Target Price Range 2005 | 2006 | 2007

% TOT. RETURN 5/02

	THIS STOCK	VL ARITH. INDEX
1 yr.	-12.4	-0.2
3 yr.	-1.9	22.2
5 yr.	3.7	62.4

1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	© VALUE LINE PUB., INC.	05-07
--	--	38.41	47.98	57.43	53.90	44.60	41.74	44.49	48.26	56.81	54.25	71.56	78.02	96.86	91.60	*85.00*	*87.10*	Sales per sh A	*96.75*
--	--	3.94	5.53	5.97	4.14	2.70	2.99	2.79	3.61	4.22	4.49	4.09	4.44	7.65	8.25	*5.55*	*6.30*	"Cash Flow" per sh	*8.05*
--	--	.05	1.49	1.94	.78	d.07	.46	.30	.78	1.81	2.20	1.09	1.40	4.20	4.26	*1.75*	*2.40*	Earnings per sh BA	*3.60*
--	--	1.09	1.22	1.22	.70	1.22	.68	.68	.68	.70	.76	.84	.84	.88	.92	*.92*	*.94*	Div'ds Decl'd per sh Cm	*1.08*
--	--	3.36	4.04	3.93	3.70	4.16	3.18	2.63	2.23	2.61	3.59	4.12	4.42	4.62	5.30	*5.00*	*5.25*	Cap'l Spending per sh	*5.75*
--	--	13.25	13.92	12.40	11.36	10.58	11.03	9.99	11.62	12.53	13.98	15.39	15.72	15.97	*16.80*	*18.10*	Book Value per sh	*24.55*
--	--	259.03	255.58	254.51	259.26	286.61	286.58	286.73	287.40	287.50	288.80	308.50	311.80	308.30	309.40	*310.00*	*310.00*	Common Shs Outst'g D	*310.00*
--	--	--	--	14.8	34.4	--	39.8	58.1	23.9	11.7	14.1	30.5	20.3	6.2	6.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
--	--	--	--	1.10	2.20	--	2.35	3.81	1.60	.73	.81	1.59	1.16	.40	.35			Relative P/E Ratio	*1.00*
--	--	--	--	4.3%	2.6%	6.0%	3.7%	3.9%	3.7%	3.3%	2.5%	2.5%	3.0%	3.4%	3.2%			Avg Ann'l Div'd Yield	*2.0%*
12782	11962	12757	13871	16332	15668	22075	24327	29861	28340	*26350*	*27000*	Sales ($mill)	*30000*						
10.4%	9.5%	9.0%	10.9%	10.5%	11.5%	9.7%	8.7%	12.6%	14.9%	*11.5%*	*12.5%*	Operating Margin	*13.5%*						
793.0	727.0	721.0	817.0	693.0	664.0	941.0	950.0	1052.0	1236.0	*1175*	*1250*	Depreciation ($mill)	*1375*						
d14.0	136.0	86.0	224.1	520.0	633.5	321.0	434.0	1308.0	1318.0	*545*	*700*	Net Profit ($mill)	*1120*						
---	---	38.1%	43.8%	32.9%	33.7%	29.0%	34.0%	38.6%	36.5%	*40.0%*	*38.0%*	Income Tax Rate	*36.0%*						
NMF	1.1%	.7%	1.6%	3.2%	4.0%	1.5%	1.8%	4.4%	4.7%	*2.1%*	*2.6%*	Net Profit Margin	*3.7%*						
d344.0	d70.0	25.0	d137.0	d96.0	d244.0	366.0	953.0	973.0	943.0	*915*	*900*	Working Cap'l ($mill)	*925*						
3743.0	4239.0	3983.0	3367.0	2642.0	2476.0	3456.0	3320.0	1937.0	3432.0	*4350*	*4000*	Long-Term Debt ($mill)	*3500*						
3335.0	3110.0	3241.0	2872.0	3340.0	3618.0	4312.0	4800.0	4845.0	4940.0	*5205*	*5620*	Shr. Equity ($mill)	*7610*						
1.9%	4.5%	3.6%	6.0%	11.2%	12.2%	5.9%	7.2%	21.0%	16.8%	*7.5%*	*8.5%*	Return on Total Cap'l	*10.5%*						
NMF	4.4%	2.7%	7.6%	15.6%	17.5%	7.4%	9.0%	27.0%	26.7%	*10.5%*	*12.5%*	Return on Shr. Equity	*14.5%*						
NMF	NMF	NMF	.9%	9.6%	11.5%	1.7%	3.7%	21.3%	19.8%	*5.0%*	*7.5%*	Retained to Com Eq	*10.5%*						
NMF	NMF	NMF	89%	39%	35%	77%	59%	21%	26%	*53%*	*39%*	All Div'ds to Net Prof	*30%*						

CAPITAL STRUCTURE as of 3/31/02
Total Debt $4557.0 mill. Due in 5 Yrs $1607.0 mill.
LT Debt $4341.0 mill. LT Interest $275.0 mill.
(Total interest coverage: 8.3x) (47% of Cap'l)

Leases, Uncapitalized Annual rentals $116.0 mill.
Pension Liability None
Pfd Stock None

Common Stock 309,705,270 shs. (53% of Cap'l)
as of 4/30/02
MARKET CAP: $8.0 billion (Large Cap)

CURRENT POSITION

($MILL.)	2000	2001	3/31/02
Cash Assets	340.0	657.0	237.0
Receivables	2267.0	1772.0	1831.0
Inventory (LIFO)	1867.0	1851.0	1991.0
Other	511.0	131.0	191.0
Current Assets	4985.0	4411.0	4250.0
Accts Payable	3021.0	2431.0	2540.0
Debt Due	148.0	215.0	216.0
Other	843.0	822.0	587.0
Current Liab.	4012.0	3468.0	3343.0

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '99-'01 to '05-'07
Sales	5.5%	12.0%	*1.5%*
"Cash Flow"	2.5%	14.0%	*3.0%*
Earnings	9.0%	28.0%	*1.5%*
Dividends	-1.5%	5.0%	*3.5%*
Book Value	2.0%	7.5%	*7.5%*

QUARTERLY SALES ($ mill.) A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	4851	5481	6490	7505	24327
2000	6740	7687	8036	7398	29861
2001	7613	7974	7119	5634	28340
2002	6409	*6650*	*6600*	*6691*	*26350*
2003	*6700*	*6800*	*6700*	*6800*	*27000*

EARNINGS PER SHARE B

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1999	d.03	.39	.57	.47	1.40
2000	.83	1.18	1.14	1.25	4.20
2001	1.64	1.88	.62	.12	4.26
2002	.09	*.55*	*.50*	*.61*	*1.75*
2003	*.60*	*.60*	*.55*	*.65*	*2.40*

QUARTERLY DIVIDENDS PAID Cm

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	.21	.21	.21	.21	.84
1999	.21	.21	.21	.21	.84
2000	.21	.21	.23	.23	.88
2001	.23	.23	.23	.23	.92
2002	.23	.23			

BUSINESS: Marathon Oil Corporation is an integrated oil company. Daily 2001 production: oil, 209,000 barrels; natural gas, 1.3 billion cubic feet. Reserves at 12/31/01: 570 million barrels of oil; 2.9 trillion cubic feet of natural gas. Average 5-yr. finding costs: $6.95 per bbl. (vs. ind. avg. $4.28). 5-yr. reserve replacement rate, 107% (vs. ind. avg. 145%). Daily refining capacity, 935,000 bbls. Markets to 5,970 stations. Capital employed by segment: Upstream, 56%; Downstream, 42%; Other, 2%. Has 30,671 employees. Barclay's, Capital Securities owns 6.9% of stock; Capital Research, 5.9% (4/02 Proxy). Chairman: Thomas Usher. CEO & President: Clarence Cazelot, Jr. Inc.: DE. Address: 5555 San Felipe Rd. Houston, TX 77056. Tel.: 713-296-4129. Internet: www.marathon.com.

Marathon Oil stock shows few signs of soon being able to break out of the trading range it has been in since 1996. Earnings volatility is a big factor. Share net in 2002 will likely approximate the level of six years past, albeit with wide swings in between. Poor pricing conditions in this year's first quarter, which gave rise to weak earnings, reinforce the notion that Marathon's bottom line is largely captive to forces beyond its control.

Earnings should nevertheless perk up over the next 18 months. That's essentially due to improved price realizations, of course, both at the gasoline pump, and for Marathon's oil and natural gas production. Overall, oilfield production should be flat in 2002, unless Marathon can make some more acquisitions. There's greater profit potential in 2003, assuming margins hold up and the company makes headway with its drilling program.

Marathon Oil is relying on a recent large acquisition and some fill-in projects to sustain growth. The $1 billion, January purchase of natural gas interests in Equatorial Guinea will shore up hydrocarbon reserves nicely for the next few years, reversing a downtrend in this area. The move has sizable expansion potential, and, in conjunction with investments in the Rockies, Alaska, Norway, and the Gulf of Mexico, may lead to moderately higher production down the road.

The rise in financial leverage is a burden. It will take a few years to pay down the debt taken on to pay for this year's big purchase and to consummate the split-up with U.S. Steel. Marathon still enjoys very good cash flow, though, and we don't see a threat to its credit rating at this juncture.

The shares offer good long-term possibilities. In addition to changeable business conditions, the stock has been held back by asset writedowns and a lack of drilling success. Assuming Marathon can get some growth out of its development projects, find more oil, avoid writeoffs, and keep its refining division running smoothly, earnings, and the stock price, should benefit. The dividend should also rise in time, and the yield, well above average, contributes to very respectable total return potential out to 2005-2007. But the stock is untimely for the months ahead.

Robert Mitkowski, Jr. *June 21, 2002*

(A) Excludes excise taxes starting in 2000.
(B) Primary earnings until 1996, then diluted. 1990 figures are pro forma; Excludes nonrecurring gains (charges): '91, ($1.09); '92, (73¢); '93, (58¢); '94, 80¢; '95, ($1.11); '96, 52¢; '97, (61¢); '98, (4¢); '99, 71¢; '00, ($2.81); '01, ($3.12). Next earnings report due late July.
(C) Next dividend meeting late Jul. Goes ex mid-Aug. Dividend payment dates: on or about the 10th of March, June, September, December. ■Dividend reinvestment plan available.
(D) In millions.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	40
Earnings Predictability	40

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Electric & Gas Utilitiies
Percent Regulated Revenue

Company Name	Total Revenue	Regulated Electric Revenue	Regulated Gas Revenue	Percent Regulated Revenue
Allegheny Energy	4,012	2,507	*	62.5%
Alliant Energy	**2,405**	**1,648**	**415**	**85.8%**
Ameren	**3,856**	**3,526**	**324**	**99.8%**
Cinergy Corp	8,421	2,692	429	37.1%
Consolidated Edison Inc.	**9,431**	**6,938**	**1,262**	**86.9%**
Constellation Energy Group	3,878	2,052	502	65.9%
DPL Inc (Dayton Power & Light)	**1,437**	**1,090**	**184**	**88.7%**
DTE Energy	5,597	4,129		73.8%
Dominion Resources (Va. Power)	9,260	4,492	1,374	63.3%
Energy East	**2,960**	**2,024**	**772**	**94.5%**
Entergy Corp	10,016	7,220	166	73.7%
Madison Gas & Electric	**324**	**203**	**121**	**100.0%**
NI Source	6,031	1,557	1,807	55.8%
NorthWestern Corp.	7,132	87	95	2.6%
PPL Electric Utilities Corp	5,683	3,167	*	55.7%
Progress Energy	**4,119**	**3,565**	**324**	**94.4%**
Puget Sound Energy	**3,442**	**2,772**	**612**	**98.3%**
Reliant Energy	29,339	5,494	*	18.7%
Rochester Gas & Electric	1,448	731	340	74.0%
SCANA Corp(Pub Ser of NC, SC Elect. & Gas)	3,433	1,344	998	68.2%
Sempra Energy	7,143	2,184	3,305	76.8%
Sierra Pacific	**2,334**	**2,219**	**101**	**99.4%**
TXU Corp	22,009	4,752	962	26.0%
TECO Energy (Tampa Electric Co.& Peoples G	2,295	1,354	314	72.7%
UGI Corp.(UGI Utilities)	1,762	78	359	24.8%
Utilicorp-	28,975	1,208	826	7.0%
Vectren Corp	1,649	336	819	70.0%
Wisconsin Electric Power (Wisconsin Energy)	3,355	2,557	*	76.2%
WPS	1,951	625	265	45.6%
Xcel Energy (No. States Power)	11,592	6,492	1,466	68.7%
MDU Resources Group	1,874	162	233	21.1%

*Electric and gas revenues not separately identified.

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Electric & Gas Utilities percent regulated revenue
by Public Service Commission
Exhibit # 17
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike

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MDU Utilities Company
Working Capital, Dec 2000 - Dec 2001
(thousands of Dollars)

	Materials & Supplies	Fuel Stocks	Pre-payments	Customer Advances	Net Working Capital	% Variance
December	421	23	17	-486	-25	-120.8%
January	401	26	2	-482	-53	-144.2%
February	400	23	7	-477	-47	-139.2%
March	412	22	8	-484	-42	-135.0%
April	447	21	-6	-435	27	-77.5%
May	456	13	26	-432	63	-47.5%
June	494	16	87	-433	164	36.7%
July	469	11	75	-280	275	129.2%
August	486	26	75	-281	306	155.0%
Septembe	467	29	63	-281	278	131.7%
Ocfober	449	29	48	-279	247	105.8%
November	418	23	36	-267	210	75.0%
December	382	19	22	-268	155	29.2%
Average	439	22	35	-376	120	

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MDU-Working Capital, Dec 2000 - Dec 2001
by Public Service Commission
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PROSPECTUS

$150,000,000
Secured Medium-Term Notes
MDU RESOURCES GROUP, INC.

MDU Resources Group, Inc. (the "Company") intends from time to time to offer up to $150,000,000 aggregate principal amount of its Secured Medium-Term Notes (the "Notes") as an additional series of the Company's first mortgage bonds having maturities ranging from 9 months to 35 years from the date of issuance. Each Note will bear interest at a rate determined by the Company at or prior to the sale thereof. The aggregate principal amount, interest rate, interest payment dates, purchase price, maturity and redemption terms, if any, of each issue of the Notes will be set forth in a Prospectus Supplement or Prospectus Supplements (the "Prospectus Supplement") including Prospectus Supplements to be filed with respect to each issuance and sale of Notes. The terms upon which each issuance and sale of Notes are offered, together with the names of the agents (the "Agents") and the Agents' commissions or discounts, if applicable, will also be set forth in Prospectus Supplements.

THESE SECURITIES HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE SECURITIES AND EXCHANGE COMMISSION OR ANY STATE SECURITIES COMMISSION NOR HAS THE SECURITIES AND EXCHANGE COMMISSION OR ANY STATE SECURITIES COMMISSION PASSED UPON THE ACCURACY OR ADEQUACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

The Company may sell the Notes through underwriters, dealers or agents, or directly to one or more purchasers. The Prospectus Supplement will set forth the names of underwriters, dealers or agents, if any, any applicable commissions or discounts and the net proceeds to the Company from the sale of the Notes. See "Plan of Distribution" for possible indemnification and contribution arrangements for the Agents.

The date of this Prospectus is April 6, 1992

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MDU Resources Group, Inc. $150,000
note - prospectus
by Public Service Commission
Exhibit # 14
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AVAILABLE INFORMATION

The Company is subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and in accordance therewith files reports, proxy statements and other information with the Securities and Exchange Commission (the "Commission"). Such reports, proxy statements and other information can be inspected and copied at the public reference facilities maintained by the Commission at 450 Fifth Street, N.W., Washington, D.C. and at its regional offices at 75 Park Place, New York, N.Y. and 500 West Madison Street, Chicago, Ill. Copies of such materials can be obtained from the Public Reference Section of the Commission at 450 Fifth Street, N.W., Washington, D.C. 20549 at prescribed rates. Such reports, proxy statements and other information can also be inspected at the offices of the New York Stock Exchange, Inc., on which certain of the Company's securities are listed.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The following document filed by the Company with the Commission under the Exchange Act is incorporated herein by reference:

The Company's Annual Report on Form 10-K for the year ended December 31, 1991.

All documents subsequently filed by the Company pursuant to Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act prior to the termination of the offering of the Notes shall be deemed to be incorporated by reference herein and to be a part hereof from the date of filing of such documents.

The Company hereby undertakes to provide without charge to each person, including any beneficial owner, to whom a copy of this Prospectus is delivered, upon written or oral request of any such person, a copy of any or all of the documents referred to above which have been or may be incorporated by reference in this Prospectus, other than exhibits to such documents not specifically incorporated by reference herein. Requests for such copies should be directed to Office of the Treasurer, MDU Resources Group, Inc., 400 North Fourth Street, Bismarck, North Dakota 58501, telephone (701) 222-7900.

THE COMPANY

The Company is a diversified natural resource company which was incorporated under the laws of the State of Delaware in 1924. Its principal executive offices are at 400 North Fourth Street, Bismarck, North Dakota 58501, telephone (701) 222-7900.

Montana-Dakota Utilities Co., the public utility division of the Company, provides electric and/or natural gas distribution service at retail in North Dakota, eastern Montana, northern and western South Dakota and northern Wyoming, and owns and operates electric power generation and transmission facilities. The Company, through its wholly-owned subsidiary, Centennial Energy Holdings, Inc., owns Williston Basin Interstate Pipeline Company ("Williston Basin"), Knife River Coal Mining Company ("Knife River"), the Fidelity Oil Group (comprised of Fidelity Oil Co., Fidelity Oil Holdings, Inc., and High Plains Gas Company) and Prairielands Energy Marketing, Inc. ("Prairielands"). Williston Basin produces natural gas and provides wholesale natural gas sales, underground storage and transportation services through an interstate pipeline system serving Montana, North Dakota, South Dakota and Wyoming. Knife River surface mines and markets low sulfur lignite coal. The Fidelity Oil Group owns oil and natural gas interests in the western United States, the Gulf Coast and Canada through investments with several oil and natural gas producers, and holds a minority equity position in one of those producers. Prairielands seeks new energy markets as well as methods to enhance and retain present markets for natural gas, which include buying, selling and arranging transportation services to end users, pipelines and local distribution companies.

FINANCING PROGRAM

Depending upon market conditions, the Company expects to offer all or a portion of the Notes and/or first mortgage bonds up to a maximum aggregate principal amount of $150,000,000. The Company also expects to have short-term borrowings outstanding from time to time during such period.

CERTAIN FINANCIAL INFORMATION(1)
(Dollars in Thousands)

	Years Ended December 31,		
	1989	1990	1991
Income Summary:			
Operating revenues	$343,502	$334,077	$367,311
Operating income	84,715	78,433	85,303
Net income	36,740	27,927	38,017

	December 31, 1991	
	Amount	%
Capital Structure:		
Long-term debt (including unamortized net discount)	$222,923	41.5
Preferred stock (including premium)	17,400	3.2
Common stock	296,605	55.3
Total(2)	$536,928	100.0

(1) This information should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 1991.

(2) Includes obligations due within one year. Does not reflect the redemption by the Company on March 18, 1992, of $1.0 million of its First Mortgage 7¾% Sinking Fund Bonds, due October 15, 1992, and $9.4 million of its First Mortgage Bonds, 7⅛% Series due November 1, 1993.

RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth the consolidated Ratio of Earnings to Fixed Charges for the periods indicated:

Years Ended December 31,				
1987	1988	1989	1990	1991
2.10	2.25	2.37	1.99	2.49

The Ratio of Earnings to Fixed Charges represents, on a pretax basis, the number of times earnings cover fixed charges. Earnings consist of net income, to which have been added fixed charges and taxes based on income. Fixed charges consist of interest on funded indebtedness, other interest, amortization of net discount on debt and the interest portion of all rentals charged to income.

USE OF PROCEEDS

Unless otherwise set forth in a Prospectus Supplement, the net proceeds from the sale of the Notes will be used to retire certain of the Company's outstanding senior securities, including the refunding of outstanding first mortgage bonds, and for other general corporate purposes.

PLAN OF DISTRIBUTION

The Notes may be offered on a continuing basis by the Company through the Agents, each of which will agree to use its reasonable efforts to solicit offers to purchase the Notes. The Company may also sell the Notes to any of the Agents at negotiated discounts for its own account or for resale to one or more investors at varying

prices related to prevailing market prices at the time of resale, as determined by such Agent, or for resale to one or more dealers at a discount, as determined by such Agent.

The Agents with respect to the offer and sale of any issue of the Notes will be named in the Prospectus Supplement relating thereto. The Prospectus Supplement will also describe the discounts and commissions to be allowed or paid to the Agents.

Under agreements which may be entered into by the Company with the Agents, Agents who participate in the distribution of the Notes may be entitled to indemnification by the Company against certain liabilities, including liabilities under the Securities Act of 1933, or to contribution by the Company with respect to payments which the Agents may be required to make in respect thereof.

DESCRIPTION OF NOTES

General

The Notes constitute a series of first mortgage bonds under and secured by an Indenture of Mortgage dated as of May 1, 1939, from the Company to The New York Trust Company and A.C. Downing (The Bank of New York, successor Corporate Trustee, W.T. Cunningham, successor Individual Trustee), as Trustees, and indentures supplemental thereto, including the Forty-fifth Supplemental Indenture which contains a Restatement of the Indenture, and which may include one or more supplemental indentures relating to the Notes, all of which are collectively referred to as the "Indenture." All of the first mortgage bonds issued and outstanding under the Indenture, including the Notes, are hereinafter referred to as "First Mortgage Bonds."

The Notes will be issuable only in registered form, without coupons, in denominations of $10,000 and integral multiples thereof and will be exchangeable for other Notes of the same series with the same interest rate, maturity and other terms, in equal aggregate amounts. No service charge will be made to holders of Notes for any transfer or exchange of Notes, but the Company may require payment of a sum sufficient to cover any tax or governmental charge incident to the transfer or exchange. Transfers and exchanges of Notes may be made at the Corporate Trust Office of The Bank of New York, New York, New York.

Reference is made to the Prospectus Supplement for the following terms relating to each of the Notes (among others): (i) the designation, series and aggregate principal amount of the Notes; (ii) the percentage of their principal amount at which such Notes will be issued; (iii) the date on which the Notes will mature; (iv) the rate per annum at which the Notes will bear interest; (v) the dates on which such interest will be payable; (vi) the place where the principal of and interest on the Notes will be payable; (vii) redemption terms, if any; and (viii) any other terms or provisions relating to such Notes which are not inconsistent with the provisions of the Indenture.

The following statements are, in part, summaries of certain provisions contained in the Indenture and do not purport to be complete. Certain of the terms used herein without definition are defined in the Indenture, to which reference is made for a complete statement of the terms and conditions of the Notes.

Redemption of Notes. Reference is made to the Prospectus Supplement for the redemption terms of the Notes, if any. If, at the time notice is given, the redemption monies are not on deposit with the Corporate Trustee, the redemption may be made subject to their receipt on or before the date fixed for redemption and such notice shall be of no effect unless such monies are received. (45th Supp. Ind., Part II, Art. V.)

Security. In the opinion of General Counsel for the Company, the Notes will be secured, together with all other First Mortgage Bonds now or hereafter issued under the Indenture, by a valid and direct first mortgage lien on substantially all of the fixed properties owned and all franchises held by the Company, subject to the lien of taxes for the current year and the lien of taxes and assessments not yet delinquent and to certain exceptions and reservations which do not, in the opinion of such counsel, materially affect the Company's title to or its right to use such properties. There are excepted from the lien cash, receivables and securities (including the capital stock of Centennial, Williston Basin, Knife River, the companies comprising the Fidelity Oil Group, Prairielands and any other subsidiaries); certain contracts; merchandise, appliances, materials or supplies; electric energy, gas, steam and certain other products; and automobiles, tractors, ships,

railroad cars and aircraft and various other transportation equipment. The property of subsidiaries, including Centennial, Williston Basin, Knife River, the companies comprising the Fidelity Oil Group and Prairielands, is not subject to the lien of the Indenture. The Company may release property subject to the lien of the Indenture against various credits, including property which is already also subject to the lien, but which has not yet been used as a credit under any provisions of the Indenture. Property not used as the basis for the issuance of First Mortgage Bonds or otherwise as a credit under the Indenture may in effect be released without substitution of equivalent property. The Company has released basically all of its gas production and pipeline-related property (but not its gas distribution property) from the lien of the Indenture and has transferred such property to Williston Basin. The Trustee has a security interest in certain of such property transferred as a result of related purchase money mortgages.

The Indenture contains provisions for subjecting to the lien thereof property which the Company may hereafter acquire, subject to liens existing thereon at the date of acquisition, and to limitations in the case of consolidation, merger or sale of substantially all of the Company's assets. (Orig. Ind., Granting Clauses; 45th Supp. Ind., Part II, Art. XII.)

Issuance of Additional Bonds. The Company may issue additional First Mortgage Bonds ranking equally with the Notes in a principal amount equal to (a) 70% of the net bondable value of property additions acquired by the Company, (b) the amount of cash deposited with the Corporate Trustee, and (c) the amount of refundable First Mortgage Bonds surrendered to the Corporate Trustee. (45th Supp. Ind., Part II, Secs. 3.04, 3.05 and 3.06.)

The Notes will be issued against property additions, refunded First Mortgage Bonds and/or the deposit of cash. On December 31, 1991, the Company had approximately $52.5 million of available property additions and $85.7 million of refunded First Mortgage Bonds. See "Description of Notes-Seeurity."

With certain exceptions in the case of (c) above, additional First Mortgage Bonds may be issued only if net earnings of the Company available for interest after depletion, as defined in the Indenture, for any twelve consecutive calendar months within the fifteen calendar months immediately preceding the month in which the application for such additional First Mortgage Bonds is made, are in the aggregate equal to at least two times the amount of the annual stated interest charges on all First Mortgage Bonds thereafter to be outstanding, and on all permitted equal or prior lien debt, if any. (45th Supp. Ind., Part II, Secs. 1.01 and 3.03.) For the twelve months ended December 31, 1991, the net earnings of the Company available for interest after depletion were $62.6 million or 3.8 times the annual stated interest charges on all First Mortgage Bonds and permitted equal or prior lien debt outstanding on that date, which would have permitted the Company to issue approximately $175.0 million of First Mortgage Bonds.

Property available for use as property additions includes property useful in the energy business in any form (other than gas but including gas distribution property) and water and steam heat property. Such property may be located anywhere in the United States of America or its coastal waters and may also include space satellites (including solar power satellites), space stations and other analogous facilities. (45th Supp. Ind., Part II, Sec. 1.01.)

Restrictions on Dividends. So long as any of the Notes are outstanding, the Company may declare and pay dividends in cash or property on its common stock only out of Surplus, as defined, or out of net profits for the fiscal year or the preceding fiscal year. However, the Company may not pay dividends out of net profits if the Capital of the Company, as defined, has been diminished to a specified extent.

Maintenance and Depreciation Provisions. The Company is required to make such expenditures as shall be necessary to maintain the mortgaged property in good repair, except that the Company may abandon any property, and to make provisions for depreciation and for depletion of depletable fixed assets in accordance with good accounting practices and in accordance with any applicable rules of any regulatory authority having jurisdiction. (45th Supp. Ind., Part II, Sec. 6.06.)

Modification of the Indenture. Modifications of the terms of the Indenture may be made with the consent of the Company by an affirmative vote of at least 60% in principal amount of outstanding First Mortgage

Bonds and of at least 60% in principal amount of outstanding First Mortgage Bonds of any series especially affected by such modification; but no such modification may be made which will affect the terms of payment of the principal at maturity of, or interest on, any First Mortgage Bond. (45th Supp. Ind., Part II, Art. XV.)

Events of Default. "Events of default" include the failure to pay principal, failure for 30 days to pay interest or to make any required deposit in any fund for the purchase or redemption of First Mortgage Bonds (including any sinking fund or improvement and sinking fund), failure for 90 days after written notice to perform any other covenant, and various events in bankruptcy or insolvency. (45th Supp. Ind., Part II, Art. IX.)

The Trustees are required to give notice to Bondholders of any continuing event of default known to them, but other than for a default in the payment of principal or interest or a sinking fund installment, the Trustees may withhold such notice if the responsible officers of the Corporate Trustee in good faith determine that such withholding is in the interests of the Bondholders. (45th Supp. Ind., Part II, Sec. 13.03.)

The Company must file an annual certificate with the Corporate Trustee as to compliance with the Indenture.

Concerning the Trustees. In the regular course of business, the Company may obtain short-term funds from several banks, including The Bank of New York. For information relating to the issuance of letters of credit by The Bank of New York on behalf of Centennial in connection with a 1989 settlement agreement effected with Atlantic Richfield Company related to certain contract litigation, see "Liquidity and Capital Commitments" in the Company's Annual Report on Form 10-K for the year ended December 31, 1991.

EXPERTS

The Company's consolidated financial statements incorporated in this Prospectus by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 1991, have been audited by Arthur Andersen & Co., independent public accountants, as set forth in their report incorporated therein, and are incorporated herein in reliance upon such report and upon the authority of said firm as experts in auditing and accounting.

The information set forth in the estimates dated January 9 and 21, 1992, of Ralph E. Davis Associates, Inc. concerning natural gas reserves and oil reserves incorporated by reference in the Company's Annual Report on Form 10-K for the year ended December 31, 1991, has been reviewed and verified by Ralph E. Davis Associates, Inc. and has been incorporated herein in reliance upon the authority of said firm as experts.

The information set forth in the report dated January 20, 1989, of Paul Weir Company Incorporated relating to lignite coal reserves of Knife River incorporated by reference in the Company's Annual Report on Form 10-K for the year ended December 31, 1991, has been reviewed and verified by Paul Weir Company Incorporated and has been incorporated herein in reliance upon the authority of said firm as experts.

LEGAL OPINIONS

The validity of the Notes will be passed upon for the Company by Lester H. Loble, II, Esq., General Counsel for the Company, and also by Reid & Priest, 40 West 57th Street, New York, New York 10019, and for any Agent by Berlack, Israels & Liberman, 120 West 45th Street, New York, New York 10036. Reid & Priest and Berlack, Israels & Liberman will rely on Lester H. Loble, II, Esq. with respect to matters of local law.

Public Utilities Reports
Advance Sheets

December 15, 2001 Index to Cases Reported appears on page x.

Authorized Rate of Return On Common Equity: An Annual Survey of Gas and Electric Rate Proceedings

Introduction

The following pages present the results of our latest annual survey of authorized rates of return on common equity (ROE) for state-regulated energy utilities. This year's survey covers orders issued by state regulatory commissions during the period October 1, 2000 through September 30, 2001. The survey reports the results of traditional, cost-of-service rate filings, as well as generic ROE proceedings, price regulation plans, and merger-related rate agreements. The reported ROE figures were obtained from a variety of sources, including rate analysts at state public utility commissions, rate department personnel at major, investor-owned electric and gas utilities, and directly from orders issued by state regulators. Explanatory footnotes are provided as necessary, and citations are given for orders published in *Public Utilities Reports, Fourth Series (PUR4th)*. Many of the unpublished orders are accessible through PURbase CD ROM, WESTLAW, and LEXIS.

A review of the rate orders included in the survey indicates that many state regulatory commissions continue to rely primarily on the results of discounted cash flow analyses in setting authorized ROE. However, other factors — e.g, general trends in interest rates, business risk, and regulatory risk — are often given considerable weight in ROE determinations.

Debate continues over the effect of electric industry restructuring and generation asset divestiture on risk, investor expectations, and required return. Similarly, regulators continue to consider whether the movement toward a competitive market model for the pricing of gas supply requires a reassessment of risks and required returns for natural gas local distribution companies. For example, in *Re Montana Power Co.*, 209 PUR4th 434 (Mont.P.S.C.2001), the state public service commission concluded that the electric util-

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EXHIBIT 13

EXHIBIT 14

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Public Utilities Reports Advance Sheets
December 15, 2001
by Public Service Commission
Exhibit # 13
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike

ity operations of Montana Power are less risky now that it has restructured and divested its generation assets. As a consequence, the commission reduced the equity ratio used in determining cost of capital for rate-making purposes from 44.12% common equity to 43%. In setting rates for the gas utility operations of Montana Power, the commission found that the gas utility faces less risk following the deregulation of natural gas supply and the implementation of a natural gas cost tracker that allows changes in commodity costs to be passed through to ratepayers without a full rate case. The authorized ROE for both the electric and gas utility was set at 10.75% — down from the 11% ROE last authorized for the electric utility and the 11.25% ROE awarded when rates were last set for the gas utility.

Although the number of "full-blown" rate cases appears to have diminished in recent years — the result of low inflation and the trend toward price regulation — the process of determining authorized ROE for energy utilities continues to dismay state regulators. The Oregon Public Utility Commission brought attention to this point while setting rates for Portland General Electric Company following an unprecedented rise in the cost of wholesale power. Noting that a large part of the rate hearing was devoted to argument over the proper ROE, the commission complained that given the inherent complexity of the issue it "may be impossible to devise a method to make the process of determining a reasonable ROE an agreeable one." Nevertheless, in an attempt to make the process less burdensome, the commission offered a generalized set of guidelines for witnesses to follow in presenting cost of capital recommendations in future rate cases. *Re Portland General Electric Co.*, UE 115, Order No. 01-777, 212 PUR4th 1 (Or.P.U.C.2001).

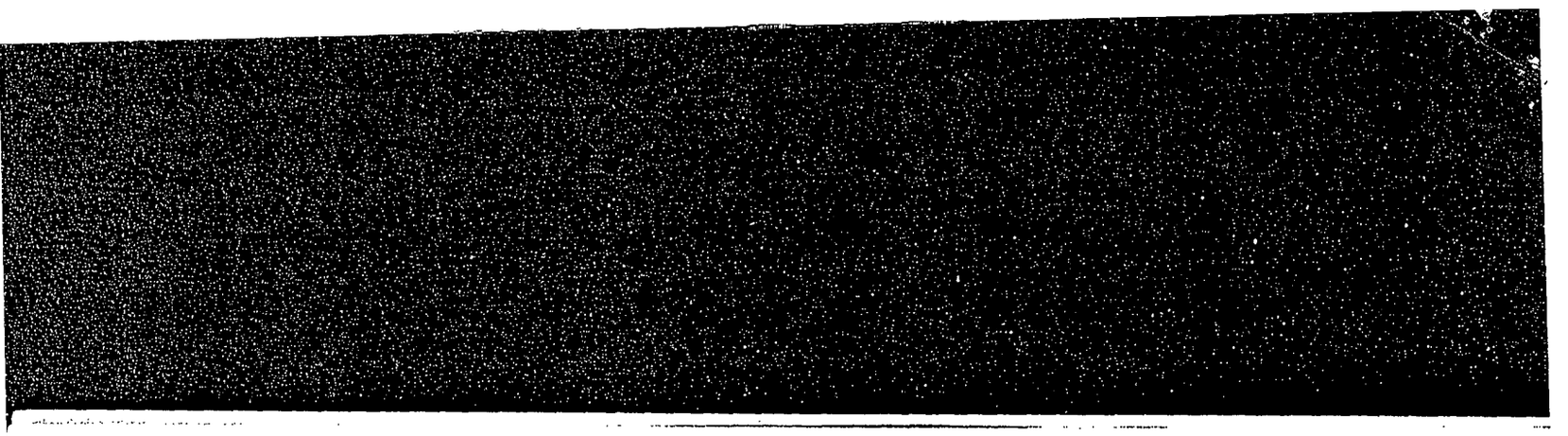
Compiled by Phillip S. Cross, a legal editor for Public Utilities Reports, Inc.

ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
ARIZONA									
Xcel Energy - Black Mountain Gas Co.	Gas	63545	4/28/00	3/30/01	12/31/99	0.326	0.174	—	10.75[1]
CALIFORNIA									
Sierra Pacific Power Co.	Electric	D.00-12-062 *206 PUR4th 248*	5/8/00	12/21/00	12/31/01	NA	[.562]	11.60	10.80[2]
COLORADO									
Public Service Co. of Colorado dba Xcel Energy	Gas	00S-422G C01-231 *208 PUR4th 322*	7/17/00	3/15/01	12/31/99	39.8	14.2	11.25	11.25
CONNECTICUT									
Connecticut Natural Gas Corp.	Gas	99-09-03 *210 PUR4th 27*	2/9/00	5/9/01	6/30/99	NA[3]	NA[4]	10.8	10.8[5]
Southern Connecticut Gas Co.	Gas	99-04-18	7/15/99	1/28/00	12/31/99	21.4	.502	11.45	10.71

[1]Derived from approved settlement agreement authorizing revenue increase shown.
[2]ROE for electric distribution operations. Commission establishes automatic trigger mechanism for adjusting ROE based on changes in interest rates.
[3]Utility proposed incentive rate plan designed to match costs and efficiencies of recent merger.
[4]Approved rate plan includes four-year rate freeze at levels approved in *Re Connecticut Natural Gas Co.*, 201 PUR4th 225 (Conn.D.P.U. 2000).
[5]Excess earnings sharing begins with allocation to ratepayers of 75% of first 200 basis points above 10.8% allowed ROE.



ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
FLORIDA									
Chesapeake Utilities Corp.	Gas	000108-GU	5/15/00	11/28/00	12/31/01	1.83	1.25	11.00	11.5
City Gas Co. of Florida	Gas	000768-GU *207 PUR4th 181*	8/25/00	2/5/01	9/30/01	7.18	5.13	11.3	11.5[6]
St. Joe Natural Gas Co.	Gas	001447-GU	12/15/00	6/8/01	12/31/01	.551	.327	11.0	11.5
HAWAII									
Hawaii Electric Light Co., Inc.	Electric	99-0207 Decision 18365 *207 PURth 117*	10/25/99	2/8/01	12/31/00	15.5	8.4	11.65	11.50[7]
IOWA									
United Cities Gas Co.	Gas	RPU-01-2	3/5/01	3/21/01	12/31/00	[.326]	[.326][8]	11.0	11.0

ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
KANSAS									
UtiliCorp, Inc.	Electric	01-WPEE-473-RTS	12/8/00	9/15/01	6/30/00	14.2	3.8	10.55	10.91
Western Resources, Inc. dba KPL	Electric	01-WSRE-436-RTS[9] *212 PUR4th 517*	11/27/00	9/5/01	9/30/00	92.6	25.4	*	11.02
Western Resources, Inc. dba Kansas Gas & Electric Co.	Electric	01-WSRE-436-RTS[9] *212 PUR4th 517*	11/27/00	9/5/01	9/30/00	57.9	[41.0]	*	11.02
KENTUCKY									
Louisville Gas & Electric Co.	Gas	2000-080 *204 PUR4th 196*	3/30/00	9/27/00	12/31/99	26.377	20.193	12.5	11.25[10]
LOUISIANA									
CLECO Corp.	Electric	U-21496D[11]	12/15/00	8/8/01	9/30/00	NA	NA	12.25	12.25
MINNESOTA									
UtiliCorp United, Inc. dba Peoples Natural Gas Co.	Gas	G-007 011/GRL 00-951	5/12/00	5/11/01	NA	8.461	4.802	NA	11.71[12]
UtiliCorp United, Inc. dba Northern Minnesota Utilities	Gas	G-007 011/GRL 00-951	5/12/00	5/11/01	NA	1.385	0.422	NA	11.71[12]

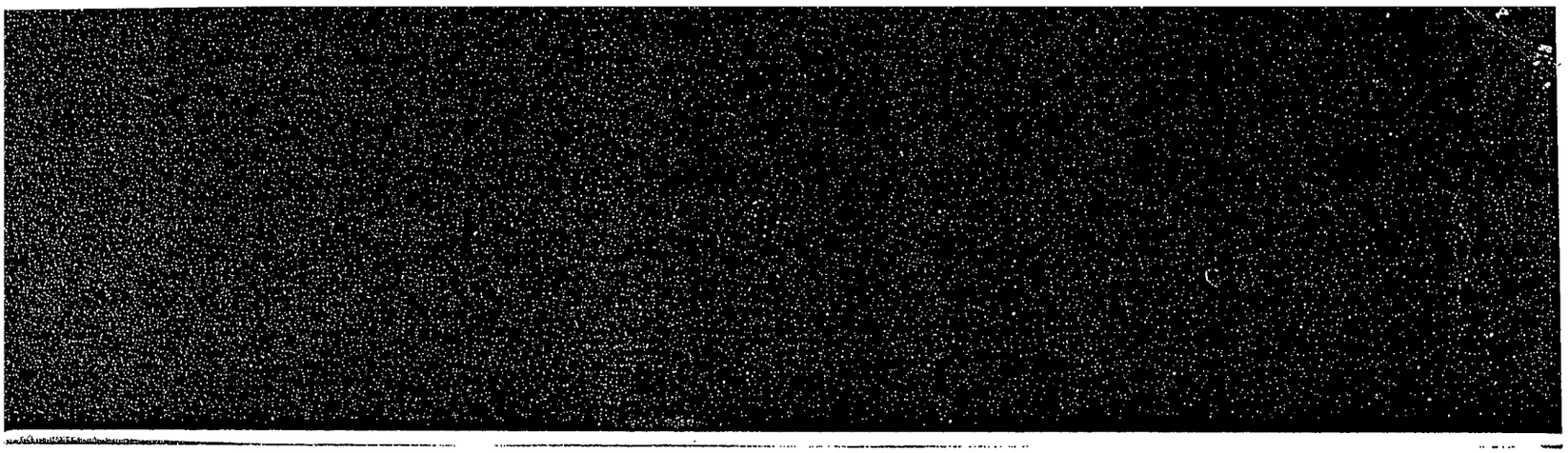
*Settlement, no authorized ROE specified.

[9]Order modifies and clarifies *Re Western Resources, Inc.*, 211 PUR4th 8, in which the commission set interim rates for two affiliated electric utilities. Rates to be made permanent once effect of recent corporate reorganization on capital structure is demonstrated. Commission rules that it may apply an "interest synchronization adjustment" if high debt level threatens financial stability of operating utilities.

[10]Return revenue requirement determined by applying cost of capital to gas capitalization, rather than to test period rate base. Commission finds that use of "inflated" rate base figures would produce inaccurate estimate of utility income requirements.

[11]Proceeding to review utility earnings.

[12]Figure shown is stated in approved modified settlement agreement.



ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
MISSISSIPPI									
Entergy Mississippi, Inc.	Electric	93-UA-301[13]	3/14/01	4/27/01	12/31/01	6.7	5.6	10.34	9.98
MONTANA									
Montana Power Co.	Electric	D.2000.8.113 *209 PUR4th 434*	8/11/00	5/9/01	12/31/99	38.5[14]	16.006[15]	11.0	10.75[16]
Montana Power Co.	Gas	D.2000.8.113 *209 PUR4th 434*	8/11/00	5/9/01	12/31/99	12.0[14]	4.268[15]	11.25	10.75[16]
NEW YORK									
Corning Natural Gas Corp.	Gas	00-G-0354	2/24/00	2/12/01	2/22/01[17]	.384	[.300]	NA	10.7
Niagara Mohawk Power Corp.	Gas	99-G-0336	3/11/99	7/27/00	10/31/00[17]	13.7	0	11.4	10.0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	NA	10.6[20]

ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
NORTH DAKOTA									
Northern States Power Co. dba Xcel Energy	Electric	PU-400-00-195	4/20/00	12/29/00	—	[0.3]	[0.3]	11.5	12.0[23]
Northern States Power Co. dba Xcel Energy	Gas	PU-400-00-521 211 PUR4th 44	10/9/00	6/27/01	12/31/00	1.4	0.5[24]	12.0	11.5
Otter Tail Power Co.	Electric	PU-401-00-36 *206 PUR4th 452*	1/31/00	12/29/00	1/1/01	—[25]	—[26]	NA	12.0[27]
Otter Tail Power Co.	Gas	PU-401-00-36 *206 PUR4th 452*	1/31/00	12/29/00	1/1/01	—[25]	—[26]	NA	12.0[27]
OREGON									
PacifiCorp	Electric	UE 111 Order No. 00-580	11/5/99	10/1/00	12/31/98	61.8	13.6	10.00	11.125[28]
PacifiCorp	Electric	UE 116 Order No. 01-787 *212 PUR4th 379*	11/1/00	9/7/01	12/31/01	160.8	64.4	11.125	10.75
Portland General Electric Co.	Electric	UE 115 Order No. 01-777 *212 PUR4th 1*	10/1/00	8/31/01	12/31/02	324.4	407.5[29]	11.60	10.50

[23]Rate application includes performance-based rate plan for five-year period 2001-2005. Allowed ROE varies around stated mid- point depending on performance results.

[24]Approved settlement agreement provides 1.2% increase in non- gas base rates. Test period cost of service reduced by $.125 million for savings resulting from merger of Northern States Power Co. and New Century Energies, Inc.

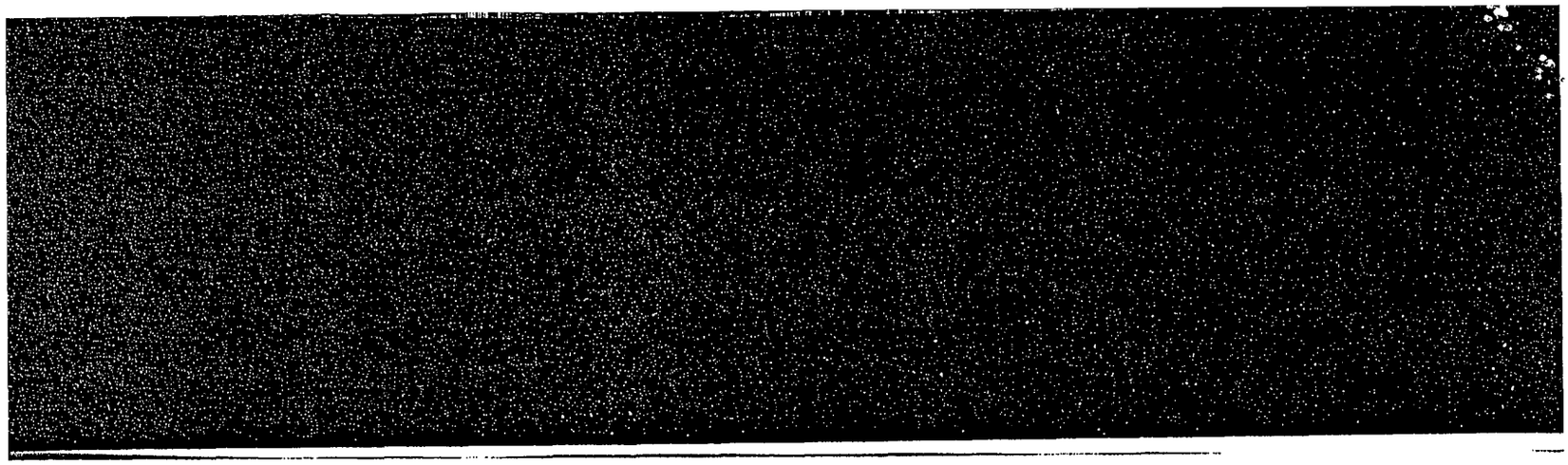
[25]Approved settlement initiates 5-year performance-based rate plan. Rates approved in 1999 earnings review case found just and reasonable as starting point for new rate plan.

[26]Performance-based rate plan includes price cap mechanism limiting rate adjustments based on comparable rates, inflation, and previous year earnings.

[27]Base line ROE for revenue sharing component of performance- based rate plan.

[28]Result of approved revenue stipulation.

[29]Increase reflects power costs updated subsequent to date of filing.



ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
RHODE ISLAND									
Providence Gas Co.	Gas	2581 Order No. 16584 *209 PURth 519*	8/2/00	4/30/01	10/1/00[30]	NA	4.5[31]	10.9	10.7[32]
TEXAS									
Entergy Gulf States, Inc.	Electric	22356	3/31/00	5/25/01	12/31/02	NA[33]	NA	10.95	11.25[34]
VERMONT									
Central Vermont Public Service Corp.	Electric	6460 *211 PUR4th 53*	11/9/00	6/26/01	6/30/00	19	9.852[35]	11.00	11.00

ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
VIRGINIA									
United Cities Gas Co.	Gas	PUE000171	3/24/00	5/22/01	12/31/99	2.051	[.534]	NA	11.0[37]
WASHINGTON									
Avista Corp.	Electric	UF-991606 *204 PUR4th 1*	10/22/99	9/29/00	12/31/98	26.25	[3.41]	12.9	11.16
Avista Corp.	Gas	UG-991607 *204 PUR4th 1*	10/22/99	9/29/00	12/31/98	4.9	1.67	10.75	11.16
Northwest Natural Gas Co.	Gas	UG-000073	1/21/00	10/26/00	12/31/99	6.2	4.3	11.25	10.8
WISCONSIN									
Madison Gas & Electric Co.	Electric	3270-UR-110	4/17/00	12/22/00	12/31/01	9.5	7.5	12.2	12.9
Madison Gas & Electric Co.	Gas	3270-UR-110	4/17/00	12/21/00	12/31/01	4.5	3.4	12.2	12.9
Midwest Natural Gas, Inc.	Gas	3670-GR-102	2/27/00	5/1/01	12/31/01	.6	.6	12.50	12.25
Northwestern Wisconsin Electric Co.	Electric	4280-ER-103	10/27/00	6/29/01	12/31/01	NA	.367	NA	12.75
Wisconsin Public Service Corp.	Electric	6690-UR-112 *206 PUR4th 1*	3/31/00	12/22/01	12/31/01	44.1[38]	27.1	12.1	12.1[39]
Wisconsin Public Service Corp.	Gas	6690-UR-112 *206 PUR4th 1*	3/31/00	12/22/01	12/31/01	4.9[38]	4.3	12.1	12.1[39]

[37]ROE figure stated in approved settlement agreement.

[38]Utility also requested $12.2 million electric and $3.7 million gas revenue increase to take effect beginning in 2002. No change for 2002 authorized by commission.

[39]Utility did not request a change in ROE in this docket.

Response of Charles W. King
To Montana-Dakota Utilities Co.
North Dakota Public Service Commission
Case No. PU-399-02-183
September 6, 2002 Data Request

14. Reference: Page 32, lines 17-19:
Describe the "observations" referred to by the testimony, including the observations of the return differences, and provide a copy of all source data for these various observations.

Response: The "observations" are the annualized returns to common stocks and to bonds. The attached tabulation of the Ibbotson data for equity and debt returns shows that the standard deviation for each series is substantially greater than the arithmetic mean, the geometric mean or the median. Any use of these mean or median numbers as a predictor of current equity risk premiums is therefore statistically invalid.

PENGAD 800-631-6989
EXHIBIT
12

Response of CW King Sept. 6 2002 Date Request
by Public Service Commission
Exhibit # 12
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2001

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.51%
1935	47.67%	78.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.28%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
Geometric Mean	10.37%	8.77%	5.72%	5.49%
Arithmetic Mean	12.33%	11.11%	6.06%	5.79%
Standard Deviation	20.30%	22.65%	8.76%	8.11%
Median	15.40%	11.26%	4.03%	4.55%

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the period from January 1, 2001 to December 31, 2001

Commission File Number 1-14161

KEYSPAN CORPORATION

(Exact name of registrant as specified in its charter)

NEW YORK	11-3431358
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)
One MetroTech Center, Brooklyn, New York	11201
175 East Old Country Road, Hicksville, New York	11801
(Address of principal executive offices)	(Zip code)

(718) 403-1000 (Brooklyn)
(516) 755-6650 (Hicksville)
(Registrant's telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, $.01 par value	New York Stock Exchange Pacific Stock Exchange
Series AA Preferred Stock, $25 par value	New York Stock Exchange Pacific Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

None
(Title of class)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes. _X_ No.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. __

As of March 1, 2002, the aggregate market value of the common stock held by non-affiliates (139,971,853 shares) of the registrant was $4,571,480,718.98 based on the closing price, on such date, of $32.66 per share.

As of March 1, 2002, there were 158,837,654 shares of common stock, $.01 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy Statement dated on or about March 22, 2002 is incorporated by reference into Part III hereof.

66 PU-399-02-183 Pages: 3

Securities and Exchange Com doc re
Keyspan Corp
by Public Service Commission
Exhibit # 11
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

EXHIBIT
11
PENGAD 800-631-6989

KEYSPAN CORPORATION
INDEX TO FORM 10-K

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Item 6. *Selected Financial Data*

(In Thousands of Dollars, Except Per Share Amounts)

	Year Ended December 31, 2001	Year Ended December 31, 2000	Year Ended December 31, 1999	Nine Months Ended December 31, 1998	Year Ended March 31, 1998
Income Summary					
Revenues					
Gas Distribution	**$3,613,551**	$2,555,785	$1,753,132	$856,172	$645,659
Electric Services	**1,421,079**	1,444,711	861,582	408,305	-
Electric Distribution	**-**	-	-	330,011	2,478,435
Gas Exploration and Production	**400,031**	274,209	150,581	70,812	-
Energy Services and Other	**1,198,454**	805,997	189,318	63,181	-
Total revenues	**6,633,115**	5,080,702	2,954,613	1,728,481	3,124,094
Operating expenses					
Purchased gas for resale	**2,171,113**	1,408,680	744,432	331,690	299,469
Fuel and purchased power	**538,532**	460,841	17,252	91,762	658,338
Operation and maintenance	**2,114,759**	1,659,736	1,091,166	777,678	511,165
Depreciation, depletion and amortization	**559,138**	330,922	253,440	254,859	183,129
Early retirement and severance charges	**-**	65,175	-	64,635	-
Operating taxes	**448,924**	421,936	366,154	257,124	466,326
Operating income	**800,649**	733,412	482,169	(49,267)	1,005,667
Other income (deductions)	**7,206**	(12,086)	46,555	(36,727)	(6,301)
Income (loss) before interest charges and income taxes	**807,855**	721,326	528,724	(85,994)	999,366
Interest charges	**353,470**	201,314	133,751	140,733	404,473
Income taxes (credits)	**210,693**	217,262	136,362	(59,794)	232,653
Net income (loss)	**243,692**	302,750	258,611	(166,933)	362,240
Preferred stock dividends	**5,904**	18,113	34,752	28,604	51,813
Earnings (loss) from Continuing Operations	**$237,788**	$284,637	$223,859	$(195,537)	$310,427
Discontinued Operations					
Income from operations, net of tax	**10,918**	(1,943)	-	-	-
Loss on disposal, net of tax	**(30,356)**	-	-	-	-
Earnings (loss) from Discontinued Operations	**(19,438)**	(1,943)	-	-	-
Earnings for Common Stock	**$218,350**	$282,694	$223,859	$(195,537)	$310,427
Financial Summary					
Basic earnings (loss) per share ($)	**1.58**	2.10	1.62	(1.34)	2.56
Cash dividends declared per share ($)	**1.78**	1.78	1.78	1.19	1.78
Book value per share, year-end ($)	**21.33**	20.65	20.26	20.90	21.88
Market value per share, year-end ($)	**34.65**	42.38	23.19	31.00	31.50
Shareholders	**82,300**	86,900	90,500	103,239	78,314
Capital expenditures ($)	**1,059,759**	925,257	725,670	676,563	297,230
Total assets ($)	**11,789,606**	11,307,465	6,730,691	6,895,102	11,900,725
Common equity ($)	**2,890,602**	2,815,816	2,712,325	3,022,908	2,662,447
Redeemable preferred stock ($)	**-**	-	363,000	-	562,600
Preferred stock ($)	**84,077**	84,205	84,339	447,973	-
Long term debt ($)	**4,697,649**	4,116,441	1,682,702	1,619,067	4,381,949
Total capitalization ($)	**7,672,328**	7,016,462	4,479,366	5,089,948	7,606,996
Utility Operating Statistics					
Firm gas and transportation sales (MDTH)	**427,051**	306,509	275,771	87,179	58,304
Other sales (MDTH)	**106,800**	91,406	54,661	38,088	21,025
Total active gas meters	**2,499,170**	2,483,730	1,628,497	1,610,202	464,563
Gas heating customers	**1,267,000**	1,260,000	677,000	665,000	295,000

Public Service Commission
State of North Dakota

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NORTH DAKOTA PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

EXHIBIT 10
PENGAD 800-631-6989

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

Memo

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

To: Commissioners, Illona & Bill

From: Mike Diller

Date: September 3, 2002

Re: 2001 Annual Reports

Following are the reported returns on equity earned by utilities operating in North Dakota.

Company	1998	1999	2000	2001	4-year Average
Great Plains Gas	3.31%	6.50%	8.85%	0.20%	4.72%
MDU Electric	14.37%	15.94%	17.95%	17.25%	16.38%
MDU Gas	14.55%	10.25%	11.92%	11.90%	12.16%
North Dakota Tel	10.85%	12.10%	11.36%	14.35%	12.17%
NSP Electric	11.50%	14.30%	11.15%	11.06%	12.00%
NSP Gas	6.12%	3.64%	3.61%	6.67%	5.01%
OTP Electric	10.18%	12.53%	12.91%	13.89%	12.38%
Qwest	17.82%	16.37%	16.87%	26.76%	19.46%
Average	10.13%	10.75%	11.11%	12.76%	11.78%

After reviewing the annual filings, I recommend that the commission close all 2001 annual reports without further investigations. I will briefly discuss why each report should be closed.

Staff has reviewed the earnings of Great Plains Natural Gas in recent years resulting in a rate decrease and rate moratorium. In addition, staff anticipates that Great Plains will be reporting significant losses during the next several years due to the amortization of the premium paid by MDU to acquire Great Plains. Due to the agreements reached in recent years and expected earnings levels in the near future, staff recommends that the commission close the 2001 annual report of Great Plains.

65 PU-399-02-183 Pages: 3
September 3, 2002 Mike Diller memo
by Public Service Commission
Exhibit # 10
10/07/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

The commission staff recently filed a complaint case against MDU's electric operations and proved its case before the commission. Therefore, there is little reason to pursue additional investigations in the immediate future. In addition, MDU has communicated to staff that regardless of the outcome of the off-system sales issue pending before the district court, MDU intends to file for a rate increase this fall in order to recover the costs of a new generator expected to come on-line before next summer.

MDU's gas operations have been earning reasonable returns on its equity invested in North Dakota with an average return of 12.16% over the past four years. However, a rate increase application has been filed by MDU alleging increased costs necessitating a 4.1% increase in rates. The commission will be making a determination in this case within the next couple of months and no further review or investigation is necessary regarding its 2001 annual report.

North Dakota Telephone has been reporting earnings in North Dakota averaging 12.17% in recent years. The earnings levels appear to be reasonable and no further investigation is warranted.

NSP's electric operations and Otter Tail Power are operating under a performance-based ratemaking plan for a five-year period ending December 31, 2005. The plans call for a review to be conducted after operating results are reported for the year ending 2002. Accordingly, the 2001 annual reports for both NSP electric and Otter Tail should be closed and a review conducted in 2002.

NSP's gas operations have averaged earnings of 5.01% during the past four years. As you may recall, NSP reported high earnings on its gas operations prior to the Flood in 1997. Since then, earnings have languished due to the rebuilding after the flood. In addition, NSP has gassed up some of the smaller communities around Fargo requiring a lot of capital expenditures. NSP is currently considering the need to file for a rate increase in 2002. Due to the earnings levels in recent years, NSP's 2001 annual report should be closed without further ado.

Qwest continues to make huge profits in North Dakota. In 2001, the company reported earnings on investment of 26.76% and an average return of 19.46% during the past 4 years. It is also worth noting that the Qwest numbers are a return on investment as compared to a return on equity reported by the other utilities. To show the impact of this difference,

if you assumed one-third of the investment in North Dakota was financed by an average debt cost of 8%, the average earnings on stockholder equity would be 25.19%. Said another way, Qwest would be recovering its stockholder investment in North Dakota approximately every 4 years. Qwest is not rate of return regulated but included here for comparative purposes. Because Qwest's rates are regulated through a price cap mechanism prescribed by law and not rate of return regulated, staff recommends that Qwest's annual report be closed without further review.

I will provide copies of this memo to each of the regulated entities referenced in this report so that they can file comments should they choose to do so.

This memo has been docketed in case management, as follows:

Great Plains	PU-402-02-193
MDU Electric	PU-399-02-197
MDU Gas	PU-399-02-196
N.D. Tel	PU-1264-02-137
NSP Electric	PU-400-02-234
NSP Gas	PU-400-02-235
Otter Tail	PU-401-02-221
Qwest	PU-2342-02-200

C: Jeffrey Johnson, Great Plains
Don Ball, MDU
Shawna Senger, North Dakota Telephone
Dave Sederquist, NSP
Bernadeen Brutlag, Otter Tail
Scott Macintosh, Qwest

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

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ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

October 23, 2002

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Case No. PU-399-02-183

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of the Late Filed Exhibits 1 through 6 requested at the hearing held on October 7 and 8, 2002, in the above referenced case.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,

Donald R. Ball
Director of Regulatory Affairs

cc: D. Schulz
W. Pearce

64 PU-399-02-183 Pages: 69

Late Filed Exhibits 1 through 6 from
Hearing held October 7-8, 2002
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 1-6
10/23/2002 CC: Comm Legal Illona, Pat, Jerry Mike

MONTANA-DAKOTA UTILITIES CO.
LATE FILED EXHIBITS
CASE NO. PU-399-02-183

Late Filed Exhibit 1

Provide the retirements related to the $1.4 million net negative salvage for services (Acct. 380) recorded in the period 1996 through 2001.

Response:

Please see Attachment A for the number of services, the original cost of plant, the removal cost, the accumulated depreciation and net over(under) recovery on services. The schedule shows vintage years and indicates that removal costs for the 6 year period averaged 138 percent of the original cost and that the accumulated depreciation fell far short of recovering the total cost.

Case No. PU-399-02-183
Late Filed Exhibit 1
Attachment A

ATTACHMENT A

Montana-Dakota Utilities Co.
Gas Services - Subplant Account 380
Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1926	1996	-3	99.30	0.00	99.30	275.96 %	274.03	174.73	175.96%
1926	1997	-1	33.10	76.84	109.94	284.18 %	94.06	(15.88)	-47.98%
1926	1998	0	0.00	0.00	0.00	292.40 %	0.00	-	
1926	1999	0	0.00	0.00	0.00	300.62 %	0.00	-	
1926	2000	0	0.00	0.00	0.00	308.84 %	0.00	-	
1926	2001	0	0.00	0.00	0.00	317.06 %	0.00	-	
		-4	**132.40**	**76.84**	**209.24**		**368.09**	**158.85**	**119.98%**
1927	1996	-4	132.40	0.00	132.40	272.96 %	361.40	229.00	172.96%
1927	1997	0	0.00	0.00	0.00	281.18 %	0.00	-	
1927	1998	0	0.00	255.46	255.46	289.40 %	0.00	(255.46)	
1927	1999	0	0.00	0.00	0.00	297.62 %	0.00	-	
1927	2000	0	0.00	0.00	0.00	305.84 %	0.00	-	
1927	2001	0	0.00	0.00	0.00	314.06 %	0.00	-	
		-4	**132.40**	**255.46**	**387.86**		**361.40**	**(26.46)**	**-19.98%**
1928	1996	-3	94.10	75.25	169.35	269.96 %	254.03	84.68	89.99%
1928	1997	-2	55.80	0.00	55.80	278.18 %	155.22	99.42	178.17%
1928	1998	0	0.00	0.00	0.00	286.40 %	0.00	-	
1928	1999	0	0.00	0.00	0.00	294.62 %	0.00	-	
1928	2000	-1	33.10	333.64	366.74	302.84 %	100.24	(266.50)	-805.14%
1928	2001	0	0.00	0.00	0.00	311.06 %	0.00	-	
		-6	**183.00**	**408.89**	**591.89**		**509.49**	**(82.40)**	**-45.03%**
1929	1996	-4	120.65	432.39	553.04	266.96 %	322.09	(230.95)	-191.42%
1929	1997	0	0.00	0.00	0.00	275.18 %	0.00	-	
1929	1998	-1	33.10	0.00	33.10	283.40 %	93.81	60.71	183.41%
1929	1999	0	0.00	0.00	0.00	291.62 %	0.00	-	
1929	2000	0	0.00	0.00	0.00	299.84 %	0.00	-	
1929	2001	0	0.00	0.00	0.00	308.06 %	0.00	-	
		-5	**153.75**	**432.39**	**586.14**		**415.90**	**(170.24)**	**-110.73%**
1930	1995	-2	66.20	159.25	225.45	255.74 %	169.30	(56.15)	-84.82%
1930	1996	-27	1068.30	0.00	1068.30	263.96 %	2819.88	1,751.58	163.96%
1930	1997	-4	127.20	549.15	676.35	272.18 %	346.21	(330.14)	-259.54%
1930	1998	-4	132.40	701.71	834.11	280.40 %	371.25	(462.86)	-349.59%
1930	1999	-1	27.90	0.00	27.90	288.62 %	80.52	52.62	188.60%
1930	2000	-2	61.00	622.31	683.31	296.84 %	181.07	(502.24)	-823.34%
1930	2001	-3	99.30	878.78	978.08	305.06 %	302.92	(675.16)	-679.92%

Montana-Dakota Utilities Co.
Gas Services - Subplant Account 380
Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
		-43	**1582.30**	**2911.20**	**4493.50**		**4271.15**	**(222.35)**	**-14.05%**
1931	1996	-8	259.60	49.08	308.68	260.96 %	677.45	368.77	142.05%
1931	1997	0	0.00	0.00	0.00	269.18 %	0.00	-	
1931	1998	-1	33.10	251.31	284.41	277.40 %	91.82	(192.59)	-581.84%
1931	1999	-6	167.40	0.00	167.40	285.62 %	478.13	310.73	185.62%
1931	2000	0	0.00	0.00	0.00	293.84 %	0.00	-	
1931	2001	0	0.00	0.00	0.00	302.06 %	0.00	-	
		-15	**460.10**	**300.39**	**760.49**		**1247.40**	**486.91**	**105.83%**
1932	1996	-16	519.20	258.75	777.95	257.96 %	1339.33	561.38	108.12%
1932	1997	-3	82.35	595.44	677.79	266.18 %	219.20	(458.59)	-556.88%
1932	1998	-2	61.00	753.86	814.86	274.40 %	167.38	(647.48)	-1061.44%
1932	1999	-3	83.70	0.00	83.70	282.62 %	236.55	152.85	182.62%
1932	2000	-1	33.10	181.18	214.28	290.84 %	96.27	(118.01)	-356.53%
1932	2001	-2	61.00	117.90	178.90	299.06 %	182.43	3.53	5.79%
		-27	**840.35**	**1907.13**	**2747.48**		**2241.16**	**(506.32)**	**-60.25%**
1933	1996	-3	94.10	49.08	143.18	254.96 %	239.92	96.74	102.81%
1933	1997	0	0.00	0.00	0.00	263.18 %	0.00	-	
1933	1998	0	0.00	0.00	0.00	271.40 %	0.00	-	
1933	1999	-5	144.70	276.49	421.19	279.62 %	404.61	(16.58)	-11.46%
1933	2000	0	0.00	0.00	0.00	287.84 %	0.00	-	
1933	2001	-3	88.90	145.95	234.85	296.06 %	263.20	28.35	31.89%
		-11	**327.70**	**471.52**	**799.22**		**907.73**	**108.51**	**33.11%**
1934	1995	-2	66.20	180.57	246.77	243.74 %	161.36	(85.41)	-129.02%
1934	1996	-2	61.00	49.08	110.08	251.96 %	153.70	43.62	71.51%
1934	1997	-2	66.20	511.85	578.05	260.18 %	172.24	(405.81)	-613.01%
1934	1998	-3	88.90	1004.52	1093.42	268.40 %	238.61	(854.81)	-961.54%
1934	1999	-9	251.10	440.38	691.48	276.62 %	694.59	3.11	1.24%
1934	2000	-1	33.10	306.44	339.54	284.84 %	94.28	(245.26)	-740.97%
1934	2001	0	0.00	0.00	0.00	293.06 %	0.00	-	
		-19	**566.50**	**2492.84**	**3059.34**		**1514.78**	**(1,544.56)**	**-272.65%**
1935	1995	-7	219.95	943.87	1163.82	240.74 %	529.51	(634.31)	-288.39%
1935	1996	-20	656.80	1070.00	1726.80	248.96 %	1635.17	(91.63)	-13.95%
1935	1997	-8	254.40	829.11	1083.51	257.18 %	654.27	(429.24)	-168.73%
1935	1998	-12	439.80	2447.36	2887.16	265.40 %	1167.23	(1,719.93)	-391.07%
1935	1999	-14	447.80	2279.34	2727.14	273.62 %	1225.27	(1,501.87)	-335.39%

Montana-Dakota Utilities Co.
Gas Services - Subplant Account 380
Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1935	2000	-49	1634.20	8497.16	10131.36	281.84 %	4605.83	(5,525.53)	-338.12%
1935	2001	-14	459.05	2074.30	2533.35	290.06 %	1331.52	(1,201.83)	-261.81%
		-124	**4112.00**	**18141.14**	**22253.14**		**11148.80**	**(11,104.34)**	**-270.05%**
1936	1995	-1	27.90	10.02	37.92	237.74 %	66.33	28.41	101.83%
1936	1996	-11	358.90	66.70	425.60	245.96 %	882.75	457.15	127.38%
1936	1997	-3	94.10	438.59	532.69	254.18 %	239.18	(293.51)	-311.91%
1936	1998	0	0.00	0.00	0.00	262.40 %	0.00	-	
1936	1999	-17	467.75	216.84	684.59	270.62 %	1265.83	581.24	124.26%
1936	2000	-5	139.50	289.63	429.13	278.84 %	388.98	(40.15)	-28.78%
1936	2001	0	0.00	0.00	0.00	287.06 %	0.00	-	
		-37	**1088.15**	**1021.78**	**2109.93**		**2843.07**	**733.14**	**67.37%**
1937	1995	-7	219.85	832.78	1052.63	234.74 %	516.08	(536.55)	-244.05%
1937	1996	-12	381.60	720.43	1102.03	242.96 %	927.14	(174.89)	-45.83%
1937	1997	-2	66.20	77.61	143.81	251.18 %	166.28	22.47	33.94%
1937	1998	-1	21.35	176.91	198.26	259.40 %	55.38	(142.88)	-669.23%
1937	1999	-14	377.50	683.83	1061.33	267.62 %	1010.27	(51.06)	-13.53%
1937	2000	-13	362.70	119.03	481.73	275.84 %	1000.47	518.74	143.02%
1937	2001	-3	82.20	1377.11	1459.31	284.06 %	233.50	(1,225.81)	-1491.25%
		-52	**1511.40**	**3987.70**	**5499.10**		**3909.12**	**(1,589.98)**	**-105.20%**
1938	1995	-4	132.40	486.28	618.68	231.74 %	306.82	(311.86)	-235.54%
1938	1996	-21	663.90	733.75	1397.65	239.96 %	1593.09	195.44	29.44%
1938	1997	-6	176.45	784.71	961.16	248.18 %	437.91	(523.25)	-296.54%
1938	1998	-3	99.30	538.83	638.13	256.40 %	254.61	(383.52)	-386.22%
1938	1999	-27	768.90	511.16	1280.06	264.62 %	2034.66	754.60	98.14%
1938	2000	-32	908.40	552.35	1460.75	272.84 %	2478.48	1,017.73	112.04%
1938	2001	-1	33.10	185.34	218.44	281.06 %	93.03	(125.41)	-378.88%
		-94	**2782.45**	**3792.42**	**6574.87**		**7198.60**	**623.73**	**22.42%**
1939	1995	-1	27.90	252.95	280.85	228.74 %	63.82	(217.03)	-777.89%
1939	1996	-26	787.80	867.38	1655.18	236.96 %	1866.77	211.59	26.86%
1939	1997	-5	143.35	1405.95	1549.30	245.18 %	351.47	(1,197.83)	-835.60%
1939	1998	-19	517.00	4068.31	4585.31	253.40 %	1310.08	(3,275.23)	-633.51%
1939	1999	-73	2050.95	905.99	2956.94	261.62 %	5365.70	2,408.76	117.45%
1939	2000	-80	2232.00	944.98	3176.98	269.84 %	6022.83	2,845.85	127.50%
1939	2001	-6	177.80	1172.16	1349.96	278.06 %	494.39	(855.57)	-481.20%
		-210	**5936.80**	**9617.72**	**15554.52**		**15475.06**	**(79.46)**	**-1.34%**

Montana-Dakota Utilities Co.
Gas Services - Subplant Account 380
Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1940	1995	-3	70.60	450.02	520.62	225.74 %	159.37	(361.25)	-511.69%
1940	1996	-38	1119.80	1556.67	2676.47	233.96 %	2619.88	(56.59)	-5.05%
1940	1997	-5	168.07	1193.04	1361.11	242.18 %	407.03	(954.08)	-567.67%
1940	1998	-16	450.25	1428.50	1878.75	250.40 %	1127.43	(751.32)	-166.87%
1940	1999	-55	1535.65	2171.09	3706.74	258.62 %	3971.50	264.76	17.24%
1940	2000	-27	767.45	1072.62	1840.07	266.84 %	2047.86	207.79	27.08%
1940	2001	-4	125.75	624.86	750.61	275.06 %	345.89	(404.72)	-321.84%
		-148	**4237.57**	**8496.80**	**12734.37**		**10678.96**	**(2,055.41)**	**-48.50%**
1941	1995	-5	123.45	1102.38	1225.83	222.74 %	274.97	(950.86)	-770.24%
1941	1996	-28	832.45	1846.80	2679.25	230.96 %	1922.63	(756.62)	-90.89%
1941	1997	-4	145.02	789.55	934.57	239.18 %	346.86	(587.71)	-405.26%
1941	1998	-1	27.90	282.48	310.38	247.40 %	69.02	(241.36)	-865.09%
1941	1999	-32	892.80	503.74	1396.54	255.62 %	2282.18	885.64	99.20%
1941	2000	-28	781.20	0.00	781.20	263.84 %	2061.12	1,279.92	163.84%
1941	2001	-7	200.50	1016.63	1217.13	272.06 %	545.48	(671.65)	-334.99%
		-105	**3003.32**	**5541.58**	**8544.90**		**7502.26**	**(1,042.64)**	**-34.72%**
1942	1995	-1	31.65	144.66	176.31	219.74 %	69.55	(106.76)	-337.31%
1942	1996	-28	784.90	1462.75	2247.65	227.96 %	1789.26	(458.39)	-58.40%
1942	1997	-1	33.10	95.23	128.33	236.18 %	78.18	(50.15)	-151.51%
1942	1998	-1	33.10	245.66	278.76	244.40 %	80.90	(197.86)	-597.76%
1942	1999	-8	216.65	320.05	536.70	252.62 %	547.30	10.60	4.89%
1942	2000	-7	204.25	737.03	941.28	260.84 %	532.77	(408.51)	-200.00%
1942	2001	-2	61.00	1043.29	1104.29	269.06 %	164.13	(940.16)	-1541.25%
		-48	**1364.65**	**4048.67**	**5413.32**		**3262.09**	**(2,151.23)**	**-157.64%**
1943	1995	-1	33.10	402.47	435.57	216.74 %	71.74	(363.83)	-1099.18%
1943	1996	-5	145.50	774.48	919.98	224.96 %	327.32	(592.66)	-407.33%
1943	1997	0	0.00	0.00	0.00	233.18 %	0.00	-	
1943	1998	0	0.00	0.00	0.00	241.40 %	0.00	-	
1943	1999	-2	55.80	0.00	55.80	249.62 %	139.29	83.49	149.62%
1943	2000	0	0.00	0.00	0.00	257.84 %	0.00	-	
1943	2001	-2	49.10	333.82	382.92	266.06 %	130.64	(252.28)	-513.81%
		-10	**283.50**	**1510.77**	**1794.27**		**668.99**	**(1,125.28)**	**-396.92%**
1944	1995	-8	181.10	1411.45	1592.55	213.74 %	387.08	(1,205.47)	-665.64%
1944	1996	-5	150.85	504.14	654.99	221.96 %	334.83	(320.16)	-212.24%
1944	1997	-1	33.10	243.94	277.04	230.18 %	76.19	(200.85)	-606.80%

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Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1944	1998	-2	61.00	213.70	274.70	238.40 %	145.42	(129.28)	-211.93%
1944	1999	-2	55.80	0.00	55.80	246.62 %	137.61	81.81	146.61%
1944	2000	-4	104.90	475.88	580.78	254.84 %	267.33	(313.45)	-298.81%
1944	2001	0	0.00	0.00	0.00	263.06 %	0.00	-	
		-22	**586.75**	**2849.11**	**3435.86**		**1348.46**	**(2,087.40)**	**-355.76%**
1945	1995	-13	375.85	1035.09	1410.94	210.74 %	792.07	(618.87)	-164.66%
1945	1996	-19	555.35	1766.67	2322.02	218.96 %	1215.99	(1,106.03)	-199.16%
1945	1997	-7	183.15	1995.61	2178.76	227.18 %	416.08	(1,762.68)	-962.42%
1945	1998	-8	216.65	1051.71	1268.36	235.40 %	509.99	(758.37)	-350.04%
1945	1999	-21	614.75	923.40	1538.15	243.62 %	1497.65	(40.50)	-6.59%
1945	2000	-10	287.10	1780.68	2067.78	251.84 %	723.03	(1,344.75)	-468.39%
1945	2001	-8	225.40	2231.39	2456.79	260.06 %	586.18	(1,870.61)	-829.91%
		-86	**2458.25**	**10784.55**	**13242.80**		**5740.99**	**(7,501.81)**	**-305.17%**
1946	1995	-4	107.45	572.21	679.66	207.74 %	223.22	(456.44)	-424.79%
1946	1996	-35	1018.35	3230.07	4248.42	215.96 %	2199.23	(2,049.19)	-201.23%
1946	1997	-8	233.60	2632.68	2866.28	224.18 %	523.68	(2,342.60)	-1002.83%
1946	1998	-12	330.65	3345.27	3675.92	232.40 %	768.43	(2,907.49)	-879.33%
1946	1999	-69	1916.90	1067.56	2984.46	240.62 %	4612.44	1,627.98	84.93%
1946	2000	-12	321.40	1206.43	1527.83	248.84 %	799.77	(728.06)	-226.53%
1946	2001	-14	367.55	1002.02	1369.57	257.06 %	944.82	(424.75)	-115.56%
		-154	**4295.90**	**13056.24**	**17352.14**		**10071.59**	**(7,280.55)**	**-169.48%**
1947	1995	-10	275.30	456.72	732.02	204.74 %	563.65	(168.37)	-61.16%
1947	1996	-37	1067.20	1770.36	2837.56	212.96 %	2272.71	(564.85)	-52.93%
1947	1997	-15	401.25	1598.90	2000.15	221.18 %	887.48	(1,112.67)	-277.30%
1947	1998	-6	172.60	2125.21	2297.81	229.40 %	395.94	(1,901.87)	-1101.89%
1947	1999	-47	1316.50	1976.74	3293.24	237.62 %	3128.27	(164.97)	-12.53%
1947	2000	-9	256.30	581.66	837.96	245.84 %	630.09	(207.87)	-81.10%
1947	2001	-12	340.00	1936.80	2276.80	254.06 %	863.80	(1,413.00)	-415.59%
		-136	**3829.15**	**10446.39**	**14275.54**		**8741.94**	**(5,533.60)**	**-144.51%**
1948	1995	-19	599.02	636.19	1235.21	201.74 %	1208.46	(26.75)	-4.47%
1948	1996	-83	2465.20	4199.20	6664.40	209.96 %	5175.93	(1,488.47)	-60.38%
1948	1997	-17	579.45	1996.33	2575.78	218.18 %	1264.24	(1,311.54)	-226.34%
1948	1998	-4	142.16	702.34	844.50	226.40 %	321.85	(522.65)	-367.65%
1948	1999	-36	1008.65	2571.92	3580.57	234.62 %	2366.49	(1,214.08)	-120.37%
1948	2000	-23	621.75	1070.93	1692.68	242.84 %	1509.86	(182.82)	-29.40%

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Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1948	2001	-22	621.60	1220.40	1842.00	251.06 %	1560.59	(281.41)	-45.27%
		-204	**6037.83**	**12397.31**	**18435.14**		**13407.42**	**(5,027.72)**	**-83.27%**
1949	1995	-19	583.55	1312.31	1895.86	198.74 %	1159.75	(736.11)	-126.14%
1949	1996	-78	2324.40	3598.78	5923.18	206.96 %	4810.58	(1,112.60)	-47.87%
1949	1997	-30	823.15	1430.30	2253.45	215.18 %	1771.25	(482.20)	-58.58%
1949	1998	-11	258.60	1943.24	2201.84	223.40 %	577.71	(1,624.13)	-628.05%
1949	1999	-23	625.80	1497.80	2123.60	231.62 %	1449.48	(674.12)	-107.72%
1949	2000	-8	209.12	1516.77	1725.89	239.84 %	501.55	(1,224.34)	-585.47%
1949	2001	-6	244.85	755.19	1000.04	248.06 %	607.37	(392.67)	-160.37%
		-175	**5069.47**	**12054.39**	**17123.86**		**10877.69**	**(6,246.17)**	**-123.21%**
1950	1995	-39	1265.54	3822.06	5087.60	195.74 %	2477.17	(2,610.43)	-206.27%
1950	1996	-101	3123.15	5417.43	8540.58	203.96 %	6369.98	(2,170.60)	-69.50%
1950	1997	-34	985.20	3946.18	4931.38	212.18 %	2090.40	(2,840.98)	-288.37%
1950	1998	-27	1231.85	4776.93	6008.78	220.40 %	2715.00	(3,293.78)	-267.38%
1950	1999	-33	990.45	2775.10	3765.55	228.62 %	2264.37	(1,501.18)	-151.57%
1950	2000	-39	1422.08	7540.93	8963.01	236.84 %	3368.05	(5,594.96)	-393.43%
1950	2001	-25	777.48	2871.81	3649.29	245.06 %	1905.29	(1,744.00)	-224.31%
		-298	**9795.75**	**31150.44**	**40946.19**		**21190.26**	**(19,755.93)**	**-201.68%**
1951	1995	-23	653.55	1855.34	2508.89	192.74 %	1259.65	(1,249.24)	-191.15%
1951	1996	-54	1577.95	4748.90	6326.85	200.96 %	3171.05	(3,155.80)	-199.99%
1951	1997	-10	293.45	575.66	869.11	209.18 %	613.84	(255.27)	-86.99%
1951	1998	-19	595.55	1895.27	2490.82	217.40 %	1294.73	(1,196.09)	-200.84%
1951	1999	-33	981.65	4732.66	5714.31	225.62 %	2214.80	(3,499.51)	-356.49%
1951	2000	-15	496.05	2302.46	2798.51	233.84 %	1159.96	(1,638.55)	-330.32%
1951	2001	-15	462.40	2427.11	2889.51	242.06 %	1119.29	(1,770.22)	-382.83%
		-169	**5060.60**	**18537.40**	**23598.00**		**10833.32**	**(12,764.68)**	**-252.24%**
1952	1995	-42	1378.55	5903.38	7281.93	189.74 %	2615.66	(4,666.27)	-338.49%
1952	1996	-63	1898.45	5880.51	7778.96	197.96 %	3758.17	(4,020.79)	-211.79%
1952	1997	-18	555.87	2546.48	3102.35	206.18 %	1146.09	(1,956.26)	-351.93%
1952	1998	-34	1214.58	6152.61	7367.19	214.40 %	2604.06	(4,763.13)	-392.16%
1952	1999	-34	1036.35	6558.27	7594.62	222.62 %	2307.12	(5,287.50)	-510.20%
1952	2000	-25	751.30	4143.09	4894.39	230.84 %	1734.30	(3,160.09)	-420.62%
1952	2001	-33	941.05	5633.77	6574.82	239.06 %	2249.67	(4,325.15)	-459.61%
		-249	**7776.15**	**36818.11**	**44594.26**		**16415.07**	**(28,179.19)**	**-362.38%**
1953	1995	-33	973.40	4423.43	5396.83	186.74 %	1817.73	(3,579.10)	-367.69%

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Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1953	1996	-43	1203.10	5886.58	7089.68	194.96 %	2345.56	(4,744.12)	-394.32%
1953	1997	-42	1321.45	7492.30	8813.75	203.18 %	2684.92	(6,128.83)	-463.80%
1953	1998	-35	1063.58	5294.96	6358.54	211.40 %	2248.41	(4,110.13)	-386.44%
1953	1999	-36	1150.49	6917.44	8067.93	219.62 %	2526.71	(5,541.22)	-481.64%
1953	2000	-83	2419.45	8679.13	11098.58	227.84 %	5512.47	(5,586.11)	-230.88%
1953	2001	-42	1164.25	7811.57	8975.82	236.06 %	2748.33	(6,227.49)	-534.89%
		-314	**9295.72**	**46505.41**	**55801.13**		**19884.13**	**(35,917.00)**	**-386.38%**
1954	1995	-27	878.51	3568.09	4446.60	183.74 %	1614.17	(2,832.43)	-322.41%
1954	1996	-75	2235.19	8482.54	10717.73	191.96 %	4290.67	(6,427.06)	-287.54%
1954	1997	-56	1975.95	7806.75	9782.70	200.18 %	3955.46	(5,827.24)	-294.91%
1954	1998	-41	1426.65	8831.77	10258.42	208.40 %	2973.14	(7,285.28)	-510.66%
1954	1999	-52	1426.90	7647.37	9074.27	216.62 %	3090.95	(5,983.32)	-419.32%
1954	2000	-52	1548.51	9264.95	10813.46	224.84 %	3481.67	(7,331.79)	-473.47%
1954	2001	-51	1806.31	8765.21	10571.52	233.06 %	4209.79	(6,361.73)	-352.19%
		-354	**11298.02**	**54366.68**	**65664.70**		**23615.85**	**(42,048.85)**	**-372.18%**
1955	1995	-45	1446.84	6724.96	8171.80	180.74 %	2615.02	(5,556.78)	-384.06%
1955	1996	-66	1944.85	7899.89	9844.74	188.96 %	3674.99	(6,169.75)	-317.24%
1955	1997	-76	2251.49	6132.10	8383.59	197.18 %	4439.49	(3,944.10)	-175.18%
1955	1998	-34	995.68	6373.84	7369.52	205.40 %	2045.13	(5,324.39)	-534.75%
1955	1999	-28	849.75	3999.98	4849.73	213.62 %	1815.24	(3,034.49)	-357.10%
1955	2000	-20	595.50	4212.23	4807.73	221.84 %	1321.06	(3,486.67)	-585.50%
1955	2001	-20	614.65	3247.25	3861.90	230.06 %	1414.06	(2,447.84)	-398.25%
		-289	**8698.76**	**38590.25**	**47289.01**		**17324.99**	**(29,964.02)**	**-344.46%**
1956	1995	-41	1254.10	7274.93	8529.03	177.74 %	2229.04	(6,299.99)	-502.35%
1956	1996	-79	2595.06	10116.25	12711.31	185.96 %	4825.77	(7,885.54)	-303.87%
1956	1997	-41	1180.50	6440.51	7621.01	194.18 %	2292.29	(5,328.72)	-451.40%
1956	1998	-41	1365.24	7841.16	9206.40	202.40 %	2763.25	(6,443.15)	-471.94%
1956	1999	-43	1433.60	6893.15	8326.75	210.62 %	3019.45	(5,307.30)	-370.21%
1956	2000	-43	1274.65	7192.99	8467.64	218.84 %	2789.44	(5,678.20)	-445.47%
1956	2001	-52	1892.34	11645.74	13538.08	227.06 %	4296.75	(9,241.33)	-488.35%
		-340	**10995.49**	**57404.73**	**68400.22**		**22215.99**	**(46,184.23)**	**-420.03%**
1957	1995	-21	652.06	3556.78	4208.84	174.74 %	1139.41	(3,069.43)	-470.73%
1957	1996	-55	1766.50	8015.39	9781.89	182.96 %	3231.99	(6,549.90)	-370.78%
1957	1997	-81	2704.24	6244.80	8949.04	191.18 %	5169.97	(3,779.07)	-139.75%
1957	1998	-35	1137.42	7658.14	8795.56	199.40 %	2268.02	(6,527.54)	-573.89%

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Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1957	1999	-15	414.00	2403.11	2817.11	207.62 %	859.55	(1,957.56)	-472.84%
1957	2000	-31	923.22	4805.56	5728.78	215.84 %	1992.68	(3,736.10)	-404.68%
1957	2001	-24	722.59	4630.60	5353.19	224.06 %	1619.04	(3,734.15)	-516.77%
		-262	**8320.03**	**37314.38**	**45634.41**		**16280.66**	**(29,353.75)**	**-352.81%**
1958	1995	-19	598.76	2827.80	3426.56	171.74 %	1028.31	(2,398.25)	-400.54%
1958	1996	-23	708.45	3287.76	3996.21	179.96 %	1274.93	(2,721.28)	-384.12%
1958	1997	-37	1073.45	4802.22	5875.67	188.18 %	2020.02	(3,855.65)	-359.18%
1958	1998	-25	958.58	4605.93	5564.51	196.40 %	1882.65	(3,681.86)	-384.10%
1958	1999	-21	681.00	5020.68	5701.68	204.62 %	1393.46	(4,308.22)	-632.63%
1958	2000	-25	777.02	3640.16	4417.18	212.84 %	1653.81	(2,763.37)	-355.64%
1958	2001	-23	608.75	3872.96	4481.71	221.06 %	1345.70	(3,136.01)	-515.16%
		-173	**5406.01**	**28057.51**	**33463.52**		**10598.88**	**(22,864.64)**	**-422.95%**
1959	1995	-14	428.75	1516.23	1944.98	168.74 %	723.47	(1,221.51)	-284.90%
1959	1996	-30	966.50	3397.19	4363.69	176.96 %	1710.32	(2,653.37)	-274.53%
1959	1997	-61	1799.35	4131.25	5930.60	185.18 %	3332.04	(2,598.56)	-144.42%
1959	1998	-40	1315.28	7841.39	9156.67	193.40 %	2543.75	(6,612.92)	-502.78%
1959	1999	-29	901.25	4825.19	5726.44	201.62 %	1817.10	(3,909.34)	-433.77%
1959	2000	-46	1360.29	7970.14	9330.43	209.84 %	2854.43	(6,476.00)	-476.07%
1959	2001	-40	1194.80	5957.42	7152.22	218.06 %	2605.38	(4,546.84)	-380.55%
		-260	**7966.22**	**35638.81**	**43605.03**		**15586.49**	**(28,018.54)**	**-351.72%**
1960	1995	-15	438.45	19556.62	19995.07	165.74 %	726.69	(19,268.38)	-4394.66%
1960	1996	-265	7821.04	6444.74	14265.78	173.96 %	13605.48	(660.30)	-8.44%
1960	1997	-43	1241.20	6392.57	7633.77	182.18 %	2261.22	(5,372.55)	-432.85%
1960	1998	-173	5529.28	13412.19	18941.47	190.40 %	10527.75	(8,413.72)	-152.17%
1960	1999	-376	12336.60	19271.09	31607.69	198.62 %	24502.95	(7,104.74)	-57.59%
1960	2000	-38	1182.80	10389.53	11572.33	206.84 %	2446.50	(9,125.83)	-771.54%
1960	2001	-33	1046.69	6848.63	7895.32	215.06 %	2251.01	(5,644.31)	-539.25%
		-943	**29596.06**	**82315.37**	**111911.43**		**56321.60**	**(55,589.83)**	**-187.83%**
1961	1995	-17	929.18	3959.98	4889.16	162.74 %	1512.15	(3,377.01)	-363.44%
1961	1996	-29	1610.84	3688.22	5299.06	170.96 %	2753.89	(2,545.17)	-158.00%
1961	1997	-21	1176.90	3670.14	4847.04	179.18 %	2108.77	(2,738.27)	-232.67%
1961	1998	-25	1494.52	7081.16	8575.68	187.40 %	2800.73	(5,774.95)	-386.41%
1961	1999	-19	952.49	4811.64	5764.13	195.62 %	1863.26	(3,900.87)	-409.54%
1961	2000	-14	691.99	1874.83	2566.82	203.84 %	1410.55	(1,156.27)	-167.09%
1961	2001	-25	1344.79	4275.96	5620.75	212.06 %	2851.76	(2,768.99)	-205.91%

Montana-Dakota Utilities Co.
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Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
		-150	**8200.71**	**29361.93**	**37562.64**		**15301.11**	**(22,261.53)**	**-271.46%**
1962	1995	-18	996.91	3950.11	4947.02	159.74 %	1592.46	(3,354.56)	-336.50%
1962	1996	-46	2569.22	5827.80	8397.02	167.96 %	4315.26	(4,081.76)	-158.87%
1962	1997	-29	1721.47	4901.01	6622.48	176.18 %	3032.89	(3,589.59)	-208.52%
1962	1998	-36	1990.99	6390.00	8380.99	184.40 %	3671.39	(4,709.60)	-236.55%
1962	1999	-26	1450.24	6543.68	7993.92	192.62 %	2793.45	(5,200.47)	-358.59%
1962	2000	-106	5997.24	6591.44	12588.68	200.84 %	12044.86	(543.82)	-9.07%
1962	2001	-34	1903.43	8664.58	10568.01	209.06 %	3979.31	(6,588.70)	-346.15%
		-295	**16629.50**	**42868.62**	**59498.12**		**31429.62**	**(28,068.50)**	**-168.79%**
1963	1995	-10	556.69	1998.26	2554.95	156.74 %	872.56	(1,682.39)	-302.21%
1963	1996	-67	3748.09	8329.06	12077.15	164.96 %	6182.85	(5,894.30)	-157.26%
1963	1997	-23	1283.14	2653.68	3936.82	173.18 %	2222.14	(1,714.68)	-133.63%
1963	1998	-28	1544.81	5889.36	7434.17	181.40 %	2802.29	(4,631.88)	-299.83%
1963	1999	-37	2070.67	4030.86	6101.53	189.62 %	3926.40	(2,175.13)	-105.04%
1963	2000	-25	1501.73	5407.08	6908.81	197.84 %	2971.02	(3,937.79)	-262.22%
1963	2001	-32	2020.34	3881.19	5901.53	206.06 %	4163.11	(1,738.42)	-86.05%
		-222	**12725.47**	**32189.49**	**44914.96**		**23140.37**	**(21,774.59)**	**-171.11%**
1964	1995	-23	1366.26	3863.11	5229.37	153.74 %	2100.49	(3,128.88)	-229.01%
1964	1996	111	-2734.09	5713.59	2979.50	161.96 %	-4428.13	(7,407.63)	270.94%
1964	1997	-26	7145.83	4731.32	11877.15	170.18 %	12160.77	283.62	3.97%
1964	1998	-38	2030.25	8000.77	10031.02	178.40 %	3621.97	(6,409.05)	-315.68%
1964	1999	-45	2452.85	9404.22	11857.07	186.62 %	4577.51	(7,279.56)	-296.78%
1964	2000	-37	2025.50	9908.42	11933.92	194.84 %	3946.48	(7,987.44)	-394.34%
1964	2001	-35	1984.76	7608.91	9593.67	203.06 %	4030.25	(5,563.42)	-280.31%
		-93	**14271.36**	**49230.34**	**63501.70**		**26009.34**	**(37,492.36)**	**-262.71%**
1965	1995	-15	811.89	1906.92	2718.81	150.74 %	1223.84	(1,494.97)	-184.13%
1965	1996	-23	1279.61	3252.58	4532.19	158.96 %	2034.07	(2,498.12)	-195.23%
1965	1997	-21	1159.78	4300.05	5459.83	167.18 %	1938.92	(3,520.91)	-303.58%
1965	1998	-24	1311.90	5526.91	6838.81	175.40 %	2301.07	(4,537.74)	-345.89%
1965	1999	-20	1115.37	4954.12	6069.49	183.62 %	2048.04	(4,021.45)	-360.55%
1965	2000	-17	1063.29	3511.19	4574.48	191.84 %	2039.82	(2,534.66)	-238.38%
1965	2001	-13	718.22	3737.22	4455.44	200.06 %	1436.87	(3,018.57)	-420.28%
		-133	**7460.06**	**27188.99**	**34649.05**		**13022.63**	**(21,626.42)**	**-289.90%**
1966	1995	-20	1529.72	3664.65	5194.37	147.74 %	2260.01	(2,934.36)	-191.82%
1966	1996	-34	2438.15	3138.22	5576.37	155.96 %	3802.54	(1,773.83)	-72.75%

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Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1966	1997	-16	1166.01	2506.78	3672.79	164.18 %	1914.36	(1,758.43)	-150.81%
1966	1998	-23	1704.85	5946.66	7651.51	172.40 %	2939.16	(4,712.35)	-276.41%
1966	1999	-22	1517.16	3812.54	5329.70	180.62 %	2740.29	(2,589.41)	-170.67%
1966	2000	-24	1732.50	4981.83	6714.33	188.84 %	3271.65	(3,442.68)	-198.71%
1966	2001	-25	1751.10	3295.34	5046.44	197.06 %	3450.72	(1,595.72)	-91.13%
		-164	**11839.49**	**27346.02**	**39185.51**		**20378.73**	**(18,806.78)**	**-158.85%**
1967	1995	-14	1033.36	2434.17	3467.53	144.74 %	1495.69	(1,971.84)	-190.82%
1967	1996	-15	1052.92	2074.78	3127.70	152.96 %	1610.55	(1,517.15)	-144.09%
1967	1997	-15	1071.34	2579.73	3651.07	161.18 %	1726.79	(1,924.28)	-179.61%
1967	1998	-23	1631.78	4871.26	6503.04	169.40 %	2764.24	(3,738.80)	-229.12%
1967	1999	-20	1431.18	4398.23	5829.41	177.62 %	2542.06	(3,287.35)	-229.70%
1967	2000	-16	1341.77	3445.33	4787.10	185.84 %	2493.55	(2,293.55)	-170.93%
1967	2001	-15	1202.85	2471.05	3673.90	194.06 %	2334.25	(1,339.65)	-111.37%
		-118	**8765.20**	**22274.55**	**31039.75**		**14967.13**	**(16,072.62)**	**-183.37%**
1968	1995	-12	913.73	2687.38	3601.11	141.74 %	1295.12	(2,305.99)	-252.37%
1968	1996	-26	1787.40	3272.29	5059.69	149.96 %	2680.39	(2,379.30)	-133.12%
1968	1997	-16	1139.40	2644.63	3784.03	158.18 %	1802.30	(1,981.73)	-173.93%
1968	1998	-21	1382.50	3743.95	5126.45	166.40 %	2300.48	(2,825.97)	-204.41%
1968	1999	-14	1053.03	3504.05	4557.08	174.62 %	1838.80	(2,718.28)	-258.14%
1968	2000	-17	1190.52	3126.19	4316.71	182.84 %	2176.75	(2,139.96)	-179.75%
1968	2001	-21	1460.87	4007.12	5467.99	191.06 %	2791.14	(2,676.85)	-183.24%
		-127	**8927.45**	**22985.61**	**31913.06**		**14884.98**	**(17,028.08)**	**-190.74%**
1969	1995	-18	1290.44	2911.17	4201.61	138.24 %	1783.90	(2,417.71)	-187.36%
1969	1996	-14	1008.29	1597.15	2605.44	146.46 %	1476.74	(1,128.70)	-111.94%
1969	1997	-21	1545.90	3578.09	5123.99	154.68 %	2391.20	(2,732.79)	-176.78%
1969	1998	-24	1902.04	5224.58	7126.62	162.90 %	3098.42	(4,028.20)	-211.78%
1969	1999	-30	2241.55	7838.36	10079.91	171.12 %	3835.74	(6,244.17)	-278.56%
1969	2000	-14	972.90	1637.32	2610.22	179.34 %	1744.80	(865.42)	-88.95%
1969	2001	-28	2051.80	4451.83	6503.63	187.56 %	3848.36	(2,655.27)	-129.41%
		-149	**11012.92**	**27238.50**	**38251.42**		**18179.16**	**(20,072.26)**	**-182.26%**
1970	1995	-16	2034.18	2074.80	4108.98	134.74 %	2740.85	(1,368.13)	-67.26%
1970	1996	-48	6195.20	9438.77	15633.97	142.96 %	8856.66	(6,777.31)	-109.40%
1970	1997	-74	8292.25	8299.56	16591.81	151.18 %	12536.22	(4,055.59)	-48.91%
1970	1998	-47	5656.41	8251.38	13907.79	159.40 %	9016.32	(4,891.47)	-86.48%
1970	1999	-37	4167.92	5425.41	9593.33	167.62 %	6986.27	(2,607.06)	-62.55%

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Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1970	2000	-19	2286.53	3778.49	6065.02	175.84 %	4020.63	(2,044.39)	-89.41%
1970	2001	-46	5221.62	7491.70	12713.32	184.06 %	9610.91	(3,102.41)	-59.41%
		-287	**33854.11**	**44760.11**	**78614.22**		**53767.86**	**(24,846.36)**	**-73.39%**
1971	1995	-7	652.66	982.89	1635.55	131.24 %	856.55	(779.00)	-119.36%
1971	1996	-19	1660.32	1499.54	3159.86	139.46 %	2315.48	(844.38)	-50.86%
1971	1997	-28	2733.52	4511.82	7245.34	147.68 %	4036.86	(3,208.48)	-117.38%
1971	1998	-21	1985.86	5557.47	7543.33	155.90 %	3095.96	(4,447.37)	-223.95%
1971	1999	-25	1980.71	3604.55	5585.26	164.12 %	3250.74	(2,334.52)	-117.86%
1971	2000	-24	1860.64	3310.83	5171.47	172.34 %	3206.63	(1,964.84)	-105.60%
1971	2001	-12	1110.67	3281.63	4392.30	180.56 %	2005.43	(2,386.87)	-214.90%
		-136	**11984.38**	**22748.73**	**34733.11**		**18767.65**	**(15,965.46)**	**-133.22%**
1972	1995	-11	1266.80	1224.06	2490.86	127.61 %	1616.56	(874.30)	-69.02%
1972	1996	-46	4932.98	3206.76	8139.74	135.83 %	6700.47	(1,439.27)	-29.18%
1972	1997	-42	3164.79	4884.61	8049.40	144.05 %	4558.88	(3,490.52)	-110.29%
1972	1998	-29	4117.84	6840.34	10958.18	152.27 %	6270.23	(4,687.95)	-113.84%
1972	1999	-62	6356.56	4849.90	11206.46	160.49 %	10201.64	(1,004.82)	-15.81%
1972	2000	-17	1627.01	2255.58	3882.59	168.71 %	2744.93	(1,137.66)	-69.92%
1972	2001	-29	3157.52	4170.01	7327.53	176.93 %	5586.60	(1,740.93)	-55.14%
		-236	**24623.50**	**27431.26**	**52054.76**		**37679.31**	**(14,375.45)**	**-58.38%**
1973	1995	-12	1188.95	1905.27	3094.22	123.98 %	1474.06	(1,620.16)	-136.27%
1973	1996	-35	3715.93	3933.98	7649.91	132.20 %	4912.46	(2,737.45)	-73.67%
1973	1997	-44	3887.42	2929.23	6816.65	140.42 %	5458.72	(1,357.93)	-34.93%
1973	1998	-21	2686.99	4476.43	7163.42	148.64 %	3993.94	(3,169.48)	-117.96%
1973	1999	-30	3224.70	7050.11	10274.81	156.86 %	5058.26	(5,216.55)	-161.77%
1973	2000	-25	2277.16	3623.33	5900.49	165.08 %	3759.14	(2,141.35)	-94.04%
1973	2001	-12	1117.03	2853.98	3971.01	173.30 %	1935.81	(2,035.20)	-182.20%
		-179	**18098.18**	**26772.33**	**44870.51**		**26592.39**	**(18,278.12)**	**-100.99%**
1974	1995	-15	1616.86	2078.99	3695.85	120.35 %	1945.89	(1,749.96)	-108.23%
1974	1996	-40	4474.75	5210.45	9685.20	128.57 %	5753.19	(3,932.01)	-87.87%
1974	1997	-32	4999.50	2734.53	7734.03	136.79 %	6838.82	(895.21)	-17.91%
1974	1998	-28	2672.50	3714.16	6386.66	145.01 %	3875.39	(2,511.27)	-93.97%
1974	1999	-36	2589.29	5717.53	8306.82	153.23 %	3967.57	(4,339.25)	-167.58%
1974	2000	-26	2454.24	4445.46	6899.70	161.45 %	3962.37	(2,937.33)	-119.68%
1974	2001	-20	2019.04	2661.41	4680.45	169.67 %	3425.71	(1,254.74)	-62.15%
		-197	**20826.18**	**26562.53**	**47388.71**		**29768.94**	**(17,619.77)**	**-84.60%**

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Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1975	1995	-27	2526.43	1932.05	4458.48	116.00 %	2930.66	(1,527.82)	-60.47%
1975	1996	-32	4496.93	2200.65	6697.58	124.22 %	5586.09	(1,111.49)	-24.72%
1975	1997	-23	3149.64	2960.32	6109.96	132.44 %	4171.38	(1,938.58)	-61.55%
1975	1998	-19	2435.59	2821.58	5257.17	140.66 %	3425.90	(1,831.27)	-75.19%
1975	1999	-10	1455.13	1880.61	3335.74	148.88 %	2166.40	(1,169.34)	-80.36%
1975	2000	-17	2456.32	2254.62	4710.94	157.10 %	3858.88	(852.06)	-34.69%
1975	2001	-19	2451.63	3346.18	5797.81	165.32 %	4053.03	(1,744.78)	-71.17%
		-147	**18971.67**	**17396.01**	**36367.68**		**26192.34**	**(10,175.34)**	**-53.63%**
1976	1995	-19	2104.80	2231.09	4335.89	111.65 %	2350.01	(1,985.88)	-94.35%
1976	1996	-176	8996.82	2271.22	11268.04	119.87 %	10784.49	(483.55)	-5.37%
1976	1997	-46	-429.63	3540.89	3111.26	128.09 %	-550.31	(3,661.57)	852.26%
1976	1998	-26	3089.68	4167.92	7257.60	136.31 %	4211.54	(3,046.06)	-98.59%
1976	1999	-16	1559.85	2291.02	3850.87	144.53 %	2254.45	(1,596.42)	-102.34%
1976	2000	-73	5936.03	4907.49	10843.52	152.75 %	9067.29	(1,776.23)	-29.92%
1976	2001	-23	2539.71	3595.01	6134.72	160.97 %	4088.17	(2,046.55)	-80.58%
		-379	**23797.26**	**23004.64**	**46801.90**		**32205.64**	**(14,596.26)**	**-61.34%**
1977	1995	-23	3043.23	2336.86	5380.09	107.30 %	3265.39	(2,114.70)	-69.49%
1977	1996	-69	9433.73	2576.61	12010.34	115.52 %	10897.84	(1,112.50)	-11.79%
1977	1997	-20	2862.50	2898.13	5760.63	123.74 %	3542.06	(2,218.57)	-77.50%
1977	1998	-11	1341.13	2477.60	3818.73	131.96 %	1769.76	(2,048.97)	-152.78%
1977	1999	-12	1460.33	3353.48	4813.81	140.18 %	2047.09	(2,766.72)	-189.46%
1977	2000	-20	2204.80	3526.61	5731.41	148.40 %	3271.92	(2,459.49)	-111.55%
1977	2001	-8	1132.32	1840.34	2972.66	156.62 %	1773.44	(1,199.22)	-105.91%
		-163	**21478.04**	**19009.63**	**40487.67**		**26567.50**	**(13,920.17)**	**-64.81%**
1978	1995	-9	1297.22	1717.37	3014.59	102.96 %	1335.62	(1,678.97)	-129.43%
1978	1996	-25	4078.65	4333.51	8412.16	111.18 %	4534.64	(3,877.52)	-95.07%
1978	1997	-15	2513.56	1537.13	4050.69	119.40 %	3001.19	(1,049.50)	-41.75%
1978	1998	-12	1547.62	2269.01	3816.63	127.62 %	1975.07	(1,841.56)	-118.99%
1978	1999	-7	973.65	1867.63	2841.28	135.84 %	1322.61	(1,518.67)	-155.98%
1978	2000	-10	1308.84	1963.13	3271.97	144.06 %	1885.51	(1,386.46)	-105.93%
1978	2001	-18	2515.63	3842.39	6358.02	152.28 %	3830.80	(2,527.22)	-100.46%
		-96	**14235.17**	**17530.17**	**31765.34**		**17885.44**	**(13,879.90)**	**-97.50%**
1979	1995	-9	1636.02	827.98	2464.00	98.62 %	1613.44	(850.56)	-51.99%
1979	1996	-20	3537.29	2517.95	6055.24	106.84 %	3779.24	(2,276.00)	-64.34%
1979	1997	-19	3612.50	1559.45	5171.95	115.06 %	4156.54	(1,015.41)	-28.11%

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Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1979	1998	-11	1568.70	2464.75	4033.45	123.28 %	1933.89	(2,099.56)	-133.84%
1979	1999	-22	3679.13	2783.41	6462.54	131.50 %	4838.06	(1,624.48)	-44.15%
1979	2000	-10	1981.22	1790.11	3771.33	139.72 %	2768.16	(1,003.17)	-50.63%
1979	2001	-11	2079.92	3047.33	5127.25	147.94 %	3077.03	(2,050.22)	-98.57%
		-102	**18094.78**	**14990.98**	**33085.76**		**22166.36**	**(10,919.40)**	**-60.35%**
1980	1995	-33	4290.88	2344.66	6635.54	94.28 %	4045.44	(2,590.10)	-60.36%
1980	1996	-26	3653.33	1960.69	5614.02	102.50 %	3744.66	(1,869.36)	-51.17%
1980	1997	-157	14182.91	4245.31	18428.22	110.72 %	15703.32	(2,724.90)	-19.21%
1980	1998	-58	7636.45	2187.13	9823.58	118.94 %	9082.79	(740.79)	-9.70%
1980	1999	-33	3865.60	2870.71	6736.31	127.16 %	4915.50	(1,820.81)	-47.10%
1980	2000	-47	5663.30	4376.92	10040.22	135.38 %	7666.98	(2,373.24)	-41.91%
1980	2001	-24	3113.89	3954.18	7068.07	143.60 %	4471.55	(2,596.52)	-83.39%
		-378	**42406.36**	**21939.60**	**64345.96**		**49630.24**	**(14,715.72)**	**-34.70%**
1981	1995	-34	3907.21	5017.43	8924.64	89.94 %	3514.14	(5,410.50)	-138.47%
1981	1996	-63	6899.47	5024.46	11923.93	98.16 %	6772.52	(5,151.41)	-74.66%
1981	1997	-26	3666.69	3958.52	7625.21	106.38 %	3900.62	(3,724.59)	-101.58%
1981	1998	-73	8107.27	5195.98	13303.25	114.60 %	9290.93	(4,012.32)	-49.49%
1981	1999	-28	4735.10	3930.50	8665.60	122.82 %	5815.65	(2,849.95)	-60.19%
1981	2000	-19	2653.78	2572.07	5225.85	131.04 %	3477.51	(1,748.34)	-65.88%
1981	2001	-25	3433.86	4612.83	8046.69	139.26 %	4781.99	(3,264.70)	-95.07%
		-268	**33403.38**	**30311.79**	**63715.17**		**37553.36**	**(26,161.81)**	**-78.32%**
1982	1995	-57	7715.23	2552.83	10268.06	85.60 %	6604.24	(3,663.82)	-47.49%
1982	1996	-220	28326.51	3147.67	31474.18	93.82 %	26575.93	(4,898.25)	-17.29%
1982	1997	-24	3982.37	3435.44	7417.81	102.04 %	4063.61	(3,354.20)	-84.23%
1982	1998	-59	12341.76	5078.24	17420.00	110.26 %	13608.02	(3,811.98)	-30.89%
1982	1999	-18	3624.06	2851.53	6475.59	118.48 %	4293.79	(2,181.80)	-60.20%
1982	2000	-11	2453.31	1998.63	4451.94	126.70 %	3108.34	(1,343.60)	-54.77%
1982	2001	-15	3648.81	1865.65	5514.46	134.92 %	4922.97	(591.49)	-16.21%
		-404	**62092.05**	**20929.99**	**83022.04**		**63176.90**	**(19,845.14)**	**-31.96%**
1983	1995	-8	1620.98	681.38	2302.36	81.26 %	1317.21	(985.15)	-60.77%
1983	1996	-15	3425.63	1756.18	5181.81	89.48 %	3065.25	(2,116.56)	-61.79%
1983	1997	-20	8568.52	1740.87	10309.39	97.70 %	8371.44	(1,937.95)	-22.62%
1983	1998	-11	2471.92	3358.29	5830.21	105.92 %	2618.26	(3,211.95)	-129.94%
1983	1999	-9	2216.01	2259.68	4475.69	114.14 %	2529.35	(1,946.34)	-87.83%
1983	2000	-16	3037.10	2005.19	5042.29	122.36 %	3716.20	(1,326.09)	-43.66%

Montana-Dakota Utilities Co.
Gas Services - Subplant Account 380
Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1983	2001	-6	882.39	503.20	1385.59	130.58 %	1152.22	(233.37)	-26.45%
		-85	**22222.55**	**12304.79**	**34527.34**		**22769.93**	**(11,757.41)**	**-52.91%**
1984	1995	-5	1188.64	626.13	1814.77	76.92 %	914.30	(900.47)	-75.76%
1984	1996	-13	3058.35	806.38	3864.73	85.14 %	2603.88	(1,260.85)	-41.23%
1984	1997	-6	1368.19	1144.11	2512.30	93.36 %	1277.34	(1,234.96)	-90.26%
1984	1998	-12	3098.80	2983.32	6082.12	101.58 %	3147.76	(2,934.36)	-94.69%
1984	1999	-8	1326.57	532.32	1858.89	109.80 %	1456.57	(402.32)	-30.33%
1984	2000	-15	2872.90	1827.80	4700.70	118.02 %	3390.60	(1,310.10)	-45.60%
1984	2001	-9	2412.52	1671.32	4083.84	126.24 %	3045.57	(1,038.27)	-43.04%
		-68	**15325.97**	**9591.38**	**24917.35**		**15836.02**	**(9,081.33)**	**-59.25%**
1985	1995	-8	2241.79	1465.76	3707.55	70.05 %	1570.37	(2,137.18)	-95.33%
1985	1996	-15	4299.74	1428.21	5727.95	78.27 %	3365.41	(2,362.54)	-54.95%
1985	1997	-4	1571.17	848.34	2419.51	86.49 %	1358.90	(1,060.61)	-67.50%
1985	1998	-15	4257.04	4039.92	8296.96	94.71 %	4031.84	(4,265.12)	-100.19%
1985	1999	-10	2753.13	1560.23	4313.36	102.93 %	2833.80	(1,479.56)	-53.74%
1985	2000	-3	1094.94	757.78	1852.72	111.15 %	1217.03	(635.69)	-58.06%
1985	2001	-11	3216.73	1528.63	4745.36	119.37 %	3839.81	(905.55)	-28.15%
		-66	**19434.54**	**11628.87**	**31063.41**		**18217.16**	**(12,846.25)**	**-66.10%**
1986	1995	-6	2359.19	2072.98	4432.17	63.18 %	1490.54	(2,941.63)	-124.69%
1986	1996	-18	6181.33	2940.54	9121.87	71.40 %	4413.47	(4,708.40)	-76.17%
1986	1997	-7	1786.61	721.89	2508.50	79.62 %	1422.50	(1,086.00)	-60.79%
1986	1998	-110	22872.25	1274.26	24146.51	87.84 %	20090.98	(4,055.53)	-17.73%
1986	1999	-6	2008.52	1006.50	3015.02	96.06 %	1929.38	(1,085.64)	-54.05%
1986	2000	-30	10556.17	3682.10	14238.27	104.28 %	11007.97	(3,230.30)	-30.60%
1986	2001	-53	12442.39	3109.32	15551.71	112.50 %	13997.69	(1,554.02)	-12.49%
		-230	**58206.46**	**14807.59**	**73014.05**		**54352.53**	**(18,661.52)**	**-32.06%**
1987	1995	-14	4004.64	1632.61	5637.25	56.31 %	2255.01	(3,382.24)	-84.46%
1987	1996	-24	6291.31	1887.55	8178.86	64.53 %	4059.78	(4,119.08)	-65.47%
1987	1997	-11	2580.11	1350.38	3930.49	72.75 %	1877.03	(2,053.46)	-79.59%
1987	1998	-11	3438.32	832.41	4270.73	80.97 %	2784.01	(1,486.72)	-43.24%
1987	1999	-14	4399.08	2466.70	6865.78	89.19 %	3923.54	(2,942.24)	-66.88%
1987	2000	-51	12585.04	3067.57	15652.61	97.41 %	12259.09	(3,393.52)	-26.96%
1987	2001	-11	2485.39	3043.44	5528.83	105.63 %	2625.32	(2,903.51)	-116.82%
		-136	**35783.89**	**14280.66**	**50064.55**		**29783.78**	**(20,280.77)**	**-56.68%**
1988	1995	-13	3163.75	2015.59	5179.34	49.44 %	1564.16	(3,615.18)	-114.27%

Montana-Dakota Utilities Co.
Gas Services - Subplant Account 380
Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1988	1996	-6	1615.24	342.43	1957.67	57.66 %	931.35	(1,026.32)	-63.54%
1988	1997	-5	1351.81	892.02	2243.83	65.88 %	890.57	(1,353.26)	-100.11%
1988	1998	-8	2502.17	668.98	3171.15	74.10 %	1854.11	(1,317.04)	-52.64%
1988	1999	-9	2531.02	1875.10	4406.12	82.32 %	2083.54	(2,322.58)	-91.76%
1988	2000	-18	5146.34	2201.35	7347.69	90.54 %	4659.50	(2,688.19)	-52.23%
1988	2001	-9	2356.97	1497.34	3854.31	98.76 %	2327.74	(1,526.57)	-64.77%
		-68	**18667.30**	**9492.81**	**28160.11**		**14310.97**	**(13,849.14)**	**-74.19%**
1989	1995	-12	3148.31	1995.68	5143.99	42.57 %	1340.24	(3,803.75)	-120.82%
1989	1996	-17	4561.66	1845.35	6407.01	50.79 %	2316.87	(4,090.14)	-89.66%
1989	1997	-7	2433.75	1084.99	3518.74	59.01 %	1436.16	(2,082.58)	-85.57%
1989	1998	-6	1824.32	569.18	2393.50	67.23 %	1226.49	(1,167.01)	-63.97%
1989	1999	-10	2788.01	1167.15	3955.16	75.45 %	2103.55	(1,851.61)	-66.41%
1989	2000	-5	1547.85	359.70	1907.55	83.67 %	1295.09	(612.46)	-39.57%
1989	2001	-5	1383.67	1758.69	3142.36	91.89 %	1271.45	(1,870.91)	-135.21%
		-62	**17687.57**	**8780.74**	**26468.31**		**10989.85**	**(15,478.46)**	**-87.51%**
1990	1995	-7	1663.25	774.92	2438.17	35.70 %	593.78	(1,844.39)	-110.89%
1990	1996	-11	2263.36	1118.69	3382.05	43.92 %	994.07	(2,387.98)	-105.51%
1990	1997	-3	780.81	1843.33	2624.14	52.14 %	407.11	(2,217.03)	-283.94%
1990	1998	-11	2674.88	1675.36	4350.24	60.36 %	1614.56	(2,735.68)	-102.27%
1990	1999	-7	1825.88	1099.11	2924.99	68.58 %	1252.19	(1,672.80)	-91.62%
1990	2000	-6	1510.87	959.84	2470.71	76.80 %	1160.35	(1,310.36)	-86.73%
1990	2001	-8	2195.25	1945.99	4141.24	85.02 %	1866.40	(2,274.84)	-103.63%
		-53	**12914.30**	**9417.24**	**22331.54**		**7888.46**	**(14,443.08)**	**-111.84%**
1991	1995	-17	4752.55	1302.81	6055.36	28.83 %	1370.16	(4,685.20)	-98.58%
1991	1996	-14	3523.44	906.74	4430.18	37.05 %	1305.43	(3,124.75)	-88.68%
1991	1997	-8	2580.19	1040.97	3621.16	45.27 %	1168.05	(2,453.11)	-95.07%
1991	1998	-10	2930.08	1351.15	4281.23	53.49 %	1567.30	(2,713.93)	-92.62%
1991	1999	-2	459.08	535.44	994.52	61.71 %	283.30	(711.22)	-154.92%
1991	2000	-4	1382.31	687.85	2070.16	69.93 %	966.65	(1,103.51)	-79.83%
1991	2001	-15	3513.41	3738.09	7251.50	78.15 %	2745.73	(4,505.77)	-128.24%
		-70	**19141.06**	**9563.05**	**28704.11**		**9406.62**	**(19,297.49)**	**-100.82%**
1992	1995	-6	1327.62	1278.19	2605.81	21.96 %	291.55	(2,314.26)	-174.32%
1992	1996	-7	1914.68	552.31	2466.99	30.18 %	577.85	(1,889.14)	-98.67%
1992	1997	-7	2113.76	470.49	2584.25	38.40 %	811.68	(1,772.57)	-83.86%
1992	1998	-4	1296.30	566.48	1862.78	46.62 %	604.34	(1,258.44)	-97.08%

Montana-Dakota Utilities Co.
Gas Services - Subplant Account 380
Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1992	1999	-13	2658.56	1668.57	4327.13	54.84 %	1457.95	(2,869.18)	-107.92%
1992	2000	-14	1739.62	3398.90	5138.52	63.06 %	1097.00	(4,041.52)	-232.32%
1992	2001	-7	1798.70	1217.29	3015.99	71.28 %	1282.11	(1,733.88)	-96.40%
		-58	**12849.24**	**9152.23**	**22001.47**		**6122.48**	**(15,878.99)**	**-123.58%**
1993	1995	-9	2122.39	-8091.12	-5968.73	15.09 %	320.27	6,289.00	296.32%
1993	1996	-16	3877.09	1396.31	5273.40	23.31 %	903.75	(4,369.65)	-112.70%
1993	1997	-21	18415.36	2122.36	20537.72	31.53 %	5806.36	(14,731.36)	-79.99%
1993	1998	-10	2679.02	1112.74	3791.76	39.75 %	1064.91	(2,726.85)	-101.79%
1993	1999	-8	3840.82	219.59	4060.41	47.97 %	1842.44	(2,217.97)	-57.75%
1993	2000	-16	6174.39	4419.80	10594.19	56.19 %	3469.39	(7,124.80)	-115.39%
1993	2001	-29	7991.47	4552.23	12543.70	64.41 %	5147.31	(7,396.39)	-92.55%
		-109	**45100.54**	**5731.91**	**50832.45**		**18554.43**	**(32,278.02)**	**-71.57%**
1994	1995	-9	1982.84	1221.30	3204.14	8.22 %	162.99	(3,041.15)	-153.37%
1994	1996	-13	3366.98	2139.56	5506.54	16.44 %	553.53	(4,953.01)	-147.11%
1994	1997	-15	3612.22	362.99	3975.21	24.66 %	890.77	(3,084.44)	-85.39%
1994	1998	-10	3193.98	4762.34	7956.32	32.88 %	1050.18	(6,906.14)	-216.22%
1994	1999	-13	4606.03	2481.85	7087.88	41.10 %	1893.08	(5,194.80)	-112.78%
1994	2000	-13	4928.89	1350.10	6278.99	49.32 %	2430.93	(3,848.06)	-78.07%
1994	2001	-12	3503.05	1889.93	5392.98	57.54 %	2015.65	(3,377.33)	-96.41%
		-85	**25193.99**	**14208.07**	**39402.06**		**8997.13**	**(30,404.93)**	**-120.68%**
1995	1996	-5	1744.16	479.36	2223.52	8.22 %	143.37	(2,080.15)	-119.26%
1995	1997	-7	2420.53	681.95	3102.48	16.44 %	397.94	(2,704.54)	-111.73%
1995	1998	-7	1950.69	1374.92	3325.61	24.66 %	481.04	(2,844.57)	-145.82%
1995	1999	-9	1983.26	946.26	2929.52	32.88 %	652.10	(2,277.42)	-114.83%
1995	2000	-7	1883.56	693.65	2577.21	41.10 %	774.14	(1,803.07)	-95.73%
1995	2001	-16	4822.65	3183.69	8006.34	49.32 %	2378.53	(5,627.81)	-116.70%
		-51	**14804.85**	**7359.83**	**22164.68**		**2448.59**	**(11,709.75)**	**-79.09%**
1996	1997	-8	2620.11	430.80	3050.91	8.22 %	215.37	(2,835.54)	-108.22%
1996	1998	-10	4477.87	2194.23	6672.10	16.44 %	736.16	(5,935.94)	-132.56%
1996	1999	-8	2898.10	1091.25	3989.35	24.66 %	714.67	(3,274.68)	-112.99%
1996	2000	-7	1811.46	553.94	2365.40	32.88 %	595.61	(1,769.79)	-97.70%
1996	2001	-9	3387.64	794.37	4182.01	41.10 %	1392.32	(2,789.69)	-82.35%
		-42	**15195.18**	**5064.59**	**20259.77**		**3654.13**	**(16,605.64)**	**-109.28%**
1997	1997	-6	1706.00	315.52	2021.52	0.00 %	0.00	(2,021.52)	-118.49%
1997	1998	-8	2802.21	614.93	3417.14	8.22 %	230.34	(3,186.80)	-113.72%

Montana-Dakota Utilities Co.
Gas Services - Subplant Account 380
Depreciation Reserve

Vint. Year	Trans. Yr.	Qty of Service Retired	Original Cost Of Plant Retirement	Removal Cost	Total Cost	Accum. Depr. Rate Percent	Accum. Depr. Total	Over/(Under) Recovery	Under/Over Recovered Percent
1997	1999	-5	1262.25	670.94	1933.19	16.44 %	207.51	(1,725.68)	-136.71%
1997	2000	-14	2558.90	1064.52	3623.42	24.66 %	631.02	(2,992.40)	-116.94%
1997	2001	-8	2886.46	1173.64	4060.10	32.88 %	949.07	(3,111.03)	-107.78%
		-41	**11215.82**	**3839.55**	**15055.37**		**2017.94**	**(13,037.43)**	**-116.24%**
1998	1998	-2	4264.51	1063.76	5328.27	0.00 %	0.00	(5,328.27)	-124.94%
1998	1999	-7	2517.22	1212.76	3729.98	8.22 %	206.92	(3,523.06)	-139.96%
1998	2000	-4	1120.69	887.43	2008.12	16.44 %	184.24	(1,823.88)	-162.75%
1998	2001	-3	907.92	744.81	1652.73	24.66 %	223.89	(1,428.84)	-157.38%
		-16	**8810.34**	**3908.76**	**12719.10**		**615.05**	**(12,104.05)**	**-137.38%**
1999	1999	-1	542.02	14.64	556.66	0.00 %	0.00	(556.66)	-102.70%
1999	2000	-4	1020.94	626.35	1647.29	8.22 %	83.92	(1,563.37)	-153.13%
1999	2001	-8	1866.25	959.43	2825.68	16.44 %	306.81	(2,518.87)	-134.97%
		-13	**3429.21**	**1600.42**	**5029.63**		**390.73**	**(4,638.90)**	**-135.28%**
2000	2001	-10	3124.85	919.06	4043.91	8.22 %	256.86	(3,787.05)	-121.19%
		-10	**3124.85**	**919.06**	**4043.91**		**256.86**	**(3,787.05)**	**-121.19%**
2001	2001	-1	205.25	214.25	419.50	0.00 %	0.00	(419.50)	-204.38%
		-1	**205.25**	**214.25**	**419.50**		**0.00**	**(419.50)**	**-204.38%**
Total		**-11,077**	**$968,194.63**	**$1,339,639.94**	**$2,307,834.57**		**$1,200,859.04**	**($1,098,969.19)**	**-113.51%**

Ratio of Removal Cost to Original Cost 138%

MONTANA-DAKOTA UTILITIES CO.
LATE FILED EXHIBITS
CASE NO. PU-399-02-183

Late Filed Exhibit 2

Provide the number of service lines retired that coincides with the information in Late Filed Exhibit 1.

Response:

Please see Late Filed Exhibit 1, Attachment A.

MONTANA-DAKOTA UTILITIES CO.
LATE FILED EXHIBITS
CASE NO. PU-399-02-183

Late Filed Exhibit 3

Provide the details on the sale of the Schuchart Building including who it was sold to, when it was sold, the purchase price, original cost of the building, a copy of the journal entries recording the sale and a copy of the tax appraisal at the time of the sale. Did the Company have an appraisal performed for purposes of the sale?

Response:

The Schuchart Building was sold to FutureSource Capital Corp., an indirect wholly owned subsidiary of MDU Resources Group, Inc., on July 1, 2001. The transfer price was the net book value at the time of transfer including land, building, and appurtenances. A summary of the transaction by sub plant account number is provided in Attachment A. A copy of the Transaction Journal is provided in Attachment B. The building was centrally assessed so there is no tax appraisal available. The Company did not have an appraisal performed for purposes of the transfer. However, there was an appraisal performed for another purpose at about the time of the transfer. That appraisal indicated a market value of the property of $2,700,000. It should be noted that the appraisal covers the land and the building only. The net book value of the land and building at the time of transfer was $3,198,359 as shown on Attachment A. A copy of the appraisal letter is included as Attachment C.

Description	LOCATION	Original Cost of Facilities	Accumulatd Provision for Depreciatn	Net Book Value or Purchase Price
00001 Montana Dakota Utilities Co.				
030 Misc Intangible Plant				
94 1994	900004	107,051.31	103,028.59-	4,022.72
030 Misc Intangible Plant		107,051.31	103,028.59-	4,022.72
890 Land and Land Rights - General				
B95 Beginning Balance Asset	900004	169,438.01		169,438.01
890 Land and Land Rights - General		169,438.01		169,438.01
900 Structures&Improvement-General				
00 2000	900004	502,495.67	15,685.66-	486,810.01
94 1994	900004	1,785,138.94	130,611.73-	1,654,527.21
95 1995	900004	265,360.20	55,314.24-	210,045.96
97 1997	900004	732,347.01	70,845.64-	661,501.37
99 1999	900004	17,347.62	1,311.31-	16,036.31
900 Structures&Improvement-General		3,302,689.44	273,768.58-	3,028,920.86
911 Office Furniture & Equipment				
B95 Beginning Balance Asset	900004	50,874.90	20,616.98-	30,257.92
00 2000	900004	211,736.70	3,242.85-	208,493.85
01 2001	900004	56,117.20	118.28-	55,998.92
95 1995	900004	80,926.42	8,460.81-	72,465.61
96 1996	900004	16,146.94	1,336.71-	14,810.23
97 1997	900004	305,016.60	16,758.67-	288,257.93
98 1998	900004	23,173.23	508.55	23,681.78
99 1999	900004	38,126.78	1,318.62-	36,808.16
911 Office Furniture & Equipment		782,118.77	51,344.37-	730,774.40
913 Computer Equip.-PC				
00 2000	900004	120,601.32	15,117.26-	105,484.06
01 2001	900004	121,441.13	2,969.70-	118,471.43
89 1989	900004	8,497.63	11,950.03-	3,452.40-
90 1990	900004	49,414.59	67,928.76-	18,514.17-
91 1991	900004	24,089.06	28,859.57-	4,770.51-
92 1992	900004	35,913.29	41,838.67-	5,925.38-
93 1993	900004	60,616.43	61,327.87-	711.44-
94 1994	900004	88,524.68	76,514.02-	12,010.66
95 1995	900004	24,754.58	17,092.95-	7,661.63
96 1996	900004	64,719.88	39,189.07-	25,530.81
97 1997	900004	65,477.53	29,823.04-	35,654.49
98 1998	900004	56,724.97	20,573.28-	36,151.69
99 1999	900004	75,884.88	16,794.60-	59,090.28
913 Computer Equip.-PC		796,659.97	429,978.82-	366,681.15
915 Computer Equip.-Other				

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Late Filed Exhibit 3
Attachment A
Page 1 of 2

Description	LOCATION	Original Cost of Facilities	Accumulatd Provision for Depreciatn	Net Book Value or Purchase Price
00 2000	900004	3,346.85	197.01-	3,149.84
915 Computer Equip.-Other		3,346.85	197.01-	3,149.84
973 General Telephone Commun. Equi				
00 2000	900004	3,197.49	291.30-	2,906.19
95 1995	900004	777.85	425.47-	352.38
97 1997	900004	25,354.26	9,518.22-	15,836.04
973 General Telephone Commun. Equi		29,329.60	10,234.99-	19,094.61
978 Network Equipment				
00 2000	900004	142,484.50	10,472.34-	132,012.16
95 1995	900004	6,977.08	879.45-	6,097.63
96 1996	900004	809.13	480.69-	328.44
97 1997	900004	20,408.93	8,930.10-	11,478.83
978 Network Equipment		170,679.64	20,762.58-	149,917.06
980 Miscellaneous Equipment				
00 2000	900004	30,100.53	740.16-	29,360.37
01 2001	900004	29,143.71	241.90-	28,901.81
96 1996	900004	24,713.34	3,350.02-	21,363.32
97 1997	900004	46,218.80	4,294.44-	41,924.36
980 Miscellaneous Equipment		130,176.38	8,626.52-	121,549.86
00001 Montana Dakota Utilities Co.		5,491,489.97	897,941.46-	4,593,548.51

Case No. PU-399-02-183
Late Filed Exhibit 3
Attachment B

ATTACHMENT B

Company 1 Montana Dakota Utilities Co.
Tax ID 410423660
From 07/01/01 Thru 07/31/01

Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
AD	540189	00001	07/31/01	1.1110.303	Misc. Intangible Plant	107,051.31			119228 0005	
			07/31/01	1.1010.303	Misc. Intangible Plant		107,051.31		119228 0005	
			07/31/01	1.4211	Gain on Disp. of Property	169,438.01			119228 0010	
			07/31/01	1.1010.3890	Land and Land Rights		169,438.01		119228 0010	
			07/31/01	1.1080.390	Structures & Improvements	18,714.54			119228 0020	
			07/31/01	1.1010.390	Structures & Improvements		18,714.54		119228 0020	
			07/31/01	1.1080.390	Structures & Improvements	70,066.44			119228 0022	
			07/31/01	1.1010.390	Structures & Improvements		70,066.44		119228 0022	
			07/31/01	1.1080.390	Structures & Improvements	25,703.20			119228 0030	
			07/31/01	1.1010.390	Structures & Improvements		25,703.20		119228 0030	
			07/31/01	1.1080.390	Structures & Improvements	6,433.13			119228 0038	
			07/31/01	1.1010.390	Structures & Improvements		6,433.13		119228 0038	
			07/31/01	1.1080.390	Structures & Improvements	5,724.95			119228 0041	
			07/31/01	1.1010.390	Structures & Improvements		5,724.95		119228 0041	
			07/31/01	1.1080.390	Structures & Improvements	1,879.18			119228 0047	
			07/31/01	1.1010.390	Structures & Improvements		1,879.18		119228 0047	
			07/31/01	1.1080.390	Structures & Improvements	23,926.60			119228 0050	
			07/31/01	1.1010.390	Structures & Improvements		23,926.60		119228 0050	
			07/31/01	1.1080.390	Structures & Improvements	43,028.39			119228 0068	
			07/31/01	1.1010.390	Structures & Improvements		43,028.39		119228 0068	
			07/31/01	1.1080.390	Structures & Improvements	8,171.99			119228 0086	
			07/31/01	1.1010.390	Structures & Improvements		8,171.99		119228 0086	
			07/31/01	1.1080.390	Structures & Improvements	26,359.13			119228 0092	
			07/31/01	1.1010.390	Structures & Improvements		26,359.13		119228 0092	
			07/31/01	1.1080.390	Structures & Improvements	31,656.41			119228 0095	
			07/31/01	1.1010.390	Structures & Improvements		31,656.41		119228 0095	
			07/31/01	1.1080.390	Structures & Improvements	1,572.34			119228 0101	
			07/31/01	1.1010.390	Structures & Improvements		1,572.34		119228 0101	
			07/31/01	1.1080.390	Structures & Improvements	2,123.90			119228 0110	
			07/31/01	1.1010.390	Structures & Improvements		2,123.90		119228 0110	
			07/31/01	1.1080.390	Structures & Improvements	11,127.60			119228 0089	
			07/31/01	1.1010.390	Structures & Improvements		11,127.60		119228 0089	
			07/31/01	1.1080.390	Structures & Improvements	67,753.21			119228 0032	
			07/31/01	1.1010.390	Structures & Improvements		67,753.21		119228 0032	
			07/31/01	1.1080.390	Structures & Improvements	63,775.33			119228 0029	
			07/31/01	1.1010.390	Structures & Improvements		63,775.33		119228 0029	
			07/31/01	1.1080.390	Structures & Improvements	832,010.97			119228 0020	
			07/31/01	1.1010.390	Structures & Improvements		832,010.97		119228 0020	
			07/31/01	1.1080.390	Structures & Improvements	286,196.71			119228 0021	
			07/31/01	1.1010.390	Structures & Improvements		286,196.71		119228 0021	
			07/31/01	1.1080.390	Structures & Improvements	22,667.14			119228 0023	
			07/31/01	1.1010.390	Structures & Improvements		22,667.14		119228 0023	
			07/31/01	1.1080.390	Structures & Improvements	61,912.61			119228 0032	
			07/31/01	1.1010.390	Structures & Improvements		61,912.61		119228 0032	
			07/31/01	1.1080.390	Structures & Improvements	6,447.89			119228 0035	
			07/31/01	1.1010.390	Structures & Improvements		6,447.89		119228 0035	
			07/31/01	1.1080.390	Structures & Improvements	21,985.15			119228 0038	
			07/31/01	1.1010.390	Structures & Improvements		21,985.15		119228 0038	
			07/31/01	1.1080.390	Structures & Improvements	13,709.78			119228 0041	

Company 1 Montana Dakota Utilities Co.
Tax ID 410423660
From 07/01/01 Thru 07/31/01

Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.390	Structures & Improvements		13,709.78	119228 0041		
			07/31/01	1.1080.390	Structures & Improvements	8,910.94		119228 0044		
			07/31/01	1.1010.390	Structures & Improvements		8,910.94	119228 0044		
			07/31/01	1.1080.390	Structures & Improvements	12,670.67		119228 0047		
			07/31/01	1.1010.390	Structures & Improvements		12,670.67	119228 0047		
			07/31/01	1.1080.390	Structures & Improvements	98,293.12		119228 0050		
			07/31/01	1.1010.390	Structures & Improvements		98,293.12	119228 0050		
			07/31/01	1.1080.390	Structures & Improvements	2,970.56		119228 0053		
			07/31/01	1.1010.390	Structures & Improvements		2,970.56	119228 0053		
			07/31/01	1.1080.390	Structures & Improvements	17,454.17		119228 0056		
			07/31/01	1.1010.390	Structures & Improvements		17,454.17	119228 0056		
			07/31/01	1.1080.390	Structures & Improvements	16,823.98		119228 0059		
			07/31/01	1.1010.390	Structures & Improvements		16,823.98	119228 0059		
			07/31/01	1.1080.390	Structures & Improvements	35,717.31		119228 0065		
			07/31/01	1.1010.390	Structures & Improvements		35,717.31	119228 0065		
			07/31/01	1.1080.390	Structures & Improvements	53,542.13		119228 0068		
			07/31/01	1.1010.390	Structures & Improvements		53,542.13	119228 0068		
			07/31/01	1.1080.390	Structures & Improvements	2,970.56		119228 0074		
			07/31/01	1.1010.390	Structures & Improvements		2,970.56	119228 0074		
			07/31/01	1.1080.390	Structures & Improvements	25,447.13		119228 0086		
			07/31/01	1.1010.390	Structures & Improvements		25,447.13	119228 0086		
			07/31/01	1.1080.390	Structures & Improvements	106,587.73		119228 0092		
			07/31/01	1.1080.390	Structures & Improvements	5,717.31		119228 0101		
			07/31/01	1.1010.390	Structures & Improvements		5,717.31	119228 0101		
			07/31/01	1.1080.390	Structures & Improvements	39,536.70		119228 0107		
			07/31/01	1.1010.390	Structures & Improvements		39,536.70	119228 0107		
			07/31/01	1.1080.390	Structures & Improvements	108,962.68		119228 0113		
			07/31/01	1.1010.390	Structures & Improvements		108,962.68	119228 0113		
			07/31/01	1.1080.390	Structures & Improvements	4,603.70		119228 0062		
			07/31/01	1.1010.390	Structures & Improvements		4,603.70	119228 0062		
			07/31/01	1.1080.390	Structures & Improvements	931.95		119228 0110		
			07/31/01	1.1010.390	Structures & Improvements		931.95	119228 0110		
			07/31/01	1.1080.390	Structures & Improvements	14,208.78		119228 0101		
			07/31/01	1.1010.390	Structures & Improvements		14,208.78	119228 0101		
			07/31/01	1.1080.390	Structures & Improvements	93,871.28		119228 0068		
			07/31/01	1.1010.390	Structures & Improvements		93,871.28	119228 0068		
			07/31/01	1.1080.390	Structures & Improvements	97,709.65		119228 0032		
			07/31/01	1.1010.390	Structures & Improvements		97,709.65	119228 0032		
			07/31/01	1.1080.390	Structures & Improvements	125,668.70		119228 0030		
			07/31/01	1.1010.390	Structures & Improvements		125,668.70	119228 0030		
			07/31/01	1.1080.390	Structures & Improvements	61,476.34		119228 0050		
			07/31/01	1.1010.390	Structures & Improvements		61,476.34	119228 0050		
			07/31/01	1.1080.390	Structures & Improvements	174,534.43		119228 0022		
			07/31/01	1.1010.390	Structures & Improvements		174,534.43	119228 0022		
			07/31/01	1.1080.390	Structures & Improvements	14,549.20		119228 0069		
			07/31/01	1.1010.390	Structures & Improvements		14,549.20	119228 0069		
			07/31/01	1.1080.390	Structures & Improvements	1,481.44		119228 0086		
			07/31/01	1.1010.390	Structures & Improvements		1,481.44	119228 0086		

Company 1 Montana Dakota Utilities Co.
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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.390	Structures & Improvements	5,259.10		119228 0095		
			07/31/01	1.1010.390	Structures & Improvements		5,259.10	119228 0095		
			07/31/01	1.1080.390	Structures & Improvements	2,093.42		119228 0089		
			07/31/01	1.1010.390	Structures & Improvements		2,093.42	119228 0089		
			07/31/01	1.1080.390	Structures & Improvements	15,254.20		119228 0028		
			07/31/01	1.1010.390	Structures & Improvements		15,254.20	119228 0028		
			07/31/01	1.1080.390	Structures & Improvements	35,946.14		119228 0032		
			07/31/01	1.1010.390	Structures & Improvements		35,946.14	119228 0032		
			07/31/01	1.1080.390	Structures & Improvements	19,012.58		119228 0020		
			07/31/01	1.1010.390	Structures & Improvements		19,012.58	119228 0020		
			07/31/01	1.1080.390	Structures & Improvements	48,762.08		119228 0022		
			07/31/01	1.1010.390	Structures & Improvements		48,762.08	119228 0022		
			07/31/01	1.1080.390	Structures & Improvements	2,090.20		119228 0029		
			07/31/01	1.1010.390	Structures & Improvements		2,090.20	119228 0029		
			07/31/01	1.1080.390	Structures & Improvements	13,327.73		119228 0069		
			07/31/01	1.1010.390	Structures & Improvements		13,327.73	119228 0069		
			07/31/01	1.1080.390	Structures & Improvements	12,116.52		119228 0095		
			07/31/01	1.1010.390	Structures & Improvements		12,116.52	119228 0095		
			07/31/01	1.1080.390	Structures & Improvements	17,961.30		119228 0098		
			07/31/01	1.1010.390	Structures & Improvements		17,961.30	119228 0098		
			07/31/01	1.1080.390	Structures & Improvements	236.52		119228 0022		
			07/31/01	1.1010.390	Structures & Improvements		236.52	119228 0022		
			07/31/01	1.1080.390	Structures & Improvements	25,134.40		119228 0068		
			07/31/01	1.1010.390	Structures & Improvements		25,134.40	119228 0068		
			07/31/01	1.1080.390	Structures & Improvements	20,570.03		119228 0068		
			07/31/01	1.1010.390	Structures & Improvements		20,570.03	119228 0068		
			07/31/01	1.1080.390	Structures & Improvements	809.60		119228 0110		
			07/31/01	1.1010.390	Structures & Improvements		809.60	119228 0110		
			07/31/01	1.1080.390	Structures & Improvements	46,257.94		119228 0030		
			07/31/01	1.1010.390	Structures & Improvements		46,257.94	119228 0030		
			07/31/01	1.1080.390	Structures & Improvements	29,606.88		119228 0050		
			07/31/01	1.1010.390	Structures & Improvements		29,606.88	119228 0050		
			07/31/01	1.1080.390	Structures & Improvements	4,376.81		119228 0044		
			07/31/01	1.1010.390	Structures & Improvements		4,376.81	119228 0044		
			07/31/01	1.1080.390	Structures & Improvements	2,491.78		119228 0101		
			07/31/01	1.1010.390	Structures & Improvements		2,491.78	119228 0101		
			07/31/01	1.1080.390	Structures & Improvements	105,103.47		119228 0032		
			07/31/01	1.1010.390	Structures & Improvements		105,103.47	119228 0032		
			07/31/01	1.1080.390	Structures & Improvements	330.20		119228 0038		
			07/31/01	1.1010.390	Structures & Improvements		330.20	119228 0038		
			07/31/01	1.1080.390	Structures & Improvements	110,807.54		119228 0092		
			07/31/01	1.1010.390	Structures & Improvements		110,807.54	119228 0092		
			07/31/01	1.1080.390	Structures & Improvements	2,903.61		119228 0032		
			07/31/01	1.1010.390	Structures & Improvements		2,903.61	119228 0032		
			07/31/01	1.1080.390	Structures & Improvements	542.56		119228 0068		
			07/31/01	1.1010.390	Structures & Improvements		542.56	119228 0068		
			07/31/01	1.1080.390	Structures & Improvements	4,107.78		119228 0044		
			07/31/01	1.1010.390	Structures & Improvements		4,107.78	119228 0044		
			07/31/01	1.1080.3911	Office Furniture & Equipment	879.12		119228 0125		

Company 1 Montana Dakota Utilities Co.
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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3911	Office Furniture & Equipment		879.12	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	879.12		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		879.12	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	737.79		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		737.79	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	737.79		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		737.79	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	224.59		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		224.59	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	224.59		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		224.59	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	224.59		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		224.59	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	652.60		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		652.60	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	751.22		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		751.22	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	547.28		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		547.28	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	618.51		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		618.51	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	388.26		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		388.26	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	747.09		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		747.09	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	988.20		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		988.20	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	988.20		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		988.20	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	224.59		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		224.59	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	547.28		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		547.28	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	547.28		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		547.28	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	644.34		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		644.34	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	293.26		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		293.26	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	48,144.21		119228 0127		
			07/31/01	1.1010.3911	Office Furniture & Equipment		48,144.21	119228 0127		
			07/31/01	1.1080.3911	Office Furniture & Equipment	6,405.31		119228 0129		
			07/31/01	1.1010.3911	Office Furniture & Equipment		6,405.31	119228 0129		
			07/31/01	1.1080.3911	Office Furniture & Equipment	247.93		119228 0131		
			07/31/01	1.1010.3911	Office Furniture & Equipment		247.93	119228 0131		
			07/31/01	1.1080.3911	Office Furniture & Equipment	3,915.56		119228 0133		
			07/31/01	1.1010.3911	Office Furniture & Equipment		3,915.56	119228 0133		
			07/31/01	1.1080.3911	Office Furniture & Equipment	10,367.71		119228 0135		
			07/31/01	1.1010.3911	Office Furniture & Equipment		10,367.71	119228 0135		

Company 1 Montana Dakota Utilities Co.
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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3911	Office Furniture & Equipment	817.03		119228 0139		
			07/31/01	1.1010.3911	Office Furniture & Equipment		817.03	119228 0139		
			07/31/01	1.1080.3911	Office Furniture & Equipment	501.01		119228 0137		
			07/31/01	1.1010.3911	Office Furniture & Equipment		501.01	119228 0137		
			07/31/01	1.1080.3911	Office Furniture & Equipment	577.70		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		577.70	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	605.26		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		605.26	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	605.26		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		605.26	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	605.26		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		605.26	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	655.08		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		655.08	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	966.72		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		966.72	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	605.26		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		605.26	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	655.08		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		655.08	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	655.08		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		655.08	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	655.08		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		655.08	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	450.50		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		450.50	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	655.08		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		655.08	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	517.28		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		517.28	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	486.00		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		486.00	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	420.11		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		420.11	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	608.59		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		608.59	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	537.76		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		537.76	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	252.36		119228 0129		
			07/31/01	1.1010.3911	Office Furniture & Equipment		252.36	119228 0129		
			07/31/01	1.1080.3911	Office Furniture & Equipment	549.62		119228 0145		
			07/31/01	1.1010.3911	Office Furniture & Equipment		549.62	119228 0145		
			07/31/01	1.1080.3911	Office Furniture & Equipment	252.52		119228 0145		
			07/31/01	1.1010.3911	Office Furniture & Equipment		252.52	119228 0145		
			07/31/01	1.1080.3911	Office Furniture & Equipment	168.87		119228 0135		
			07/31/01	1.1010.3911	Office Furniture & Equipment		168.87	119228 0135		
			07/31/01	1.1080.3911	Office Furniture & Equipment	168.87		119228 0135		
			07/31/01	1.1010.3911	Office Furniture & Equipment		168.87	119228 0135		
			07/31/01	1.1080.3911	Office Furniture & Equipment	699.42		119228 0125		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3911	Office Furniture & Equipment		699.42	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,059.93		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,059.93	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	885.13		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		885.13	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	531.08		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		531.08	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	755.40		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		755.40	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	572.16		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		572.16	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	14,042.05		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		14,042.05	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	30,820.59		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		30,820.59	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	4,695.34		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		4,695.34	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	4,128.56		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		4,128.56	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	8,704.53		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		8,704.53	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	31,648.56		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		31,648.56	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	141,059.09		119228 0127		
			07/31/01	1.1010.3911	Office Furniture & Equipment		141,059.09	119228 0127		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,413.33		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,413.33	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	7,339.37		119228 0139		
			07/31/01	1.1010.3911	Office Furniture & Equipment		7,339.37	119228 0139		
			07/31/01	1.1080.3911	Office Furniture & Equipment	7,339.37		119228 0139		
			07/31/01	1.1010.3911	Office Furniture & Equipment		7,339.37	119228 0139		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,654.07		119228 0139		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,654.07	119228 0139		
			07/31/01	1.1080.3911	Office Furniture & Equipment	648.31		119228 0139		
			07/31/01	1.1010.3911	Office Furniture & Equipment		648.31	119228 0139		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,714.04		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,714.04	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	50,874.90		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		50,874.90	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	910.27		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		910.27	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	4,798.68		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		4,798.68	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	62,881.37		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		62,881.37	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	3,064.74		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		3,064.74	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	7,027.68		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		7,027.68	119228 0126		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3911	Office Furniture & Equipment	7,027.68		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		7,027.68	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	7,027.66		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		7,027.66	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	7,027.66		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		7,027.66	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	7,229.42		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		7,229.42	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,086.33		119228 0133		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,086.33	119228 0133		
			07/31/01	1.1080.3911	Office Furniture & Equipment	471.98		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		471.98	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	574.84		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		574.84	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	653.53		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		653.53	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	587.61		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		587.61	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	4,552.24		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		4,552.24	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,749.52		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,749.52	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	2,313.54		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		2,313.54	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	4,824.46		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		4,824.46	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	97,002.60		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		97,002.60	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	54,272.68		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		54,272.68	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	3,777.88		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		3,777.88	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	3,502.35		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		3,502.35	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	3,021.30		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		3,021.30	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	166.10		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		166.10	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,569.19		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,569.19	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,038.70		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,038.70	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	550.51		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		550.51	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	541.71		119228 0129		
			07/31/01	1.1010.3911	Office Furniture & Equipment		541.71	119228 0129		
			07/31/01	1.1080.3911	Office Furniture & Equipment	557.08		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		557.08	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	557.09		119228 0125		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3911	Office Furniture & Equipment		557.09		119228 0125	
			07/31/01	1.1080.3911	Office Furniture & Equipment	4,053.44			119228 0125	
			07/31/01	1.1010.3911	Office Furniture & Equipment		4,053.44		119228 0125	
			07/31/01	1.1080.3911	Office Furniture & Equipment	2,494.88			119228 0126	
			07/31/01	1.1010.3911	Office Furniture & Equipment		2,494.88		119228 0126	
			07/31/01	1.1080.3911	Office Furniture & Equipment	14,652.00			119228 0133	
			07/31/01	1.1010.3911	Office Furniture & Equipment		14,652.00		119228 0133	
			07/31/01	1.1080.3911	Office Furniture & Equipment	862.62			119228 0125	
			07/31/01	1.1010.3911	Office Furniture & Equipment		862.62		119228 0125	
			07/31/01	1.1080.3911	Office Furniture & Equipment	469.11			119228 0149	
			07/31/01	1.1010.3911	Office Furniture & Equipment		469.11		119228 0149	
			07/31/01	1.1080.3911	Office Furniture & Equipment	539.41			119228 0149	
			07/31/01	1.1010.3911	Office Furniture & Equipment		539.41		119228 0149	
			07/31/01	1.1080.3911	Office Furniture & Equipment	2,320.24			119228 0149	
			07/31/01	1.1010.3911	Office Furniture & Equipment		2,320.24		119228 0149	
			07/31/01	1.1080.3911	Office Furniture & Equipment	2,750.74			119228 0149	
			07/31/01	1.1010.3911	Office Furniture & Equipment		2,750.74		119228 0149	
			07/31/01	1.1080.3911	Office Furniture & Equipment	2,439.47			119228 0125	
			07/31/01	1.1010.3911	Office Furniture & Equipment		2,439.47		119228 0125	
			07/31/01	1.1080.3911	Office Furniture & Equipment	570.23			119228 0125	
			07/31/01	1.1010.3911	Office Furniture & Equipment		570.23		119228 0125	
			07/31/01	1.1080.3911	Office Furniture & Equipment	10,342.16			119228 0127	
			07/31/01	1.1010.3911	Office Furniture & Equipment		10,342.16		119228 0127	
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,210.98			119228 0129	
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,210.98		119228 0129	
			07/31/01	1.1080.3911	Office Furniture & Equipment	693.17			119228 0133	
			07/31/01	1.1010.3911	Office Furniture & Equipment		693.17		119228 0133	
			07/31/01	1.1080.3911	Office Furniture & Equipment	449.72			119228 0127	
			07/31/01	1.1010.3911	Office Furniture & Equipment		449.72		119228 0127	
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,007.44			119228 0129	
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,007.44		119228 0129	
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,586.31			119228 0133	
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,586.31		119228 0133	
			07/31/01	1.1080.3911	Office Furniture & Equipment	625.55			119228 0135	
			07/31/01	1.1010.3911	Office Furniture & Equipment		625.55		119228 0135	
			07/31/01	1.1080.3911	Office Furniture & Equipment	2,534.80			119228 0125	
			07/31/01	1.1010.3911	Office Furniture & Equipment		2,534.80		119228 0125	
			07/31/01	1.1080.3911	Office Furniture & Equipment	744.18			119228 0125	
			07/31/01	1.1010.3911	Office Furniture & Equipment		744.18		119228 0125	
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,460.80			119228 0127	
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,460.80		119228 0127	
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,152.09			119228 0129	
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,152.09		119228 0129	
			07/31/01	1.1080.3911	Office Furniture & Equipment	688.71			119228 0126	
			07/31/01	1.1010.3911	Office Furniture & Equipment		688.71		119228 0126	
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,918.74			119228 0127	
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,918.74		119228 0127	
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,146.35			119228 0129	
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,146.35		119228 0129	

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3911	Office Furniture & Equipment	774.73		119228 0135		
			07/31/01	1.1010.3911	Office Furniture & Equipment		774.73	119228 0135		
			07/31/01	1.1080.3911	Office Furniture & Equipment	492.78		119228 0133		
			07/31/01	1.1010.3911	Office Furniture & Equipment		492.78	119228 0133		
			07/31/01	1.1080.3911	Office Furniture & Equipment	372.13		119228 0127		
			07/31/01	1.1010.3911	Office Furniture & Equipment		372.13	119228 0127		
			07/31/01	1.1080.3911	Office Furniture & Equipment	1,218.00		119228 0129		
			07/31/01	1.1010.3911	Office Furniture & Equipment		1,218.00	119228 0129		
			07/31/01	1.1080.3911	Office Furniture & Equipment	484.08		119228 0133		
			07/31/01	1.1010.3911	Office Furniture & Equipment		484.08	119228 0133		
			07/31/01	1.1080.3911	Office Furniture & Equipment	190.00		119228 0135		
			07/31/01	1.1010.3911	Office Furniture & Equipment		190.00	119228 0135		
			07/31/01	1.1080.3911	Office Furniture & Equipment	2,534.80		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		2,534.80	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	674.41		119228 0125		
			07/31/01	1.1010.3911	Office Furniture & Equipment		674.41	119228 0125		
			07/31/01	1.1080.3911	Office Furniture & Equipment	819.28		119228 0135		
			07/31/01	1.1010.3911	Office Furniture & Equipment		819.28	119228 0135		
			07/31/01	1.1080.3911	Office Furniture & Equipment	6,583.33		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		6,583.33	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	3,970.66		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		3,970.66	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	4,235.67		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		4,235.67	119228 0126		
			07/31/01	1.1080.3911	Office Furniture & Equipment	4,235.67		119228 0126		
			07/31/01	1.1010.3911	Office Furniture & Equipment		4,235.67	119228 0126		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,102.79		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,102.79	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,102.78		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,102.78	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,232.07		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,232.07	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,232.07		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,232.07	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,969.17		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,969.17	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,969.20		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,969.20	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,899.69		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,899.69	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	5,883.67		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		5,883.67	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	617.28		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		617.28	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	745.86		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		745.86	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	623.50		119228 0244		

Company 1 Montana Dakota Utilities Co.
Tax ID 410423660
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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3913	Personal Computer Equipment		623.50	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	6,250.88		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		6,250.88	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	647.30		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		647.30	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	5,150.39		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		5,150.39	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	989.37		119258 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		989.37	119258 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	989.38		119258 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		989.38	119258 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,158.51		119228 0242		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,158.51	119228 0242		
			07/31/01	1.1080.3913	Personal Computer Equipment	5,128.45		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		5,128.45	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	989.38		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		989.38	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,930.69		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,930.69	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,930.69		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,930.69	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,230.65		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,230.65	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	647.30		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		647.30	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	506.48		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		506.48	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	506.48		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		506.48	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	6,748.70		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		6,748.70	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,055.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,055.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,055.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,055.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,055.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,055.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,055.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,055.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,055.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,055.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	507.56		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		507.56	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	507.56		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		507.56	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,055.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,055.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	507.56		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		507.56	119228 0244		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913	Personal Computer Equipment	865.82			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		865.82		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	865.83			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		865.83		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	469.66			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		469.66		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,618.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,618.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,618.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,618.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,618.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,618.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,618.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,618.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	881.01			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		881.01		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	881.01			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		881.01		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,714.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,714.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,714.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,714.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,714.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,714.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,714.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,714.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	1,714.39			119228 0240	
			07/31/01	1.1010.3913	Personal Computer Equipment		1,714.39		119228 0240	
			07/31/01	1.1080.3913	Personal Computer Equipment	461.96			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		461.96		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	461.96			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		461.96		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	461.96			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		461.96		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	461.96			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		461.96		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	461.96			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		461.96		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	461.96			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		461.96		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	370.03			119228 0244	
			07/31/01	1.1010.3913	Personal Computer Equipment		370.03		119228 0244	
			07/31/01	1.1080.3913	Personal Computer Equipment	6,307.43			119228 0246	

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3913	Personal Computer Equipment		6,307.43	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,747.01		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,747.01	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,747.01		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,747.01	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,747.01		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,747.01	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	392.62		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		392.62	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	392.62		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		392.62	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	392.62		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		392.62	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,942.29		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,942.29	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	389.24		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		389.24	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	389.24		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		389.24	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,942.30		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,942.30	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,942.30		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,942.30	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	389.24		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		389.24	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,748.92		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,748.92	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,319.17		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,319.17	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,587.97		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,587.97	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	629.47		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		629.47	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,451.82		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,451.82	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	629.47		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		629.47	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,209.83		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,209.83	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,200.47		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,200.47	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	749.91		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		749.91	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	749.90		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		749.90	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,021.59		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,021.59	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	700.89		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		700.89	119228 0244		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913	Personal Computer Equipment	3,035.40		119228 0250		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,035.40	119228 0250		
			07/31/01	1.1080.3913	Personal Computer Equipment	705.77		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		705.77	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	705.77		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		705.77	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	705.77		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		705.77	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,931.99		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,931.99	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	716.03		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		716.03	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,529.80		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,529.80	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	716.03		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		716.03	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	730.46		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		730.46	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	730.47		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		730.47	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,665.48		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,665.48	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,665.48		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,665.48	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,707.73		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,707.73	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,707.73		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,707.73	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	730.47		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		730.47	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	730.47		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		730.47	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	8,497.63		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		8,497.63	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	49,414.59		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		49,414.59	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	24,089.06		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		24,089.06	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	35,913.29		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		35,913.29	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	60,616.43		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		60,616.43	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	88,524.68		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		88,524.68	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	832.69		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		832.69	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	832.69		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		832.69	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,939.99		119228 0246		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3913	Personal Computer Equipment		4,939.99	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,572.63		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,572.63	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,609.81		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,609.81	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,609.81		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,609.81	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,609.80		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,609.80	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,609.81		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,609.81	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	695.68		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		695.68	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	695.68		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		695.68	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	695.68		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		695.68	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	695.68		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		695.68	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	574.72		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		574.72	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,295.13		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,295.13	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,893.03		119228 0256		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,893.03	119228 0256		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,802.66		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,802.66	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	505.65		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		505.65	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,303.72		117914 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,303.72	117914 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	504.30		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		504.30	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,840.40		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,840.40	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,840.39		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,840.39	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,840.39		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,840.39	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	502.74		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		502.74	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	502.74		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		502.74	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	502.75		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		502.75	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	502.43		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		502.43	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,795.95		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,795.95	119228 0240		

Company 1 Montana Dakota Utilities Co.
Tax ID 410423660
From 07/01/01 Thru 07/31/01

Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913	Personal Computer Equipment	2,018.00		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,018.00	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,017.99		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,017.99	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,017.99		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,017.99	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	2,017.99		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,017.99	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	704.99		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		704.99	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	704.98		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		704.98	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	704.98		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		704.98	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	704.98		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		704.98	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	505.66		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		505.66	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,797.60		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,797.60	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,871.69		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,871.69	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,871.69		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,871.69	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	502.49		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		502.49	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	502.49		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		502.49	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,748.71		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,748.71	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	504.03		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		504.03	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,792.95		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,792.95	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	504.00		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		504.00	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,786.70		118266 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,786.70	118266 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	430.20		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		430.20	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,664.86		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,664.86	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,664.86		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,664.86	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,664.86		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,664.86	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,664.86		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,664.86	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	8,671.80		119228 0240		

Company 1 Montana Dakota Utilities Co.
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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3913	Personal Computer Equipment		8,671.80	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	427.87		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		427.87	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	917.59		119228 0212		
			07/31/01	1.1010.3913	Personal Computer Equipment		917.59	119228 0212		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,117.55		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,117.55	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,653.76		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,653.76	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	282.64		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		282.64	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,799.19		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,799.19	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,529.25		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,529.25	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,532.93		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,532.93	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,532.92		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,532.92	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,532.93		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,532.93	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,532.93		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,532.93	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,532.93		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,532.93	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	284.40		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		284.40	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	284.40		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		284.40	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	284.40		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		284.40	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	284.40		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		284.40	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	284.40		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		284.40	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,764.93		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,764.93	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,625.23		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,625.23	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	284.40		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		284.40	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,949.77		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,949.77	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	282.53		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		282.53	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,934.16		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,934.16	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	284.40		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		284.40	119228 0244		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913	Personal Computer Equipment	4,946.63			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		4,946.63		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	284.40			119228	0244
			07/31/01	1.1010.3913	Personal Computer Equipment		284.40		119228	0244
			07/31/01	1.1080.3913	Personal Computer Equipment	3,726.20			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		3,726.20		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	1,854.02			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,854.02		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	1,854.02			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,854.02		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	1,854.02			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,854.02		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	255.61			119228	0244
			07/31/01	1.1010.3913	Personal Computer Equipment		255.61		119228	0244
			07/31/01	1.1080.3913	Personal Computer Equipment	255.63			119228	0244
			07/31/01	1.1010.3913	Personal Computer Equipment		255.63		119228	0244
			07/31/01	1.1080.3913	Personal Computer Equipment	255.63			119228	0244
			07/31/01	1.1010.3913	Personal Computer Equipment		255.63		119228	0244
			07/31/01	1.1080.3913	Personal Computer Equipment	1,779.39			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,779.39		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	1,779.39			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,779.39		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	1,779.40			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,779.40		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	286.19			119228	0244
			07/31/01	1.1010.3913	Personal Computer Equipment		286.19		119228	0244
			07/31/01	1.1080.3913	Personal Computer Equipment	286.19			119228	0244
			07/31/01	1.1010.3913	Personal Computer Equipment		286.19		119228	0244
			07/31/01	1.1080.3913	Personal Computer Equipment	286.19			119228	0244
			07/31/01	1.1010.3913	Personal Computer Equipment		286.19		119228	0244
			07/31/01	1.1080.3913	Personal Computer Equipment	3,673.92			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		3,673.92		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	293.39			119228	0244
			07/31/01	1.1010.3913	Personal Computer Equipment		293.39		119228	0244
			07/31/01	1.1080.3913	Personal Computer Equipment	3,512.85			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		3,512.85		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	3,512.85			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		3,512.85		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	1,503.99			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,503.99		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	1,503.99			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,503.99		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	4,304.24			119228	0246
			07/31/01	1.1010.3913	Personal Computer Equipment		4,304.24		119228	0246
			07/31/01	1.1080.3913	Personal Computer Equipment	9,418.73			119228	0246
			07/31/01	1.1010.3913	Personal Computer Equipment		9,418.73		119228	0246
			07/31/01	1.1080.3913	Personal Computer Equipment	1,946.16			119228	0240
			07/31/01	1.1010.3913	Personal Computer Equipment		1,946.16		119228	0240
			07/31/01	1.1080.3913	Personal Computer Equipment	315.77			119228	0244

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3913	Personal Computer Equipment		315.77	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,202.44		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,202.44	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	740.54		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		740.54	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	706.28		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		706.28	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,750.66		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,750.66	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	317.43		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		317.43	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,773.89		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,773.89	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,132.45		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,132.45	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,132.45		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,132.45	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,706.31		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,706.31	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	281.72		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		281.72	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	281.72		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		281.72	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	682.96		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		682.96	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,152.75		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,152.75	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,152.74		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,152.74	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,090.00		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,090.00	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,772.33		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,772.33	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	468.46		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		468.46	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,965.17		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,965.17	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,001.16		119228 0242		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,001.16	119228 0242		
			07/31/01	1.1080.3913	Personal Computer Equipment	293.40		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		293.40	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,570.08		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,570.08	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,255.89		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,255.89	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	379.62		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		379.62	119228 0244		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913	Personal Computer Equipment	2,625.05		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		2,625.05	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	468.46		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		468.46	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	5,145.54		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		5,145.54	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	269.16		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		269.16	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,644.77		119258 0256		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,644.77	119258 0256		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,869.16		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,869.16	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,539.20		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,539.20	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	245.30		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		245.30	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	245.30		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		245.30	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,986.03		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,986.03	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,517.89		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,517.89	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,521.16		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,521.16	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,521.18		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,521.18	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	259.46		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		259.46	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	259.46		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		259.46	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,525.05		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,525.05	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	259.45		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		259.45	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,593.05		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,593.05	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	258.69		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		258.69	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	258.69		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		258.69	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,960.15		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,960.15	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,045.78		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,045.78	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,440.69		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,440.69	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,050.95		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,050.95	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,050.95		119228 0240		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3913	Personal Computer Equipment		4,050.95	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,965.51		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,965.51	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	258.04		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		258.04	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	258.04		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		258.04	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	343.47		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		343.47	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	258.43		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		258.43	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	258.43		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		258.43	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	258.43		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		258.43	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,738.40		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,738.40	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,738.38		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,738.38	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,586.18		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,586.18	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,025.67		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,025.67	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	262.87		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		262.87	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,807.39		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,807.39	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,314.52		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,314.52	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	259.77		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		259.77	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,406.55		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,406.55	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	249.91		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		249.91	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,513.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,513.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,513.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,513.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,513.36		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,513.36	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,513.35		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,513.35	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	262.87		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		262.87	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	262.87		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		262.87	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	262.87		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		262.87	119228 0244		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913	Personal Computer Equipment	262.87		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		262.87	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,458.08		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,458.08	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	266.62		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		266.62	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,637.05		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,637.05	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	4,514.17		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		4,514.17	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	255.30		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		255.30	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	283.80		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		283.80	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	255.67		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		255.67	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,448.10		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,448.10	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,448.10		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,448.10	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,448.10		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,448.10	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	259.44		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		259.44	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	446.51		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		446.51	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	446.51		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		446.51	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	256.31		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		256.31	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,523.43		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,523.43	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,435.44		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,435.44	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	246.79		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		246.79	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	1,927.31		119228 0246		
			07/31/01	1.1010.3913	Personal Computer Equipment		1,927.31	119228 0246		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,527.33		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,527.33	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	249.65		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		249.65	119228 0244		
			07/31/01	1.1080.3913	Personal Computer Equipment	3,445.57		119228 0240		
			07/31/01	1.1010.3913	Personal Computer Equipment		3,445.57	119228 0240		
			07/31/01	1.1080.3913	Personal Computer Equipment	246.79		119228 0244		
			07/31/01	1.1010.3913	Personal Computer Equipment		246.79	119228 0244		
			07/31/01	1.1080.3915	Other Computer Equipment	3,346.85		119228 0214		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.3915	Other Computer Equipment		3,346.85	119228 0214		
			07/31/01	1.1080.3973	General Telephone Comm. Eq.	777.85		119228 0754		
			07/31/01	1.1010.3973	General Telephone Comm. Eq.		777.85	119228 0754		
			07/31/01	1.1080.3973	General Telephone Comm. Eq.	2,728.43		119228 0754		
			07/31/01	1.1010.3973	General Telephone Comm. Eq.		2,728.43	119228 0754		
			07/31/01	1.1080.3973	General Telephone Comm. Eq.	5,020.33		119228 0754		
			07/31/01	1.1010.3973	General Telephone Comm. Eq.		5,020.33	119228 0754		
			07/31/01	1.1080.3973	General Telephone Comm. Eq.	17,605.50		119228 0750		
			07/31/01	1.1010.3973	General Telephone Comm. Eq.		17,605.50	119228 0750		
			07/31/01	1.1080.3973	General Telephone Comm. Eq.	2,283.52		119228 0339		
			07/31/01	1.1010.3973	General Telephone Comm. Eq.		2,283.52	119228 0339		
			07/31/01	1.1080.3973	General Telephone Comm. Eq.	913.97		119228 0750		
			07/31/01	1.1010.3973	General Telephone Comm. Eq.		913.97	119228 0750		
			07/31/01	1.1080.3978	Network Equipment	1,395.30		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		1,395.30	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	1,395.30		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		1,395.30	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	616.05		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		616.05	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	616.05		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		616.05	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	1,477.19		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		1,477.19	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	1,477.19		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		1,477.19	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	809.13		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		809.13	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	1,783.14		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		1,783.14	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	1,096.78		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		1,096.78	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	1,783.15		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		1,783.15	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	1,096.78		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		1,096.78	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	14,649.08		119228 0812		
			07/31/01	1.1010.3978	Network Equipment		14,649.08	119228 0812		
			07/31/01	1.1080.3978	Network Equipment	17,758.47		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		17,758.47	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	10,000.95		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		10,000.95	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	3,632.69		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		3,632.69	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	2,043.39		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		2,043.39	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	10,885.27		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		10,885.27	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	1,791.48		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		1,791.48	119228 0816		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3978	Network Equipment	3,292.13		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		3,292.13	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	3,632.69		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		3,632.69	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	2,838.03		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		2,838.03	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	3,973.26		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		3,973.26	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	697.18		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		697.18	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	697.18		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		697.18	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	10,565.35		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		10,565.35	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	3,973.26		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		3,973.26	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	58,259.45		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		58,259.45	119228 0816		
			07/31/01	1.1080.3978	Network Equipment	8,443.72		119228 0816		
			07/31/01	1.1010.3978	Network Equipment		8,443.72	119228 0816		
			07/31/01	1.1080.398	Miscellaneous Equipment	495.95		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		495.95	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	495.95		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		495.95	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	1,165.80		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		1,165.80	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	2,331.62		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		2,331.62	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	525.71		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		525.71	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	525.71		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		525.71	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	7,786.92		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		7,786.92	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	2,202.54		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		2,202.54	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	9,183.14		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		9,183.14	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	5,033.39		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		5,033.39	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	6,786.65		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		6,786.65	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	8,392.24		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		8,392.24	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	8,739.30		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		8,739.30	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	4,616.87		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		4,616.87	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	1,922.02		119228 0900		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1010.398	Miscellaneous Equipment		1,922.02	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	7,781.62		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		7,781.62	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	748.79		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		748.79	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	1,148.37		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		1,148.37	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	615.29		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		615.29	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	434.26		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		434.26	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	14,891.35		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		14,891.35	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	5,743.05		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		5,743.05	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	5,415.65		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		5,415.65	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	2,081.16		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		2,081.16	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	1,969.32		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		1,969.32	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	1,657.34		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		1,657.34	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	958.50		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		958.50	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	5,551.48		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		5,551.48	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	1,776.89		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		1,776.89	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	16,837.90		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		16,837.90	119228 0900		
			07/31/01	1.1080.398	Miscellaneous Equipment	2,361.60		119228 0900		
			07/31/01	1.1010.398	Miscellaneous Equipment		2,361.60	119228 0900		
					Montana Dakota Utilities Co.	5,491,489.97	5,491,489.97			
						5,491,489.97	5,491,489.97			
AD	540429	00001	07/31/01	J119228.0999.89	RWIP Clearing	4,593,548.51				
			07/31/01	1.1110.303CS	Misc. Intgble Plt-Cash Salvg		4,022.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.4211	Gain on Disp. of Property		169,438.01	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		14,823.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		55,458.33	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		20,344.51	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		5,092.01	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		4,531.34	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		1,487.65	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		18,937.87	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.390CS	Structures-Cash Salvage		34,057.22	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		6,468.23	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		20,863.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		25,056.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		1,244.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		1,680.92	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		9,666.98	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		58,836.67	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		55,524.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		676,996.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		223,010.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		22,032.22	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		17,107.14	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		45,374.46	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		103,652.43	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		4,865.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		17,875.55	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		11,367.21	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		6,724.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		9,897.93	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		120,261.62	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		2,241.52	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		13,172.60	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		12,697.28	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		26,956.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		78,265.09	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		2,241.52	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		20,925.78	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		116,183.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		7,127.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		29,838.70	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		82,236.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		3,474.12	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		810.22	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		12,375.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		81,564.48	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		85,042.01	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		109,377.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		53,458.55	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		176,334.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		12,684.03	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		1,282.16	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		4,543.89	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		1,929.55	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		14,106.76	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		34,806.75	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		18,416.76	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		47,214.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		2,024.74	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.390CS	Structures-Cash Salvage		12,910.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		11,736.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		17,393.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		229.08	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		24,339.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		19,919.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		784.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		44,795.56	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		28,670.92	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		4,239.61	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		2,413.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		101,835.51	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		319.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		107,374.79	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		2,821.77	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		530.65	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.390CS	Structures-Cash Salvage		4,031.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		787.95	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		787.95	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		661.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		661.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		200.95	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		200.95	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		583.87	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		671.25	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		489.65	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		553.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		348.18	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		669.75	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		884.52	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		884.52	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		200.95	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		489.65	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		489.65	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		576.63	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		262.09	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		43,110.57	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		5,735.53	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		222.16	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		3,505.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		9,283.63	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		749.59	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		460.33	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		529.82	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		555.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		555.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		555.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		600.84	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		887.76	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		555.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		600.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		600.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		600.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		413.48	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		600.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		474.86	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		446.22	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		381.39	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		558.67	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		493.24	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		229.28	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		499.19	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		229.44	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		152.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		152.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		643.61	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		975.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		814.20	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		491.06	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		715.24	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		556.61	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		542.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		13,314.25	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		29,223.87	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		4,451.92	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		3,914.24	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		8,253.63	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		30,009.30	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		133,745.41	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,343.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		7,022.93	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		7,022.93	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,584.53	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,603.65	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		620.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,644.08	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		30,257.92	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		843.45	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		4,372.07	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		58,315.56	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,839.46	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		6,776.57	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		6,776.57	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		6,776.55	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		6,776.55	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		6,997.56	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,051.35	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		457.41	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		559.20	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		636.40	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		575.14	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		4,456.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,714.86	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,273.58	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		4,741.16	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		95,430.24	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		53,392.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		3,717.17	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		3,446.18	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,972.74	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		163.42	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,543.98	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,021.93	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		542.98	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		535.07	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		550.12	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		550.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		4,003.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,467.10	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		14,525.50	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		855.07	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		465.06	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		534.78	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,300.16	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,726.95	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,421.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		566.01	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		10,303.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,206.48	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		690.56	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		448.07	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,003.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,580.43	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		623.24	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,525.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		741.48	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,455.37	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,147.83	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		686.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,911.63	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,142.09	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		771.82	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		490.92	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		370.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		1,213.44	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		482.25	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		189.28	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		2,525.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		673.58	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		819.28	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		6,583.33	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		3,970.66	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		3,970.66	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		4,235.67	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3911CS	Office F & E-Cash Salvage		4,235.67	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		871.81	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		871.80	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		345.90	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		345.90	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		834.46	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		834.49	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		815.53	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		393.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		295.45	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,654.12	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		173.61	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		225.52	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		207.74	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,096.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		215.76	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,984.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		380.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		380.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		446.45	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,976.31	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		380.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,515.17	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,515.17	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		859.36	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		249.46	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		194.96	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		194.96	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,741.60	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		834.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		834.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		834.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		834.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		834.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		206.00	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		206.00	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		834.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		206.00	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		378.20	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		378.21	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		205.54	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		707.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		707.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		707.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		707.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		384.96	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		384.96	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		803.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		803.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		803.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		803.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		803.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		803.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		803.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		216.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		216.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		216.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		216.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		216.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		216.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		216.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,073.50	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		172.42	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,959.37	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		851.77	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		851.77	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		851.77	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		191.00	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		191.00	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		191.00	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		947.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		189.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		189.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		947.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		947.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		189.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		853.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,159.41	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,324.52	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		321.45	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,281.63	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		321.45	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,173.91	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,168.95	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		398.22	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		398.21	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,131.70	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		372.12	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,675.76	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		397.13	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		397.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		397.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,294.15	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		417.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,475.36	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		417.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		426.07	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		426.08	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,723.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,723.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,305.48	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,795.08	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,795.08	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		433.26	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		433.26	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal	3,452.40		119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal	18,514.17		119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal	4,770.51		119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal	5,925.38		119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal	711.44		119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		12,010.66	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		511.83	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		511.83	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,036.19	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,580.44	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,022.96	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,022.95	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,022.96	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		441.87	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		441.87	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		441.87	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		441.87	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		388.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,230.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,366.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,693.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		358.09	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,340.01	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		357.02	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,322.63	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,322.62	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,322.62	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		361.26	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		361.26	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		361.27	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		361.01	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,728.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,450.28	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,450.27	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,450.27	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,450.27	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		506.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		506.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		506.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		506.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		368.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,310.60	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,822.91	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,822.91	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		366.31	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		366.31	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,772.40	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		372.65	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,805.01	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		372.62	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,839.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		322.56	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,283.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,283.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,283.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,283.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		6,774.57	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		334.06	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		716.62	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,768.06	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,533.23	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,341.68	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		229.78	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,126.39	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,258.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,980.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,980.68	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,980.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,980.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,980.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		239.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		239.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		239.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		239.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		239.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,489.02	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,902.41	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		239.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,645.06	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		238.49	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,652.08	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		242.84	119228 CASH SALV FROM CHCC		

Company 1 Montana Dakota Utilities Co.
Tax ID 410423660
From 07/01/01 Thru 07/31/01

Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		4,243.26	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		242.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,182.80	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,602.81	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,602.81	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,602.81	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		220.91	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		220.93	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		220.93	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,538.43	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,538.43	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,538.44	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		247.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		247.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		247.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,176.23	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		253.50	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,110.31	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,110.31	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,331.50	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,331.50	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,766.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		8,339.58	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,702.80	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		276.17	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,835.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		647.96	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		617.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,568.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		284.29	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,380.59	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,831.10	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,831.10	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,436.03	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		261.15	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		261.15	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		261.15	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		619.21	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,044.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,044.68	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,012.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,643.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		434.30	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,676.63	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		959.40	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		278.00	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,488.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		4,078.49	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		363.70	119228 CASH SALV FROM CHCC		

Company 1 Montana Dakota Utilities Co.
Tax ID 410423660
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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		2,522.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		448.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		4,985.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		260.79	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		4,499.57	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,753.53	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,491.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		237.62	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		237.62	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,936.44	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,409.79	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,474.33	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,474.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		251.33	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		251.33	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,478.16	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		251.32	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,546.77	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		250.56	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		250.56	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,838.50	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,921.13	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,395.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,926.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,926.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,882.87	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		249.91	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		249.91	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		293.17	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		250.30	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		250.30	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		250.30	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,686.11	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,686.09	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,474.10	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,941.77	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		257.39	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,769.78	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,245.41	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		254.44	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,377.25	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		244.69	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,481.80	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,481.80	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,481.80	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,481.79	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		257.39	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		257.39	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		257.39	119228 CASH SALV FROM CHCC		

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Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		257.39	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,386.06	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		261.08	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,563.29	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		4,422.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		249.96	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		277.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		250.33	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,433.02	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,433.02	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,433.02	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		256.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		256.73	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		441.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		441.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		253.64	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,523.43	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,435.44	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		246.79	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		1,927.31	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,527.33	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		249.65	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		3,445.57	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3913CS	Personal Comp Equip-Cash Sal		246.79	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3915CS	Other Computer Equipment		3,149.84	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3973CS	General Telephone-Cash Salvg		352.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3973CS	General Telephone-Cash Salvg		1,568.81	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3973CS	General Telephone-Cash Salvg		3,153.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		2,341.88	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3973CS	General Telephone-Cash Salvg		11,113.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3973CS	General Telephone-Cash Salvg		2,040.82	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3973CS	General Telephone-Cash Salvg		865.37	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		2,864.18	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		418.89	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		418.89	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		418.89	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		392.25	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		392.25	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		172.98	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		172.98	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		423.16	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		423.16	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		328.44	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		1,002.78	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		616.78	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		1,002.79	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		616.78	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		8,239.70	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		16,450.87	119228 CASH SALV FROM CHCC		

Company 1 Montana Dakota Utilities Co.
Tax ID 410423660
From 07/01/01 Thru 07/31/01

Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		9,264.90	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		3,367.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		1,894.31	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		10,083.91	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		1,660.80	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		3,051.90	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		3,367.85	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		2,631.04	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		3,683.60	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		646.29	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		646.29	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		9,787.29	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		3,683.60	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		53,972.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.3978CS	Sprvsry & Tele-Cash Salvage		7,818.72	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		426.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		426.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		1,003.02	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		2,006.66	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		451.67	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		451.67	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		6,750.08	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		1,904.61	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		7,942.19	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		4,527.47	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		6,104.99	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		7,567.10	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		7,976.70	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		4,215.94	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		1,752.90	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		7,103.43	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		683.12	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		1,047.27	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		554.06	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		391.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		14,453.81	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		5,574.91	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		5,336.34	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		2,050.71	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		1,944.60	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		1,643.38	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		950.46	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		5,506.35	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		1,762.05	119228 CASH SALV FROM CHCC		
			07/31/01	1.1080.398CS	Misc Equip-Cash Salvage		16,697.69	119228 CASH SALV FROM CHCC		
					Montana Dakota Utilities Co.	4,626,922.41	4,626,922.41			
						4,626,922.41	4,626,922.41			

Company 1 Montana Dakota Utilities Co.
Tax ID 410423660
From 07/01/01 Thru 07/31/01

Ty	Document Number	Co	G/L Date	Account Number	Description	Debit Amount	Credit Amount	Explanation	Address Number	Name
				Grand Total		10,118,412.38	10,118,412.38			

KNUDSON APPRAISAL SERVICE

BILL KNUDSON, IFA

July 28, 2001

Mr. Alvin J. Feist
MDU Resources Group, Inc.
PO Box 5650
Bismarck, ND 58502

Dear Mr. Feist:

At your request I have made an appraisal of the fee simple estate of a real property known as the Schuchart Office Building located at 918 East Divide Avenue in Bismarck, North Dakota. The property is owner occupied and thus there is no leasehold interest or leased fee estate to considered. The purpose of this appraisal is to determine the market value of the fee simple estate for financing purposes. Market value is defined as the most probable price which a property should bring in a competitive and open market under all conditions requisite to a fair sale, the buyer and seller, each acting prudently and knowledgeably and assuming the price is not affected by undue stimulus. Implicit in this definition is the consummation of a sale as of a specified date and the passing of the title from the seller to the buyer.

I have personally inspected the property. I have considered similar properties in the area in order to determine the value by comparison to other properties which have sold in the marketplace. The market value of subject property "As Is" as of July 3, 2001 is $2,700,000.00. **Departure from the Uniform Standard of Professional Appraisal Practice was not taken. This is considered to be a complete appraisal in summary format and meets the USPAP. There is no personal property included in the appraised value.**

Following in report form are definitions, limiting conditions, comparable sales data, maps, photographs and the qualifications of the appraiser. It has been a pleasure working on this on your behalf. If you have any questions or further requirements, please give me a call.

Respectfully,

Bill A. Knudson, IFA
CG-1031--ND
Expires: 1/1/02

BAK/kab

1894 Bonn Blvd Bismarck, North Dakota 58504 701-258-3637 (FAX: 701-255-9045)

MONTANA-DAKOTA UTILITIES CO.
LATE FILED EXHIBITS
CASE NO. PU-399-02-183

Late Filed Exhibit 4

Provide the cost of the 1991 depreciation study, the cost of supporting the 1991 study in this proceeding and a copy of all correspondence and the contract with AUS Consultants for preparation of the new depreciation study.

Response:

The cost of the 1991 depreciation study performed by Stone & Webster was $97,461.10. The cost covered complete studies for electric, gas and common plant. A breakdown by category is not available.

The cost incurred by Montana-Dakota in addressing the depreciation recommendation of Mr. Majoros on behalf of the Staff was $31,900 through the conclusion of the hearing on October 8.

Please see Attachment A for a copy of correspondence with AUS regarding depreciation studies. The remaining correspondence, which was accomplished by email, is no longer available as it was deleted from the system in the normal course of cleaning up old files. There is no written contract for the new depreciation study.

Bienek, Paul

From: Earl M. Robinson [erobinson@wfw-

Sent: Friday, May 31, 2002 8:47 AM

To: Bienek, Paul

Subject: GPNG & MDU Depreciation Studies

Paul,

This e-mail confirms the information that we discussed during our telephone conversation of last evening. I acknowledge that our target date for completing the Great Plains Natural Gas depreciation study is July 31, 2002. Conversely, it was our initial goal of completing the Montana Dakota Utilities Co - Gas & Common deprecation studies as of early September, 2002, however, you indicated that the time line for completing those study drafts are likely to be extended to some time in November, Certainly the extended amount of time will be welcome to you as well as us, given that I will be physically out of the office during late September and early October.

With regard to cost it is estimated that the Great Plains Natural Gas depreciation study will aggregate in the range of $23,000-$25,000 plus reimbursement of out of pocket costs for travel and living expenses, postage, etc. Conversely for the Montana-Dakota Utilities Co-Gas depreciation study the aggregate cost for the study is estimated at $35,000 plus out of pocket cost. One item that we did not discuss during our conversation was the cost of the Common Plant depreciation study which I estimate would aggregate in the range of $9,000-$11,000 plus out of pocket cost.

Finally, as discussed during our telephone conversation, attached is an initial data request listing the data requirements for completing the depreciation studies. In addition to the data request also attached is a data template and data request memo that provides additional notes and discussions related to the data request.

If you have any questions, wish to discuss any of the items, or need assistance in any way please do not hesitate to call.

I would like to thank you for the opportunity to provide this service to your company, and look forward to long term relationship with you and your associates.

Earl

MONTANA-DAKOTA UTILITIES CO.
LATE FILED EXHIBITS
CASE NO. PU-399-02-183

Late Filed Exhibit 5

Provide the workpaper showing the other O&M expense versus inflation since 1996.

Response:

Please see Attachment A for the workpaper showing the percentage change in O&M items not adjusted individually versus the change in the CPI for the years 1996-2001.

MONTANA-DAKOTA UTILITIES CO.
ALL OTHER EXPENSE
GAS UTILITY - NORTH DAKOTA
1996-2001

	1996	1997	1998	1999	2000	2001
O&M Not Adj. Individually 1/						
Gas Supply	$80,507	$76,405	$77,669	$70,570	$73,036	$73,998
Distribution	685,964	503,371	674,738	794,750	829,692	920,786
Customer Acct.	622,388	652,268	639,733	700,174	813,771	981,430
Customer Svs.	4,651	5,114	8,625	10,474	13,486	15,465
Sales	71,474	69,632	53,310	71,851	79,592	81,077
A&G	1,108,199	1,093,424	1,162,458	1,249,136	1,371,387	1,614,995
Total	$2,573,183	$2,400,214	$2,616,533	$2,896,955	$3,180,964	$3,687,751
% Change						
Gas Supply		-5.10%	1.65%	-9.14%	3.49%	1.32%
Distribution		-26.62%	34.04%	17.79%	4.40%	10.98%
Customer Acct.		4.80%	-1.92%	9.45%	16.22%	20.60%
Customer Svs.		9.95%	68.65%	21.44%	28.76%	14.67%
Sales		-2.58%	-23.44%	34.78%	10.77%	1.87%
A&G		-1.33%	6.31%	7.46%	9.79%	17.76%
Total		-6.72%	9.01%	10.72%	9.80%	15.93%
Cumulative Change in O&M		**-6.72%**	**1.68%**	**12.58%**	**23.62%**	**43.31%**
CPI - Average	156.9	160.5	163.0	166.6	172.2	177.1
Change in CPI		2.29%	1.56%	2.21%	3.36%	2.85%
Cumulative Change in CPI		**2.29%**	**3.89%**	**6.18%**	**9.75%**	**12.87%**

1/ Total O&M less labor, benefits, insurance, advertising and regulatory commission expense.

MONTANA-DAKOTA UTILITIES CO.
LATE FILED EXHIBITS
CASE NO. PU-399-02-183

Late Filed Exhibit 6

Provide the details of labor and bonuses for 2000 through 2003.

Response:

Please see Attachment A.

MONTANA-DAKOTA UTILITIES CO.
LABOR EXPENSE
GAS UTILITY
2000-PROJECTED 2003

	2000 1/	2001	Projected (Plan) 2002	Projected 2003
5110 - Straight Time	$15,708,980	$16,999,175	$20,717,405	$21,338,927
5120 - Premium Time	640,161	715,136	622,716	641,397
5130 - Bonuses	1,035,621	1,846,822	1,039,398	
5140 - Moving Allowance	14,198	44,067	32,233	33,200
5150 - Meals	20,439	24,649	26,376	27,167
5193 - Vacation	2,184,225	2,382,176		0
Total	$19,603,624	$22,012,026	$22,438,128	$22,040,691
Total Excluding Bonus	$18,568,003	$20,165,204	$21,398,730	$22,040,691
3 year average bonus	1,307,280	1,307,280	1,307,280	1,346,498
with 3 year average bonus	$19,875,283	$21,472,484	$22,706,010	$23,387,189
Prior year			$22,012,026	$22,706,010
% Increase			3.15%	3.00%

1/ Includes only six months of Great Plains.

Scott, Sandi L.

From: Bauske, Shelly A.
Sent: Tuesday, October 15, 2002 12:41 PM
To: Scott, Sandi L.
Subject: FW: Money Received.....

-----Original Message-----
From: **Geiger, Gloria A.**
Sent: Tuesday, October 15, 2002 12:40 PM
To: Bauske, Shelly A.
Cc: Geiger, Gloria A.
Subject: RE: Money Received.....

7700 8503 248 22183

Gloria Geiger
North Dakota Public Service Commission
600 E Boulevard 13th Floor Dept 408
Bismarck, ND 58505-0480
701-328-2401
fax 701-328-2133
gag@psc.state.nd.us

-----Original Message-----
From: **Bauske, Shelly A.**
Sent: Tuesday, October 15, 2002 11:21 AM
To: Geiger, Gloria A.
Subject: Money Received.....

Case No. PU-399-02-183
MDU
$12,808.02

63 **PU-399-02-183** Pages: 0

$12,808.02 received

by Montana-Dakota Utilities Co., a Division of MDU Re

10/15/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

OFFICE OF ADMINISTRATIVE HEARINGS

STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state.nd.us
www.state.nd.us/oah

October 14, 2002

RECEIVED
OCT 15 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

William W. Binek
Hearing Administrator
Public Service Commission
600 E. Boulevard Avenue - Dept. 408
Bismarck, ND 58505

Dear Mr. Binek:

On October 7 and 8, 2002, I presided as a procedural administrative law judge in the matter of MDU Natural Gas Rate Increase Application - PU-399-02-183. The hearing is closed. Accordingly, I am closing our file on this matter and returning that portion of the record I have in my possession to you. Please find enclosed copies of documents that have been transmitted to us, as well as originals and copies of documents received while the file was in our possession, for filing with the official agency record of this matter. The court reporter has the original exhibits because she is preparing a transcript.

I have also included an exhibit list for the file that documents all of the 37 exhibits that were admitted as evidence and the four documents that were made a part of the record on official notice by the commission (hearing examiner).

Thank you for your attention to this matter.

Sincerely,

Allen C. Hoberg
Administrative Law Judge

ACH/ljc

Encl.

cc: Mr. Don Ball, MDU

62 **PU-399-02-183** Pages: 1

Letter closing ALJ's file

by Office of Administrative Hearings by Allen Hoberg, /

10/15/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

RECEIVED
OCT 15 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

EXHIBIT LIST

Matter	Montana Dakota Utilities Co. - Rate Increase Application - PU-399-02-183 Before the North Dakota Public Service Commission
Hearing	October 7 and 8, 2002 - PSC hearing room "M" = MDU "S" = PSC staff "A" = admitted "NA" = not admitted "ON" = Official Notice taken by Commission

No.	Description	Mkd	Idd	Ofd	W/D	Adm	Note
1	MDU Application			M		A	Docket No. 3
2	Statements A-O			M		A	Docket No. 2
3	Direct testimony C. Wayne Fox			M		A	Exhibits 3-9 were submitted en masse in one blue binder but individually marked and offered
4	Direct testimony of J. Steven Gaske			M		A	
5	Direct testimony of Craig A. Keller			M		A	
6	Direct testimony of Rita A. Mulkern			M		A	
7	Direct testimony of Richard A. Espeland			M		A	
8	Direct testimony of Russell A. Feingold			M		A	
9	Direct testimony of Tamie A. Aberle			M		A	
10	September 3, 2002 Mike Diller memo			S		A	
11	Securities and Exchange Com doc re Keyspan Corp			S		A	
12	Response of C.W. King - September 6, 2002 Data Request			S		A	

13	Public Utilities Reports Advance Sheets December 15, 2001			S		A	
14	MDU Resources Group, Inc. $150,000 note - prospectus			S		A	
15	Direct testimony of Charles W. King			S		A	Docket No. 48
16	MDU - Working Capital, Dec 2000 - Dec 2001			S		A	
17	Electric & Gas Utilities percent regulated revenue			S		A	
18	Value Line information on selected companies			M		A	
19	Direct Testimony of Michael J. Majoros, Jr.			S		A	Docket No. 49
20	Direct testimony of Majoros - Page 6 Table expanded			S		A	
21	C. King data request no. 21			S		A	
22	Rebuttal testimony of John Jeter - MDU			M		A	Docket No. 54
23	Rebuttal testimony of Craig Keller - MDU			M		A	Docket No. 57
24	Rebuttal testimony of J. Steven Gaske - MDU			M		A	Docket No. 58
25	Rebuttal testimony of Rita Mulkern - MDU			M		A	Docket No. 53
26	Rebuttal testimony of Tamie Aberle - MDU			M		A	Docket No. 52

27	Rebuttal testimony of Richard D. Spratt - MDU			M		A	Docket No. 56
28	Rebuttal testimony of Richard Espeland - MDU			M		A	Docket No. 55
29	MDU Summary of Exhibit (MJM-7)			M		A	
30	MDU Summary of Negative Salvage for Services 1995-2001			M		A	
31	Effects of a Flotation Cost Adjustment			M		A	
32	Alternative Proxy Groups			M		A	
33	Summary of DCF Studies			M		A	
34	Ibbotson Historical Returns			M		A	
35	Natural Gas Furnaces - from webpage			M		A	
36	Bond Yields of Mr. King's Proxy Group and MDU Resources/ MDU Bonds			M		A	
37	MDU Gas Utility - ND Rate 60 Bill Comparison Residential Gas Service			M		A	
ON	April 24, 2002, FOF, COL, Order PU -399-01-186			S			ON in lieu of request for admission as exhibit
ON	Three cases - Re Yankee Gas Services Company; Re Berkshire Gas Company; Re Atlanta Gas Light Company			S			ON in lieu of request for admission as exhibits - objection by MDU

APPROVED
DATE: 10-10-02
KMF

Admin
Al.

MOTION

October 10, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission bill Montana-Dakota Utilities Co. for costs incurred to date in Case No. PU-399-02-183, Montana-Dakota Utilities Co., Natural Gas Rate Increase, Application.

60 **PU-399-02-183** Pages: 3

Utility Valuation Motion/Letter/Billing Statement
by Public Service Commission

10/10/2002 CC: Comm Legal PUD (3) Mike ALJ .

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

October 10, 2002

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

RE: Case No. PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the October 10, 2002 Public Service Commission meeting for the expenses incurred to date in Case No. PU-399-02-183.

Under N.D.C.C. 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Administrative Staff Officer
701-328-2401

Enc.

Billing Statement

October 10, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

Expenses Incurred to Date:

Consultant	$11,827.96
Advertising Costs	618.21
Meeting Costs	200.85
Travel	109.94
Postage	26.49
Office of Administrative Hearings	24.57

Amount Due:

Montana-Dakota Utilities Co.	$12,808.02

Send Payment and a Copy of this Statement To:

Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

September 24, 2002

RECEIVED
SEP 24 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505

Re: General Natural Gas Rate Application
Case No. PU-399-02-183

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. herewith submits the original and seven (7) copies of the rebuttal testimony of Dr. J. Stephen Gaske, Mr. Craig A. Keller, Mr. Richard D. Spratt, Mr. Richard A. Espeland, Mr. John A. Jeter, Ms. Rita A. Mulkern and Ms. Tamie A. Aberle.

Two (2) copies of the rebuttal testimony have been mailed to Snavely King Majoros O'Conner & Lee, Inc., 1220 L St NW, Suite 410, Washington, DC 20005.

Please acknowledge receipt by stamping or initiating the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball

Donald R. Ball
Director of Regulatory Affairs

Attachment
cc: C.W. Fox
D.W. Schulz
W.P. Pearce

59 PU-399-02-183 Pages 1
Cover letter re rebuttal testimony
by Montana-Dakota Utilities Co., a Division of MDU Re
09/24/2002 CC: Comm Legal PUD (3) Mike ALJ

Exhibit No.___(JSG-3)

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-399-02-183

PREPARED REBUTTAL TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am President of Zinder Companies, Inc., 7720 Wisconsin Avenue, Suite B-102 Bethesda, MD 20814.

Q2. Are you the same J. Stephen Gaske who filed Prepared Direct Testimony earlier in this proceeding?

A. Yes.

Q3. What is the purpose of your Prepared Rebuttal Testimony?

A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to evaluate the Direct Testimony of Charles W. King filed on behalf of the Staff of the North Dakota Public Service Commission ("PSC") on August 30, 2002. In his testimony, Mr. King makes a number of errors in analysis that lead him to recommend an inadequate allowed rate of return for setting Montana-Dakota's North Dakota gas distribution rates. Consequently, I will respond to various issues addressed in Mr. King's testimony including: the need for a flotation cost adjustment, the incorporation of growth rate data in the estimate, the dividend yield adjustment to the DCF model, the relevance of the Risk Premium and Alternative

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Equity Investment analyses in my Prepared Direct testimony, the selection of a proxy group, and the risk implications of being a diversified, regulated company.

Flotation Cost

Q4. At page 28, lines 1-5 of his testimony, Mr. King claims that Montana-Dakota's costs of raising new common equity capital are 0.1 percent. Do you agree with his analysis and conclusion?

A. No. Mr. King has made a classic "apples-to-oranges" comparison in attempting to calculate the flotation costs that Montana-Dakota would incur if it needed to attract any significant amount of new common equity capital in order to finance its gas distribution utility operations. Mr. King's analysis looks at the issuance costs that Montana-Dakota has incurred since 1997 to conclude that the costs of *issuing* new common equity are relatively low. However, the real test of a reasonable allowed return is whether it is sufficient to attract new capital for investment in the regulated operation on reasonable terms. Mr. King's analysis does not address that issue.

Q5. Is Mr. King correct in saying on page 28, line 2, that "(f)lotation costs are incurred only when a company issues new stock?"

A. Yes. However, his observations and conclusions on this issue are off point as he seems to misunderstand the primary reason why a flotation cost adjustment is required. The Supreme Court established the "Capital Attraction" standard as one test of a reasonable allowed rate of return. For example, in *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> *"The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and **enable** it to raise the money necessary for the proper discharge of its public duties."*[1]

Similarly, in *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 603 (1944))* the Court described the relevant criteria as follows:

> *"From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... That return, **moreover**, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."*[2]

The Court's requirement that the allowed return must "enable" a company to raise capital does not mean that the company must raise capital within some specified time period. Instead, it means that the company must have in place the ability to attract capital so that it can exercise that ability if and when required. By its use of the word "moreover" the Court made it clear that an allowed return is not sufficient if it merely allows the company to meet its current financial obligations. Instead, an additional and overriding requirement is that the return also must be sufficient to assure that the company can attract capital and maintain its financial integrity. Because flotation costs are the additional component of capital costs that apply above and beyond the return required to service current capital needs, an allowance for flotation costs is required in order to meet the "Capital Attraction" standard.

[1] Emphasis added.
[2] Emphasis added.

Q6. What is the difference between the "Capital Attraction" standard and Mr. King's approach?

The Capital Attraction standard requires that the allowed rate of return must be sufficient to allow the regulated company to raise capital by issuing new common stock on reasonable terms. This standard applies to companies that are not planning to issue new common stock, as well as to those that are planning to issue such stock. This "yardstick" established by the Court poses a hypothetical stock issue as a means for measuring the reasonableness of the allowed rate of return: *if* the allowed rate of return is sufficient to allow the company to raise new capital on reasonable terms, *then* the rate of return is legally adequate.

Mr. King and I are in agreement that flotation costs are incurred when a company must issue common stock to raise new capital. However, we are suggesting different standards for setting an allowed rate of return. I propose that the "Capital Attraction" standard be applied by recognizing that flotation costs must be incurred if the company needs to issue new common stock in order to attract capital. In contrast, Mr. King is proposing an "Indifference" or "No-New Capital" standard. Without flotation costs, a correctly established DCF rate of return should make existing investors indifferent between (i) providing natural gas service to the public or (ii) paying out all cash flow as dividends and gradually liquidating the utility operation. Such a rate of return may be barely adequate to compensate capital that is already sunk in the utility, but it is inadequate to attract capital from any outside sources because it is not sufficient to compensate for the flotation costs associated with raising capital in the market. Thus, although Mr. King recognizes

that flotation costs are a cost of attracting new common equity capital, he does not recognize that the ability to attract new common equity capital, *i.e.* the "Capital Attraction" standard, is a key measure of the adequacy of an allowed rate of return for regulated companies.

Q7. What has been Montana-Dakota's cost of attracting new common equity capital for investment in its gas distribution operations in recent years?

A. Examination of the data cited by Mr. King on page 28, lines 7-11 and footnote 3, indicates the level of common stock flotation costs incurred by Montana-Dakota to attract new capital funds. The flotation cost associated with obtaining new common equity capital funds that could be invested in rate base was 3.43 percent, computed as follows:

Amount Raised	$157,411,736
Flotation Cost	5,214,211
Net Funds Available	$152,197,525
Flotation Cost/Net Funds	3.43%

Thus, if one focuses on the portion of Mr. King's analysis that is relevant for estimating Montana-Dakota's cost of attracting new common equity capital for investment in its gas distribution utility operations, that past experience indicates a cost of 3.43 percent. Since the recent past experience of MDU Resources is close to the cost experienced by other gas distribution companies on some stock issuances, as shown on Exhibit No. ___(JSG-2), Schedule 3, it is clear that the flotation cost adjustment should be at least 3.43 percent. However, the experience of other gas distribution companies suggests that a flotation cost adjustment of 4.75 percent is required to ensure that the allowed rate of return is sufficient to attract capital on reasonable terms.

Q8. Is Mr. King correct when he suggests that the required flotation cost adjustment is 0.1 percent?

A. No. Mr. King's adjustment is not a cost of capital, expressed as a percentage of new capital raised. Instead, his proposed adjustment is based on the absolute amount of flotation costs incurred in the recent past, as a percent of the total capital of MDU Resources. In other words, if MDU Resources had issued large amounts of common stock recently, Mr. King would calculate a larger flotation cost adjustment. But, if MDU Resources had not issued common stock recently, Mr. King would have calculated no flotation cost adjustment.

This approach of Mr. King's misses the point of applying a flotation cost adjustment. Because flotation costs are a necessary component of the cost of attracting capital, a flotation cost adjustment is required in order for the allowed return to be sufficient to "assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." Financial integrity and the ability to attract capital are fundamental requirements that exist regardless of how much new capital a company has raised recently. Thus, the flotation cost adjustment required to attract capital cannot be measured based on the absolute amount of new capital the company has raised recently. Instead, the appropriate flotation cost adjustment should be measured as an estimated percentage of the amount of any new capital that the utility might need to attract, if the company were to have a need to attract new funds. Otherwise, the company would not be in a position to attract new common equity without impairing the financial integrity of existing stockholders' investment.

Q9. Is the need for a flotation cost adjustment to the rate of return widely recognized among economists as a required part of an allowed rate of return that will attract capital without diluting the value of existing investors' equity?

A. Yes. In commenting on the fair rate of return in his classic treatise on public utility ratemaking, Bonbright stated that:

> *"...book values (with allowances for the probable need to underprice new common-stock offering) should set a floor to the market values..."*

James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 249. Similarly, Myron Gordon, the man who is credited with having developed the DCF model for estimating rate of return, has stated that a regulatory agency should set the allowed rate of return greater than the investor return requirement so as to allow the firm to issue stock at a price that will yield net proceeds equal to book value. Professor Gordon advocates the following adjustment:

> *"The agency need only estimate the proportion that the proceeds per share on an issue bear to the price of the stock and adjust the allowed rate of return so that the price per share is the indicated ratio of the book value per share. If the proceeds on an issue are 91 percent of market price, the agency should maintain market price at about 110 percent of book value."*

Myron J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State University, 1974, pages 165-166. In order to meet this requirement, the flotation cost adjustment must be applied to the entire rate of return. The flotation cost adjustment that I have proposed attempts to meet the same standards advocated by these other economists.

Selection of Proxy Companies

Q10. Do you have any comments on the group of proxy companies that Mr. King has selected for his study?

A. Although Mr. King has selected a group of companies that could appropriately be included in a proxy group for setting natural gas distribution company rates of return, it should be noted that his proxy group in this proceeding contradicts his rate of return testimony in two recent proceedings before the North Dakota Public Service Commission.

For example, 18 months ago, in Case No. PU-400-00-521 involving the natural gas distribution rates of Xcel Energy, Mr. King filed testimony in which he based his recommended rate of return on DCF analyses of two groups of companies that he specifically agreed should be used to set a rate of return for gas distribution operations:

- Moody's Gas Distribution Group, and
- Five Combination Companies.

Similarly, seven months ago in Case No. PU-399-01-186, Mr. King based his recommended rate of return for Montana-Dakota's North Dakota electric operations on the results for a group of combination gas and electric utilities. In doing so, he specifically rejected the results for a group of electric utilities that were not combination companies.[3]

Now, in this proceeding concerning Montana-Dakota's North Dakota natural gas distribution rates, Mr. King rejects the use of Moody's Gas

[3] In its Findings of Fact, Conclusions of Law and Order dated April 24, 2002 in Case No. PU-399-01-186, the Commission decided that the rate of return should be based on a group of Combination companies as well as Electric-only companies that derive at least 85 percent of their revenue from regulated operations.

Distribution group and also abandons his position that Montana-Dakota's rates should be based on results from a proxy group of combination companies. Mr. King's rejection of his own recent positions raises obvious questions as to what rate of return would have been produced had Mr. King adhered to the expert opinions that he recently advocated to this Commission.

Q11. Have you used the same proxy group that Mr. King has recently advocated?

A. Yes. In my Prepared Direct Testimony, I used the same Moody's Gas Distribution group of companies that Mr. King used in Case No. PU-400-00-521. Obviously Moody's Gas Distribution proxy group indicates higher required returns than Mr. King's new proxy group. Mr. King suggests that the Zacks growth rate projection for Laclede is now much lower than when I prepared my testimony. However, updating the DCF analysis for Laclede would reduce the results of my various analyses by less than 50 basis points and would still indicate a cost of capital of approximately 12.75 percent including flotation costs and 12.2 percent without flotation costs. Since this rate of return for the Moody's Gas Distribution Group is significantly above the return produced by Mr. King's new group of proxy companies, one would have to question why the Moody's Gas Distribution group was acceptable to Mr. King last year, but not this year.

Growth Rate Estimation Method

Q12. Do you have any comments on the method Mr. King used to set growth rates in this proceeding?

A. In this proceeding, Mr. King used what he calls a "Classic" DCF approach as a starting point for estimating growth rates for his proxy companies. He then gives subjective consideration to Book Value growth rates and Historical growth rates to adjust the results of his "Classic" DCF analysis. However, as suggested by the following Table, Mr. King's subjective adjustment process appears to be biased and unexplainable.

DCF Growth Rate Approach	Mr. King's Average DCF Return Results	Basis Points Above/(Below) "Classic" Results
"Classic"	11.29%	
"Book Value"	12.18%	89
"Historical"	11.72%	43
After Incorporation Of "Book Value" and "Historical" Results	11.23%	(6)

The growth rates for Mr. King's "Classic" DCF analysis produce an average rate of return of 11.29 percent that he used as a starting point. His "Book Value" growth rates produce a significantly higher DCF return of 12.18 percent and his "Historical" growth rates also produce a significantly higher average DCF return of 11.72 percent. However, once Mr. King finishes subjectively incorporating his "Book Value" and "Historical" growth rates with his "Classic" DCF results, he gets a lower average rate of return than is produced by his "Classic" DCF

approach. This result is so contrary to the data and evidence that one must conclude that Mr. King's subjective adjustment process appears to be biased and unexplainable.

Q13. Do you object to Mr. King's objective growth rate calculations?

A. The Zack's data used in his "Classic" DCF analysis is a commonly-used source of data and is similar to the data used in my own analyses. Similarly, Mr. King's "Book Value" growth rates are essentially similar to my "Second-Stage Earnings Retention Growth" method, with the exception that he adds a component for growth expected to occur by issuing common stock at prices above book value.

However, Mr. King's historical growth rate approach is not a reasonable or valid approach to use. Although an analyst must be aware of past growth rates, and historical experience can affect investor expectations, the DCF growth rate estimate must be forward looking. Relying on historical results in this case would produce obviously incorrect gross anomalies such as the negative required rates of return that Mr. King calculated for Laclede Group (-1.11%) and WGL Holdings (-0.68%). Presumably the analysts surveyed by Zacks, and those that prepare the Value Line forecasts used to calculate Book Value growth rates, are aware of historical growth rates for each company and have considered that information in preparing their forecasts. Consequently, the forward-looking projections should receive virtually all of the weight in these circumstances, and the historical growth rates presented by Mr. King should be given virtually no weight whatsoever.

Q14. In your opinion, what is the best approach for combining the Zacks analysts' growth rates with the Book Value growth rates to produce a rate of return estimate for the companies that derive 75 percent of their revenues from natural gas distribution operations?

A. For these companies at this time the growth rate method should not require an "either/or" choice between Zacks analysts' estimates and the Book Value growth rate projections. Instead, the two sets of forward-looking projections should be combined to produce a composite result for the two groups. Consequently, I have combined the results from the two growth rate approaches by giving a two-thirds weight to Zacks analysts' forecasts and a one-third weight to the Book Value growth rate. These are the same weightings that I used in my Second-Stage Retention Growth method.

Using Mr. King's data and proxy group selection criteria, a more appropriate DCF rate of return estimate for these companies is calculated on Page 1 of Schedule 1 of Exhibit No. ___(JSG-4). This calculation uses growth rates for each company that are based on a weighted average that gives a two-thirds weight to Zacks growth rates and a one-third weight to projected Book Value growth. Because, as shown on Exhibit___(CWK-3), WGL Holdings derived less than 75 percent of its revenue from regulated natural gas operations, and therefore does not meet the selection criteria established by Mr. King, I did not include it in this re-calculation based on Mr. King's data. The average DCF rate of return estimate produced by companies that meet Mr. King's proxy criteria is **11.8 percent** before adjustment for flotation costs. When a flotation cost adjustment is added, the

indicated cost of capital for companies that meet Mr. King's selection criteria is **12.4 percent**.

Q15. Have you also calculated the return that would be indicated for companies that meet Mr. King's criteria if one were to apply equal weights to the Zacks and Book Value growth rates?

A. Yes. These results are calculated on Page 2 of Schedule 1 of Exhibit No. ___(JSG-4). With an equal weighting on the two growth rate estimates, the average DCF rate of return estimate produced by companies that meet Mr. King's proxy criteria is **12.0 percent** before adjustment for flotation costs, and **12.5 percent** after a flotation cost adjustment is added.

Dividend Yield Adjustment Factor

Q16. Is Mr. King correct in his description and assessment of the 0.625g dividend yield adjustment factor that you recommend?

A. No. Mr. King's first error occurs at page 28, lines 27-28 when he says that my 0.625g factor "assumes that the investor will not receive his/her first dividend until exactly three months from the date of purchase." This statement is factually incorrect. Attached as Exhibit ___(JSG-4), Schedule 3 is a copy of the document that was provided to Mr. King in Case No. PU-399-01-186 in response to his request for the derivation of the 0.625g factor. That response clearly indicates that if one assumes that the investor will not receive his/her first dividend until exactly three months from the date of purchase, the correct adjustment factor is **0.75g**. Thus, it is clear that the 0.625g is not based on that assumption.

Mr. King's second error occurs at page 28, line 29 where he says that "(t)he average for the next dividend increase is thus (.25+.50+.75+1.0)/4 = .625." However, as shown on Exhibit ___(JSG-4), Schedule 3 this calculation of Mr. King's misstates the source and derivation of the 0.625g factor. Instead, the 0.625 is the average of two far more complex calculations that incorporate the timing and time value of both dividends and dividend growth. The assumptions and results of these two complex calculations can be summarized as follows:

First Dividend Received In:	Dividend Increase In:	Factor Derived
3 months	6 months	0.75
0 months	6 months	0.50
Average		**0.625**

Thus, the 0.625 factor is the average of the assumption that the first dividend is received: (i) in 3 months, and (ii) immediately. The average of these two assumptions approximates the assumption that the first dividend could be received at any time during the first three months. In addition, both calculations assume that the dividend increase occurs in 6 months, which is consistent with Mr. King's assumption.

Mr. King's third error occurs when he states that his .5g factor reflects the assumption that the dividend increase is randomly distributed throughout the year and that the average delay in the dividend increase under Mr. King's assumption is one-half of a year. As shown in the preceding paragraph and Exhibit ___(JSG-4), Schedule 3, Mr. King's 0.5g factor is correct only in the extreme case that the next dividend is to be received immediately upon purchase of the stock, with no delay. However, if one must wait 3 months for the first dividend, the correct factor is 0.75g.

The average of these two extremes produces the most reasonable dividend adjustment factor: 0.625g.

Q17. If you and Mr. King both agree that it is most reasonable to assume that the next dividend increase is one-half year away, why is the appropriate dividend adjustment factor 0.625 and not 0.5?

A. Although I agree with Mr. King with regard to the assumed timing of the dividend increase, his error occurs when he mistakenly also assumes that there is no time value to money. However, one of the salient features of the DCF model is that it explicitly incorporates the time value of money in order to find the cost of capital that equates the market price of a share of stock with the expected timing and amount of future dividends. For example, if there is a 50% chance that a dividend increase will occur at the beginning of the year and a 50% chance that it will occur at the end of the year, the average expected timing of the dividend increase would be at mid-year. However, because a dividend increase received at the beginning of the year has a greater discounted present value than a dividend increase received at the end of the year, the effect of a mid-year timing assumption results in a dividend adjustment factor to the DCF model that is greater than one-half.

The fact that a dollar received today is more valuable than a dollar received one year from now is perhaps the most fundamental concept in finance. Thus, it is surprising to read Mr. King's testimony and realize that he is erroneously claiming that the equation on page 28, line 29 of his testimony is the same as the mathematical derivation in Exhibit ___(JSG-4), Schedule 3.

Benchmark Analyses

Q18. At pages 29-33, Mr. King criticizes your benchmark analyses. Are his criticisms misplaced?

A. Yes. For example, in discussing my Risk Premium analyses Mr. King sets up a "straw man" by stating that "(t)he theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials." However, that is neither my theory nor the theory that guides how I have used these analyses.

The return required by investors is estimated by my DCF analysis. But it is also true that when investors decide to purchase common stocks, rather than buy a new car or invest in long-term bonds, they are aware of and influenced by the premium that common stocks have historically earned relative to bonds. In fact, if the long-term average premium were zero or negative, it is doubtful that investors would purchase common stocks or make any equity investments at all. Indeed, through the workings of competitive markets equity investments, stock prices and bond yields all interact to force the long-term average premium to be a positive number. On a year-to-year basis, actual results are bound to differ from the long-term average and the expected risk premiums that investors require will vary significantly. However, the Risk Premium analysis is a good benchmark to determine whether the return generated by my DCF analyses is within a reasonable ballpark relative to historic average risk premiums. The greater the difference between the DCF results, the more one would have to question whether the DCF results are valid. Thus, although I do not believe that the Risk Premium results are

equal to the required rate of return, such results still provide an important perspective for evaluating the DCF results.

Q19. Does Mr. King propose a risk premium approach in his testimony?

A. Yes. At page 30, line 13 of his testimony, Mr. King refers to risk premium analysis as a "sanity check" on the results. That same type of "sanity check" is the purpose and function of my risk premium analysis.

Q20. Do you agree with Mr. King's position at page 29, lines 30-31 that "when recession threatens, the spread between bond yields and required stock returns is likely to increase?"

A. Yes. For example, the economy has been in a recession at various points during the past two years and there has been a "flight to quality" by investors who are now holding large cash balances and currently are more inclined to invest in high quality bonds than in common stocks. Consequently, the current risk premium spreads between bond yields and required stock returns are unusually high at this time.

Q21. Can you provide any examples of the unusually high risk premiums that investors currently require?

A. One indicator of investors' relative risk premium requirements can be seen from the Yield Spreads between (i) Baa-rated corporate bonds and (ii) the yields on less-risky 10-year U.S. Treasury Bonds and Aaa-rated bonds. The risk premiums required by Baa-rated corporate bonds for each month from July 1991 to August 2002 are shown on Exhibit ___(JSG-4), Schedule 4. It can be seen that for 10 years the yields on Baa-rate bonds averaged approximately 75 basis points more than the

yield on Aaa-rated bonds, but the yield spread suddenly shot up to more than 120 basis points in December 2001 and has remained at these exceptionally high levels ever since. Similarly, prior to 1999 the yield on Baa-rated bonds was generally between 150 and 200 basis points above the yield on 10-year U.S. Treasury Bonds. However, during the past two years, this yield spread has increased dramatically so that it is now approximately 330 basis points. Obviously investors' "flight to quality" and reluctance to invest in risky securities has caused the premiums required for Baa bonds to rise to the highest levels seen in the past decade. Because common stocks are considerably riskier than Baa-rated bonds, the unusually high cost of risk in the current market means that, in order to induce them to take on the additional risks of investing in common stocks, investors currently must expect to earn a premium on common stocks that is significantly greater than usual.

Q22. At page 29, lines 19-25, Mr. King suggests that a decline in interest rates causes stock prices to increase, thereby causing required returns on common stocks to decline when interest rates decline. Does this correctly describe current conditions in the financial markets?

A. No. Mr. King correctly describes the theoretical relationship that economists generally expect. If bond prices increase, causing bond yields to decline, we would generally expect investors to allocate more funds to stocks and bid up the price of common stocks. So, at least in theory, higher bond prices (and lower bond yields) should be accompanied by higher stock prices (and lower required returns on stock). However, that is <u>not</u> what has happened in the current market. During the past year, stock prices have declined while bond prices have increased. The

following changes in various indexes during the most recent 12 months illustrate the unusual nature of the current financial markets:

Index	12-Month Price Change
Bonds:	
Merrill Lynch 10+ Year Bonds	10.78%
Merrill Lynch Yankee Bonds	9.65%
Merrill Lynch Corporate Master Bonds	7.83%
Lehman Bros. U.S. Aggregate Bonds	8.71%
Stocks:	
S&P 500	-14.43%
New York Stock Exchange Composite	-10.90%
New York Stock Exchange Industrials	-9.43%
New York Stock Exchange Utilities	-37.90%
Dow Jones Composite	-11.00%
Dow Jones Industrials	-6.70%
Dow Jones Utilities	-30.78%

Source: *The Wall Street Journal Online*, September 19, 2002.

The increase in bond prices has caused interest rates to decline, but stock prices went in the opposite direction and have gone down significantly. This suggests that, despite the decline in interest rates, investors are reluctant to invest in common stocks and that they require expected stock returns that have relatively high expected risk premiums over bond yields at this time.

Q23. At page 33, lines 4-18, Mr. King claims that your Alternative Equity Investment analysis is irrelevant because he claims that "(i)nvestors in unregulated industrial, retail and transportation firms have no access to book equity value." Is he correct?

A. No. Mr. King is confusing the "primary" market for investing in hard assets such as utility plant with the "secondary" market for investing in paper assets such as already-issued common stocks. Investors who own stock in a corporation have access to returns on book equity at all times. Managers of most corporations continually consider what to do with the stockholders' cash that is held by the corporation. Managers may pay cash dividends to shareholders, or reinvest cash in a multitude of potential investments to create higher future earnings. Expected earnings on the book value of potential investments are a primary determinant of how corporations use and allocate the stockholders' money. Thus, Mr. King is incorrect. Stockholders, through managers acting as their agents, do have access to book value investments.

Q24. Does the average return on book value provide one type of "sanity check" on the level of return required by investors?

A. Yes. I have no doubt that investors in gas distribution utility assets similar to Montana-Dakota's North Dakota operations do not require the 29.4 percent return on average book value that investors in industrial companies have achieved in recent years. However, that is the average level of returns in recent years that Montana-Dakota must compete against in attracting capital.

An allowed rate of return established by the DCF method should make the value of the gas distribution operations equal to the book value of those operations in the absence of a flotation cost adjustment. In other words, the purpose of the DCF analysis is to find the rate of return that will make investors indifferent between investing to provide gas distribution service to the public or investing in, for example, U.S. Treasury bills. In contrast, when investors or corporations invest in non-regulated assets the market value of those investments has been many times the book value.

Consequently, when managers of a company evaluate possible investments they must consider the possibility of investing $1.00 in gas distribution utility assets with the expectation that the market value of those assets will be $1.00 and, thus, no value will be created for investors. On the other hand, when managers invest $1.00 in non-utility assets, they have a reasonable possibility of earning a 29 percent return on that investment and turning $1.00 of book value into $5.00 of market value.[4] Thus, while Montana-Dakota does not require anything close to a return of 29 percent on its gas distribution investments, knowledge of such potential average returns that Montana-Dakota must compete against helps place Montana-Dakota's required rate of return of 13.25 percent in perspective.

[4] The average market-to-book ratio for the S&P Industrial Index is 4.98 according to *Barron's*, September 16, 2002, page MW 46.

Relative Risk

Q25. At page 27, lines 1-7 of his testimony, Mr. King suggests that his studies indicate Montana-Dakota has risks that are far below the average for his proxy companies. Do his studies support this conclusion?

A. No. Mr. King bases his risk conclusion on a selective, anecdotal comparison of his own rate of return estimates with the capital structures and percent of revenues from gas distribution of the proxy companies.

In his capital structure analysis, Mr. King cites several companies that have below-average equity ratios and above-average rate of return requirements according to his study. From this selective observation regarding a few companies in his proxy group, Mr. King suggests that his data and analysis show a strongly inverse relationship between equity ratios and required rates of return. He then jumps to the conclusion that Montana-Dakota must be a low risk company because its common equity ratio is above average for the proxy companies.

However, Mr. King ignores several counter-examples within his own study that contradict his conclusion. For example, Southwest Gas has the lowest common equity ratio in his proxy group (31.9%), and it also has one of the lowest required returns (10.0%) according to Mr. King. Similarly, NICOR has one of the highest common equity ratios in the group (49.9%), and according to Mr. King it also has an above-average required return (12.0%). As shown on Schedule 2 of Exhibit No. ___(JSG-4), the correlation between Mr. King's estimated returns and the equity ratios of his proxy companies is relatively low and not statistically

significant. For example, the correlation between return and equity ratio in Mr. King's study is only –0.35 and there is a 29 percent probability that these two variables are either unrelated or positively correlated. Clearly, one cannot conclude from Mr. King's anecdotal study that common equity ratios are strongly or significantly inversely related to the overall risk or required rate of return that he estimated for these companies. Instead, Mr. King's data demonstrate that a company with an above-average common equity ratio, like Montana-Dakota, can also have an above-average required rate of return.

Q26. Does Mr. King's risk analysis based on the percentage of revenues derived from gas distribution operations suffer from similar shortcomings and contradictions?

A. Yes. In his analysis of gas distribution operations, Mr. King starts with the premise that companies that derive a greater share of their revenues from gas distribution operations require a lower rate of return. In other words, Mr. King claims that relative involvement in gas distribution operations is inversely related to the required rate of return for his proxy companies. However, this premise is not supported by Mr. King's data. For example, WGL Holdings derives less than 75 percent of its revenue from natural gas distribution operations (and therefore does not meet Mr. King's criteria for inclusion in the proxy group). But WGL Holdings has the lowest required rate of return according to Mr. King. Similarly, ATMOS Energy derives an above-average percentage of revenues from natural gas distribution operations, and it also has an above-average required return (12.5%) according to Mr. King. These relationships contradict Mr. King's

assumption that gas distribution operations have any significantly lower risk or required rate of return than the other operations of these proxy companies. As shown on page 2 of Schedule 2 of Exhibit No. ___(JSG-4), the correlation between the percent of revenues from gas distribution and Mr. King's return estimates is only –0.08 and not statistically significant. Thus, again one cannot conclude from Mr. King's data that there is any significant inverse relationship between relative involvement in gas distribution operations and the returns produced by Mr. King's study.

Q27. Do you have any other observations regarding Mr. King's risk analysis based on the percentage of revenues from gas distribution operations?

A. As an aside at this point, one irony of Mr. King's flawed analysis of gas distribution operations should be noted. For purposes of assessing risks and determining the allowed rate of return in this analysis, Mr. King treats Montana-Dakota's gas distribution operations as a stand-alone operation. This treatment appears in Table 11 on page 25 of his testimony, wherein he shows that MDU Utilities' Gas Distribution operation derives 100 percent of its revenue from its gas distribution business. This stand-alone treatment of Montana-Dakota's gas distribution operations also appears at page 26, lines 21-26 where Mr. King cites the high, 100 percent of revenues from gas distribution as one of the two reasons he believes Montana-Dakota should receive a below-average rate of return. I agree that Montana-Dakota's gas distribution operations should be treated as a stand-alone entity for purposes of assessing risk and establishing the allowed rate of return. The irony is that, while Mr. King agrees with me at this point in his

testimony, later, at page 33, lines 24-29, he argues that the small-size risks of Montana-Dakota's gas distribution operations should be ignored specifically because the consolidated businesses of its parent company, MDU Resources, are much larger than the stand-alone gas distribution operations. Apparently Mr. King believes that some risks should be assessed on a stand-alone basis and other risks should be evaluated on a consolidated basis. The only discernible pattern to this contradiction in his testimony is that by employing divergent views on the same topic within his testimony Mr. King is able to conclude that each source of risk is low.

Q28. In your opinion, why does Mr. King's data fail to support his conclusions?

A. His analyses are limited and appear to ignore the possibility of other types of risk that are more important for explaining differences in the required rate of return. The most important deficiency in this regard is his lack of recognition that business risks can have a significant effect on both the required rate of return on common equity and on the level of common equity in the capital structure.

For example, some companies with higher business risks might tend to offset such risks to some degree by tending to borrow less and maintaining higher common equity ratios. Similarly, some companies with low business risks might take on greater financial risks by borrowing more and tending to maintain lower common equity ratios. Because the required rate of return on common equity depends on the interaction of both business and financial risks, and because these risks often offset each other, an analysis that focuses solely on the financial risks

implied by the capital structure may not tell us much about the overall risks and required rate of return on equity of a company. At various times some companies may have capital structures and financial risks that over-compensate for their business risks and at other times some companies may have financial risks that under-compensate for their financial risks. This possibility would explain why Mr. King's data demonstrate such a weak relationship between equity ratios and required rates of return.

One source of the problem with Mr. King's analysis is a subtle, but important, misapplication of financial theory. Theory suggests that the required return on common equity should increase as a firm's common equity ratio decreases, *all other things being equal*. However, since all firms do not have the same business risks, there is not necessarily any discernable or significant relationship between common equity ratios and required rates of return on common equity when the effect of equity ratios are considered in isolation, as Mr. King has done in his analysis. Relative to the proxy group based on Mr. King's selection criteria, Montana-Dakota's below-average financial risks tend to offset the above-average business risks discussed in my Prepared Direct Testimony. This suggests that Montana-Dakota has overall risks that are about average relative to the proxy group based on Mr. King's selection criteria.

Q29. Why do you think Mr. King's data do not show any significant relationship between the percentage of gas distribution revenues and the required rate of return on common equity for his companies?

A. Because all of these companies, except WGL Holdings, derive more than 75 percent of their revenue from natural gas distribution operations, they should all be relatively close to each other in terms of overall risks. Mr. King has merely presumed that companies within his proxy group that are less diversified and more focused on gas distribution operations have less risk. However, his data clearly indicate that within his sample group there is virtually no relationship between percentage of revenues from gas distribution operations and the required rate of return on common equity that he estimated. Diversification into other lines of business may reduce the overall risks for some of these companies while such diversification may increase the overall risks of other companies. Within a sample group these variations may tend to cancel out. Thus, Mr. King's data indicate that, once one has a sample group that derives more than 75 percent of its revenues from natural gas distribution operations, the accuracy of the rate of return estimate for Montana-Dakota cannot be improved or fine-tuned by further consideration of the percentage of revenues from gas distribution operations.

Q30. At page 33, lines 24-29, Mr. King asserts that Montana-Dakota's gas distribution operations do not have higher risks associated with small size than the proxy companies. Do you agree with his reasoning?

A. No. We both agree that Montana-Dakota's gas distribution operations are relatively small, but Mr. King's only reason for objecting to size as a

consideration in comparing Montana-Dakota to the proxy companies is the fact that Montana-Dakota is a subsidiary of MDU Resources. As I noted earlier, the risk and rate of return analysis of Montana-Dakota's gas utility operations should be based on the risk of these operations on a stand-alone basis. The other diversified operations of Montana-Dakota do not reduce the risks of the gas distribution operations. The risk of those operations would be essentially the same regardless of whether MDU Resources owns the gas distribution operations or these operations are spun off as a stand-alone company. Smaller size generally implies greater risk and return requirements because adverse risk events can often have a far greater relative impact on smaller operations.

Q31. At page 26, lines 13-16, Mr. King suggests that gas distribution companies that have service territories with fast-growing populations may have lower perceived risk. Does Montana-Dakota's service territory contain a fast-growing population?

A. No. In fact, North Dakota ranked 48th among the 50 states in terms of population growth rate between 1990 and 1997. A major long-term problem and source of risk for Montana-Dakota derives from the fact that many of the small towns that it serves are experiencing declining populations. Once gas distribution facilities are constructed to serve such towns, the facilities cannot be easily moved even if the population declines significantly. The population shifts that are occurring in Montana-Dakota's service territory pose a significant risk that it may at some point be unable to recover the cost of its gas distribution investments. Consequently, and as discussed further in my Prepared Direct Testimony, Mr.

King's suggestion that Montana-Dakota should receive an allowed return below the average for the proxy group does not reflect the overall risks of the company.

Q32. Does this conclude your Prepared Rebuttal Testimony?

A. Yes.

Montana Dakota Utilities Co.

2/3 - 1/3 Growth Rate Weighting of Mr. King's Data with Companies that Derive 75% of Revenues from Gas Distribution

	66.67%			33.33%						0.625	
	Growth Rate					Dividend Yield					
Company	Zacks	Earnings Retention Growth	Stock Sales Increment	Total Book Value Growth	Weighted Average Growth Rate	Dividend	Stock Price	Base Div. Yield	Adjusted Div. Yield	DCF Return
Atmos Energy Corp.	6.43%	5.73%	3.06%	8.79%	**7.22%**	$ 1.18	$ 21.63	5.46%	**5.70%**	**12.92%**
AGL Resources	11.42%	5.82%	0.46%	6.28%	**9.71%**	$ 1.08	$ 21.76	4.96%	**5.26%**	**14.97%**
Cascade Natural Gas	5.25%	7.91%	2.20%	10.11%	**6.87%**	$ 0.96	$ 19.69	4.88%	**5.08%**	**11.95%**
Laclede Group, Inc.	4.25%	4.27%	0.92%	5.19%	**4.56%**	$ 1.34	$ 22.65	5.92%	**6.08%**	**10.65%**
NICOR, Inc.	6.10%	10.55%	0.00%	10.55%	**7.58%**	$ 1.84	$ 35.06	5.25%	**5.50%**	**13.08%**
Northwest Natural Gas Co.	6.06%	5.53%	0.00%	5.53%	**5.88%**	$ 1.26	$ 28.28	4.46%	**4.62%**	**10.50%**
People's Energy Corp.	6.80%	5.75%	0.00%	5.75%	**6.45%**	$ 2.08	$ 34.00	6.12%	**6.36%**	**12.81%**
Piedmont Natural Gas Co.	4.67%	4.52%	1.97%	6.49%	**5.28%**	$ 1.60	$ 34.45	4.64%	**4.80%**	**10.07%**
South Jersey Industries, Inc.	6.00%	5.44%	2.42%	7.86%	**6.62%**	$ 1.50	$ 32.85	4.57%	**4.76%**	**11.38%**
Southwest Gas	6.80%	4.80%	0.00%	4.80%	**6.13%**	$ 0.82	$ 22.79	3.60%	**3.74%**	**9.87%**
Average	6.38%			7.14%				4.98%		**11.8%**
Flotation Cost Adjustment										x 1.0475
Average Including Flotation Costs										**12.4%**

Sources:

Zacks	Dir. Test. Of Charles W. King, p. 15, Table 3.
Earnings Retention Growth	Dir. Test. Of Charles W. King, p. 20, Table 7.
Stock Sales Increment	Dir. Test. Of Charles W. King, p. 20, Table 7.
Dividend	Dir. Test. Of Charles W. King, p. 17, Table 5.
Stock Price	Dir. Test. Of Charles W. King, p. 17, Table 5.

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Montana Dakota Utilities Co.

50 - 50 Growth Rate Weighting of Mr. King's Data with Companies that Derive 75% of Revenues from Gas Distribution

	50.00%			50.00%						0.625	
	Growth Rate					Dividend Yield					
Company	Zacks	Earnings Retention Growth	Stock Sales Increment	Total Book Value Growth	Weighted Average Growth Rate	Dividend	Stock Price	Base Div. Yield	Adjusted Div. Yield	DCF Return
Atmos Energy Corp.	6.43%	5.73%	3.06%	8.79%	**7.61%**	$ 1.18	$ 21.63	5.46%	**5.71%**	**13.32%**
AGL Resources	11.42%	5.82%	0.46%	6.28%	**8.85%**	$ 1.08	$ 21.76	4.96%	**5.24%**	**14.09%**
Cascade Natural Gas	5.25%	7.91%	2.20%	10.11%	**7.68%**	$ 0.96	$ 19.69	4.88%	**5.11%**	**12.79%**
Laclede Group, Inc.	4.25%	4.27%	0.92%	5.19%	**4.72%**	$ 1.34	$ 22.65	5.92%	**6.09%**	**10.81%**
NICOR, Inc.	6.10%	10.55%	0.00%	10.55%	**8.33%**	$ 1.84	$ 35.06	5.25%	**5.52%**	**13.85%**
Northwest Natural Gas Co.	6.06%	5.53%	0.00%	5.53%	**5.80%**	$ 1.26	$ 28.28	4.46%	**4.62%**	**10.41%**
People's Energy Corp.	6.80%	5.75%	0.00%	5.75%	**6.28%**	$ 2.08	$ 34.00	6.12%	**6.36%**	**12.63%**
Piedmont Natural Gas Co.	4.67%	4.52%	1.97%	6.49%	**5.58%**	$ 1.60	$ 34.45	4.64%	**4.81%**	**10.39%**
South Jersey Industries, Inc.	6.00%	5.44%	2.42%	7.86%	**6.93%**	$ 1.50	$ 32.85	4.57%	**4.76%**	**11.69%**
Southwest Gas	6.80%	4.80%	0.00%	4.80%	**5.80%**	$ 0.82	$ 22.79	3.60%	**3.73%**	**9.53%**
Average	6.38%			7.14%				4.98%		**12.0%**
Flotation Cost Adjustment										x 1.0475
Average Including Flotation Costs										**12.5%**

Sources:

Zacks	Dir. Test. Of Charles W. King, p. 15, Table 3.
Earnings Retention Growth	Dir. Test. Of Charles W. King, p. 20, Table 7.
Stock Sales Increment	Dir. Test. Of Charles W. King, p. 20, Table 7.
Dividend	Dir. Test. Of Charles W. King, p. 17, Table 5.
Stock Price	Dir. Test. Of Charles W. King, p. 17, Table 5.

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Montana Dakota Utilities Co.

Relationships Between Return and Equity Ratio For Mr. King's Proxy Group

	Return	Equity Ratio
Atmos Energy Corp.	12.50%	39.00%
AGL Resources	14.00%	35.10%
Cascade Natural Gas	11.00%	42.40%
Laclede Group, Inc.	10.50%	41.70%
NICOR, Inc.	12.00%	49.90%
Northwest Natural Gas Co.	10.50%	45.50%
People's Energy Corp.	12.50%	39.20%
Piedmont Natural Gas Co.	10.00%	50.80%
South Jersey Industries, Inc.	11.00%	32.50%
Southwest Gas	10.00%	31.90%
WGL Holdings	9.50%	49.80%
Average	11.23%	41.62%
Correlation with Return		-34.80%

SUMMARY OUTPUT - RETURN AS DEPENDENT VARIABLE

Regression Statistics	
Multiple R	0.35
R Square	**0.12**
Adjusted R Square	0.02
Standard Error	0.01
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0002	0.0002	1.2397	**0.29**
Residual	9	0.0016	0.0002		
Total	10	0.0019			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	0.1412	0.0263	5.3699	0.00
Equity Ratio	-0.0695	0.0624	-1.1134	**0.29**

Sources:

Return	Dir. Test. Of Charles W. King, p. 24, Table 10.
% Equity	Dir. Test. Of Charles W. King, p. 25, Table 11.

Montana Dakota Utilities Co.

Relationships Between Return, Equity Ratio and % Gas Distribution Revenues For Mr. King's Proxy Group

	Return	Equity Ratio	% Gas Distribution
AGL Resources	14.00%	35.10%	87.10%
Atmos Energy Corp.	12.50%	39.00%	**95.60%**
Cascade Natural Gas	11.00%	42.40%	100.00%
Laclede Group, Inc.	10.50%	41.70%	92.80%
NICOR, Inc.	12.00%	**49.90%**	83.40%
Northwest Natural Gas Co.	10.50%	45.50%	97.80%
People's Energy Corp.	12.50%	39.20%	80.80%
Piedmont Natural Gas Co.	10.00%	50.80%	100.00%
South Jersey Industries, Inc.	11.00%	**32.50%**	100.00%
Southwest Gas	10.00%	**31.90%**	**85.40%**
WGL Holdings	9.50%	49.80%	**74.60%**
Average	11.23%	41.62%	90.68%
Correlation with Return		-34.80%	-8.24%

SUMMARY OUTPUT - RETURN AS DEPENDENT VARIABLE

Regression Statistics	
Multiple R	0.37
R Square	**0.14**
Adjusted R Square	-0.08
Standard Error	0.01
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	0.0003	0.0001	0.6314	**0.56**
Residual	8	0.0016	0.0002		
Total	10	0.0019			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	0.1597	0.0565	2.8252	0.02
% Equity	-0.0724	0.0661	-1.0954	**0.31**
% Gas Distribution	-0.0191	0.0509	-0.3760	**0.72**

Sources:

Return	Dir. Test. Of Charles W. King, p. 24, Table 10.
% Equity	Dir. Test. Of Charles W. King, p. 25, Table 11.
% Gas Distribution	Dir. Test. Of Charles W. King, p. 25, Table 11.

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JANUARY 22, 2002
CASE NO. PU-399-01-186

Request No. 5:

Refer to page 15, line 7: Explain why a model that assumes that the next dividend will be received today results in a multiplication of the dividend yield by (1 + .5g). Conversely, explain why the multiplication of the dividend yield by (1 + 5g) implies that the next dividend will be received today.

Response:

Please see Attachment A for a description of the derivation of the 0.75g multiplier. The derivation of the 0.5 multiplier is identical, except that it (i) moves the timing of each dividend forward one-quarter by subtracting 0.25 from the exponent in the denominator of each term in equation (1), and (ii) does not contain the (1+g) factor in the numerator until the third term in the equation.

Incorporating the assumptions that "the next dividend increase is a half year away" and the next dividend is one quarter away in the constant growth DCF model means that the current market price of a share of common stock would be:

$$P_0 = \left[\frac{D_0}{4(1+k)^{.25}} + \frac{D_0(1+g)}{4(1+k)^{.5}} + \frac{D_0(1+g)}{4(1+k)^{.75}} \right.$$

$$+ \frac{D_0(1+g)}{4(1+k)} + \frac{D_0(1+g)}{4(1+k)^{1.25}} + \frac{D_0(1+g)^2}{4(1+k)^{1.75}}$$

$$\left. \ldots + \frac{D_0(1+g)^{\infty}}{4(1+k)^{\infty}} \right] \qquad (1)$$

where,

k = the annual cost of common equity capital;

D_0 = the current annual dividend (most recent quarterly dividend multiplied by four);

P_0 = the current price per share; and

g = the expected annual dividend growth rate.

Employing the same algebraic steps used in deriving the annual dividend model results in the following DCF model:

$$k = \frac{D_0}{4P_0}\left[(1+k)^{.75} + (1+g)(1+k)^{.5} + (1+g)(1+k)^{.25} + (1+g)\right] + g \qquad (2)$$

Equation (2) assumes that the next dividend at the current rate will be received in three months, or one-quarter year. The $(1+k)^{.75}$ term in brackets is associated with this first dividend. The second dividend is assumed to be received in six months, or one-half year. This dividend also includes the annual dividend increase, hence, the second term in brackets is $(1+g)(1+k)^{.5}$.

The investor required rate of return estimated using equation (2) overstates the required rate of return for ratemaking since it includes the return that investors expect to earn during part of the year by reinvesting the dividends received in the first three quarters of the year. In other words, equation (2) describes investors' effective market required rate of return, k_{mkt}. The required rate of return estimated using this model includes the partial year return which investors have an opportunity to earn on their own by reinvesting the first three quarterly dividends. The portion of the effective market rate of return that is associated with dividend reinvestment is:

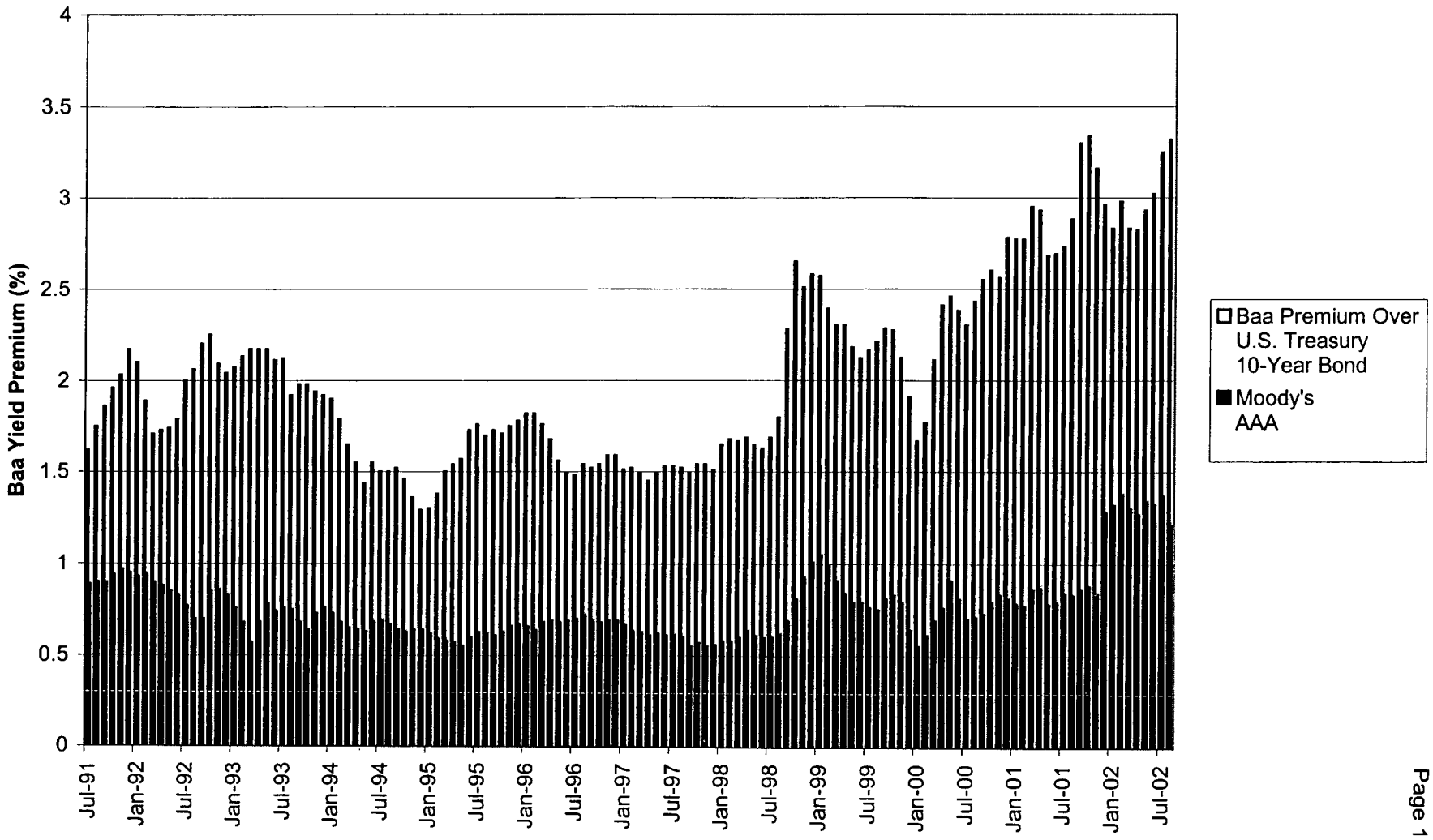
$$k_{div} = \frac{D_0}{4P_0}\left\{[(1+k)^{.75} - 1] + (1+g)\,[(1+k)^{.5} - 1] + (1+g)\,[(1+k)^{.25} - 1]\right\} \qquad (3)$$

Subtracting equation (3) from equation (2) yields the following required ratemaking rate of return, k_{reg}:

$$k_{mkt} - k_{div} = \frac{D_0}{4P_0}\left[1 + (1+g) + (1+g) + (1+g)\right] + g$$

$$= \frac{D_0}{P_0}\left[1 + .75g\right] + g. \qquad (4)$$

Premiums of Moody's Baa Bond Yields Over
Yields on 10-Year Treasuries and AAA Corporates
July 1991 to August 2002



Source: Federal Reserve Board.

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Schedule 4
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DIVIDER

STATE OF NORTH DAKOTA
INFORMATION TECHNOLOGY DEPARTMENT
SFN 2053 (4-2002)

Continued

DESCRIPTION

PU - 399 - 02 - 183

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-183

Rebuttal Testimony
of
Craig A. Keller

Q. Would you please state your name and business address?

A. Yes. My name is Craig A. Keller and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Vice President, Controller and Chief Accounting Officer (CAO) for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Craig A. Keller who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain adjustments proposed by Mr. Charles W. King and address comments made by Mr. Michael J. Majoros, Jr., testifying on behalf of the North Dakota Public Service Commission Staff (Staff).

Q. Why do you object to the inclusion of short-term debt in the makeup of the capital structure as recommended by Mr. King in his testimony?

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Rebuttal Testimony of Craig A Keller
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 23
09/24/2002 CC: Comm Legal Illona, Pat, Jerry Mike

A. I object because the materials and supplies, prepayments and fuel stocks that are included in rate base remain relatively constant, not changing materially from one month to another . While classified on the balance sheet as short-term assets, they support the long-lived assets such as plant, property, equipment and related items. It has been the Company's policy to finance these assets with long-term debt.

Q. Should the Company include Centennial Energy Holdings, Inc. (Centennial) debt as stated in Mr. King's testimony, when calculating the capital ratios and costs?

A. No. It's inappropriate for the Company to include Centennial debt, which includes Commercial Paper and Senior Notes, to calculate the debt cost for Montana-Dakota. Pursuant to the debt covenant of Centennial, only Centennial and its subsidiaries have access to this debt. This debt is unsecured and bears no ties to the utility assets. Whereas, the MDU Resources' debt is specific to utility assets secured by the First Mortgage Bond Indenture. The utility cannot access or use Centennial debt as a source of financing nor can Centennial access utility debt (First Mortgage Bond Indenture), as the assets in rate base secure utility debt. Regulated and non-regulated debt is kept separate and not commingled or fungible. Utility debt is issued when required for investment in utility assets. Certain debt was issued in the 1980's when debt costs were at some of the highest historical levels. These issues were then refinanced in the 1990's

at a substantial lower debt cost but a redemption cost was incurred as a result of the early retirement.

In his testimony Mr. King included the Centennial debt to determine the weighted average cost of debt but gave no consideration to the Centennial equity and debt when determining the capital ratios and required return. This is inconsistent and unfair as the investment in Centennial possesses a higher risk, which requires a higher equity return. Had Mr. King followed his own calculation as he suggests he would have used the entire consolidated MDU Resources Group, Inc. capital structure, which would result in a higher return requirement. Including Centennial debt for one component of the calculation but not for the entire capital structure and required return is arbitrary, selective and improper. The Company's capital structure is correct as filed.

Q. Do you agree with using December 2001 as the basis for the Capital Structure as stated by Mr. King page 4 of his rebuttal testimony?

A. No, I do not. A forecasted test period is allowed under the North Dakota Administrative Code (NDAC) 49-05-04.1. Projected costs are included when determining the level of rates and cost of service. Mr. Michael J. Majoros, Jr., in his direct testimony, accepted the projected 2003 test period for revenue requirements, while Mr. King's testimony is in direct contrast to Mr. Majoros' and is a mismatch with the rest of the revenue requirement.

The Company possesses a financial forecasting system and process that allows it to forecast effectively on a short-term basis. The projected costs used in the rate case filing are the forecasted costs used to develop the forecasted capital structure. Long-term debt schedules (balance outstanding, weighted cost, retirements) by issue are known and available when developing the long-term forecasted debt levels. Forecasted earnings are derived from projected revenue and costs that are comparable to those used in the rate case. To determine the projected equity balances, forecasted earnings are added to the actual beginning equity balance and dividends per the dividend policy are deducted from the balance. To say that the forecasted capital structure is merely a creation of the Company is unreasonable and without merit.

Q. Do you have any comments on the treatment of FAS 143 proposed by Mr. Majoros?

A. Yes. I would like to comment on the testimony of Mr. Majoros with regard to FAS 143, Accounting for Asset Retirement Obligations. The purpose of FAS 143 is to require companies to accrue for the expected retirement cost of an asset over the asset's useful life through increased depreciation. This pronouncement was intended to address nuclear power plants and similar assets where legal and environmental uncertainties could result in material retirement cost at the end of the assets useful life. After the exposure draft was issued many comments

and questions surfaced increasing the scope of the draft to include many electric and gas utility assets.

Q. How does FAS 143 compare to Montana-Dakota's current practice?

A. Historically, Montana-Dakota has set depreciation rates based on detailed depreciation studies prepared by specialists in this area. The depreciation studies incorporate assumptions and methodology common to the theories and principals applied in FAS 143. The depreciation rates are designed to match the recovery of the asset, including negative salvage, to the customers benefiting from the use of the asset. The methodology of the current depreciation system provides a systematic and straightforward process for recovering cost. This methodology is not unduly complex and is easy to update and revise on a timely basis providing a proper matching of revenue and expense. On the other hand, FAS 143 is quite complex and administratively burdensome. FAS 143 does not provide levelized depreciation rates, instead FAS 143 pushes higher cost towards the retirement date of an asset due to the discounting methods used.

The depreciation rates used by Montana-Dakota include estimates for negative salvage on interim plant retirements. The negative salvage rate incorporates actual incurred removal cost on assets retired by the Company. FAS 143 will likely result in more uncertainty since our current depreciation rates reflect removal cost for interim plant retirements whereas FAS 143 would require us to estimate the net present value of

removal cost necessary to retire plant at the date service is terminated to our customers. We currently consider this plant to have an indefinite life. Furthermore, as pointed out in Mr. John Jeter's testimony and the supporting schedules, the total depreciation and removal cost recovered from our customers would be the same regardless if we continue to use our current depreciation recovery methods or we adhere to the requirements of FAS 143. The period in which the recovery would occur would be different but since the reserve for accumulated depreciation is a reduction in rate base, the economic effect to the customer should be neutral.

It is my opinion the depreciation methodology employed by Montana-Dakota is very practical and cost effective and there would be no benefit to our customers in adopting the more complex and administrative burdensome requirements of FAS 143 for ratemaking purposes.

Q. Will Montana-Dakota be required to follow or adopt FAS 143?

A. Montana-Dakota follows Generally Accepted Accounting Principles (GAAP) and intends to implement FAS 143. The goal of Montana-Dakota would be to keep the administrative burden of complying with FAS 143 to a minimum. This could best be accomplished by implementing the standard at a higher level of detail, sufficient detail for financial reporting purposes but substantially less than would necessary for setting rates to our customers. The difference between the requirements of FAS 143 and what is allowed for regulatory accounting would result in the recording of a

regulatory asset or liability under FAS 71, *Accounting for the Effects of Certain Types of Regulation*.

R. Does this complete your rebuttal testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-183

Rebuttal Testimony
of
Richard D. Spratt

Q. Would you please state your name and business address?

A. Yes, my name is Richard D. Spratt. My business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Vice President – Human Resources of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your duties and responsibilities with Montana-Dakota?

A. I am responsible for all the disciplines in the Human Resources arena including staffing, compensation and benefits, organization development and training, organizational structure, labor and employee relations and governmental compliance with employment and employee relation's laws and practices.

Q. Would you please outline your educational and professional background?

A. Yes. I have a Bachelor of Science and Master's degree in Labor and Industrial Relations from Michigan State University. I began my HR career 25 years ago with Eaton Corporation (a 9 billion dollar fortune 100 corporation) where I was promoted through a series of HR generalist jobs, including HR Professional, Asst. HR Manager, HR Manager, Division HR

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Rebuttal Testimony of Richard D Spratt
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 27
09/24/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Manager, Group HR Manager and the last position I held with them was HR Group Director for Cutler Hammer's Power Distribution Production and International Group. I was with Eaton for approximately 21 years. I then accepted the position of VP Human Resources Controls Group with Invensys, a 20 billion dollar company based in London, UK. I was in that job approximately two years and joined Montana-Dakota in 2001 as Vice President - Human Resources, which is my current position.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the recommendation made by Mr. Michael J. Majoros, Jr. on behalf of the North Dakota Public Service Commission staff to eliminate bonuses and hold the 2003 labor costs equal to the 2002 level.

Q. On pages 3 and 15 of his testimony, Mr. Majoros described his elimination of bonuses and commissions from the Company's revenue requirement and his holding of the 2003 labor cost levels equal to the projected 2002 levels. Do you agree that this is appropriate?

A. No. This is not appropriate.

Q. At page 15, lines 9 through 11 of his testimony, Mr. Majoros claims it is unreasonable to be granting bonuses as he thinks we are in some type of recession. Do you agree with that statement?

A. No. Bonuses are an integral part of our overall compensation philosophy to remain competitive with other employers and the part of total compensation that is at risk from the employee's perspective. Whether or

not we are in a recession has no relevance to maintaining competitive wages to attract and retain a competent work force.

Q. Would you please explain why the Commission should include bonuses and commissions, and include the 2003 labor costs presented by the Company?

A. Yes, these costs should be included in this proceeding because they are legitimate costs of doing business; they are reflective of ongoing costs to execute our business strategy; they are consistent with Montana-Dakota's compensation philosophy; and, they are consistent with industry norms. Inclusion of these costs is consistent with the past practice of this Commission, most recently affirmed in the Commission's order in Case No. PU-399-01-186.

Q. What is Montana-Dakota's basic compensation philosophy?

A. It is Montana-Dakota's philosophy to compensate employees based on each position's value to the company and the value the position holds in the appropriate labor/salary market. Montana-Dakota considers base pay, bonus and incentive pay, employee benefits and the work environment as important components of the total compensation package provided. Montana-Dakota strives to construct a competitive appropriate total compensation mix that will attract, retain, and motivate employees, thus balancing the interests of customers, stockholders, and employees.

Q. How are the interests of customers balanced through the use of bonus and incentive pay?

A. The interest of customers is enhanced through the use of bonus and incentive pay because placing a portion of the employee's pay at risk for good performance focuses employees on working more efficiently to achieve better results. For example, to achieve payout of the bonus under the BETA plan, which applies to the bulk of Montana-Dakota employees, certain goals must be met. Those goals include a contribution to earnings, health care cost containment and safety measures. All of these items directly affect the cost of utility service and to the extent the goals are met, the customers, the employees and the stockholders all benefit.

Q. Is Montana-Dakota's compensation philosophy different from other companies in the utility industry?

A. Montana-Dakota's compensation philosophy is similar to most utility organizations. Each year Human Resource professionals gather data to assure company programs are appropriate and competitive. Data from the 2002 Watson Wyatt Survey Series indicated a strong trend continues to provide employees in the utility industry the opportunity for bonuses and other incentives. Approximately 60% of hourly employees, 75% of salaried employees, and 90% of management employees are eligible for bonuses in our industry. The relevant survey pages are attached as Exhibit No. ___(RDS-1). The primary reason these plans are offered is to focus and engage employees to achieve key strategic objectives of the organization.

Montana-Dakota's base pay philosophy is more conservative than many organizations in the Watson Wyatt surveys. Approximately half of the participating organizations strive to provide a total compensation package that is above the market average. Montana-Dakota strives to pay at market average.

Q. How do Montana-Dakota's salary projections for 2003 compare with others in the utility industry?

A. In an effort to provide competitive rates to our customers, Montana-Dakota has, for many years, managed its operations as economically as possible, to the point of providing very conservative wage adjustments for employees. This method of management has resulted in lower wage rates offered our employees as compared to those offered by our competition. For example:

- For exempt and non exempt office employees the combined compa-ratio (percentage of market value) currently stands at 91%. What this means is that this group of employees, on average, are currently paid 9% below what other employers in the market place are paying.
- We have a similar situation for executive pay. According to a recent study done by Towers Perrin, an executive compensation consulting group, Montana-Dakota's executive salaries are currently 11.1% below what the market is paying. If we allow this trend to occur in 2003 we will be 15% or more below what the

market pays. If you fall 10% or more behind the market you are at a much greater risk for losing employees to your competitors and you are unable to attract new talent into those vacated positions.

- The national association of compensation and benefits professionals, "WorldatWork," projects that total salary budgets will increase approximately 4% in 2003. Montana-Dakota projected that increase at only 3% in this case. Even with that increase we would still be 9 to 10 percent below the market rates.

The proposal Mr. Majoros makes on page three of his testimony to eliminate bonuses and hold labor cost levels equal to the projected 2002 levels is unreasonable as we work to keep our wage rates competitive and the deficit from widening in the labor market.

We are extremely concerned about Montana-Dakota offering competitive pay in our industry. We know if our wages consistently lag the market, it has a detrimental impact on our ability to recruit the talent we need to continue to provide safe and reliable service to our customers. This is of particular concern now as we face the reality that Montana-Dakota is going to experience a great deal of turnover within the next five years due to retirement.

Q. Has Montana-Dakota granted wage increases to its employees in past years?

A. Montana-Dakota has granted its employees modest wage increases in past years. In the last five years there were increases

granted in each year and the percentage increases granted averaged 3.7%.

Q. Are bonus and incentive plans a new component of Montana-Dakota's total compensation philosophy this year?

A. No, the Company has offered these plans and considered them a cost of doing business for many years. They are part of Montana-Dakota's total compensation mix.

Q. Are the bonus and incentive plans offered by Montana-Dakota discretionary bonuses that are determined by management opinion?

A. No, these plans have been carefully designed to pay out when key financial and productivity thresholds are met and also have a portion of payout geared toward individual goal attainment. All of this is tied back to cost effectiveness and achieving the organization's overall business goals.

Q. Could Montana-Dakota avoid a bonus payout in 2003?

A. A payout could be avoided only if the predetermined financial targets and goals are not met. The goals and payout levels were set at the close of last year for 2002. The dollars we will be paying out in 2003 are based on measures established and communicated to employees nearly a year ago.

Q. Are there advantages to customers if Montana-Dakota moves away from bonus programs?

A. In my opinion, no. If you go back to the Company's compensation philosophy, the fact still remains that Montana-Dakota needs to remain

competitive in the labor market. If bonuses were eliminated, that portion of the total compensation mix would need to be reallocated into base wages or benefit costs in order to retain and attract talent. That does not save money for our customers and might even cost money because it would have to included under some other part of compensation and would not be an incentive dependent on performance.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

BONUS AND/OR OTHER CASH COMPENSATION PAYMENTS TO OFFICE PERSONNEL (CONTINUED)

Incumbent Salary	Average % of Office Personnel Receiving	Amount Paid (as a % of Salary) First Quartile	Median	Third Quartile	Average
INDUSTRY SECTOR					
Durable Goods Manufacturing					
Under $20,000	33.0%	1.9%	3.6%	6.7%	9.3%
$20,000 to $29,999	37.1%	2.0%	3.9%	6.1%	5.9%
$30,000 to $39,999	41.7%	2.5%	3.9%	6.1%	5.0%
$40,000 or More	39.5%	2.8%	4.0%	6.6%	5.3%
All Salary Levels Combined	39.0%	2.2%	3.9%	6.1%	5.6%
Non-Durable Goods Manufacturing					
Under $20,000	20.8%	1.5%	2.5%	4.1%	3.5%
$20,000 to $29,999	28.9%	1.6%	2.7%	4.8%	3.4%
$30,000 to $39,999	32.0%	1.6%	3.0%	5.1%	4.0%
$40,000 or More	40.5%	1.9%	4.2%	6.9%	5.5%
All Salary Levels Combined	31.6%	1.6%	2.9%	5.1%	4.0%
Utilities and Energy					
Under $20,000	56.0%	3.6%	5.1%	7.6%	8.9%
$20,000 to $29,999	50.3%	2.9%	4.9%	7.7%	5.9%
$30,000 to $39,999	63.7%	3.2%	5.0%	7.9%	5.4%
$40,000 or More	75.7%	3.4%	5.9%	8.5%	6.4%
All Salary Levels Combined	59.6%	3.2%	5.2%	7.9%	5.8%
Retail and Wholesale Trade					
Under $20,000	7.5%	1.5%	2.0%	4.4%	3.6%
$20,000 to $29,999	25.1%	1.8%	3.3%	4.7%	4.5%
$30,000 to $39,999	38.3%	1.9%	3.1%	4.7%	4.0%
$40,000 or More	43.3%	2.9%	3.8%	6.0%	5.4%
All Salary Levels Combined	29.1%	1.9%	3.1%	4.8%	4.4%
ervices					
Under $20,000	13.3%	1.6%	2.8%	5.7%	4.0%
$20,000 to $29,999	23.5%	1.1%	2.6%	4.8%	3.4%
$30,000 to $39,999	33.6%	1.8%	2.2%	4.8%	3.5%
$40,000 or More	36.0%	1.7%	3.4%	6.1%	4.6%
All Salary Levels Combined	28.3%	1.6%	2.5%	4.9%	3.7%
Health Care					
Under $20,000	25.6%	2.7%	2.9%	3.1%	2.7%
$20,000 to $29,999	27.1%	1.7%	2.7%	3.0%	2.5%
$30,000 to $39,999	31.5%	1.6%	2.7%	3.0%	2.5%
$40,000 or More	24.9%	1.8%	2.8%	3.2%	3.2%
All Salary Levels Combined	27.8%	1.8%	2.8%	3.1%	2.6%
Banking and Finance					
Under $20,000	34.9%	2.1%	3.2%	5.4%	4.5%
$20,000 to $29,999	45.8%	2.2%	4.5%	7.6%	6.1%
$30,000 to $39,999	49.0%	2.3%	5.3%	9.8%	7.1%
$40,000 or More	59.6%	3.4%	7.3%	12.0%	8.7%
All Salary Levels Combined	45.9%	2.3%	4.6%	8.1%	6.3%
Insurance					
Under $20,000	46.1%	2.1%	3.7%	5.5%	5.5%
$20,000 to $29,999	54.5%	2.7%	3.9%	6.0%	5.1%
$30,000 to $39,999	62.1%	2.9%	3.9%	7.3%	6.2%
$40,000 or More	60.4%	3.0%	4.9%	8.0%	6.7%
All Salary Levels Combined	56.7%	2.9%	3.9%	6.5%	5.6%

Table continues on next page.

Bonus, Variable Pay and Long-Term Incentive Programs

SHORT-TERM PLAN PREVALENCE

BONUS AND/OR OTHER VARIABLE PAY PROGRAM(S) IN WHICH PROFESSIONAL PERSONNEL ARE ELIGIBLE

	% of Organizations with at Least One Plan	# of Responses	Prevalence of Various Plan Types (as a % of Organizations with Plans)								
			Bonus	Current Cash Profit Sharing	Team/ Small Group Incentives	Individual Incentives	Spot or Technical Achievement Awards	Gainsharing	Lump Sum Merit Pay (Not Added to Base)	Lump Sum Merit Pay (Added to Base)	Other Short-Te Incentiv
Entire Sample Combined	76.0%	1,149	77.9%	13.3%	12.0%	19.4%	27.1%	4.0%	26.1%	13.4%	11.8
Profit Status											
For-Profit Organizations	83.4%	890	82.5%	15.2%	11.9%	18.2%	26.3%	3.6%	22.9%	11.7%	12.0
Not-For-Profit Organizations	50.6%	259	51.9%	2.3%	13.0%	26.0%	32.1%	6.1%	44.3%	22.9%	10.7
Industry Sector											
Durable Goods Manufacturing	78.8%	278	75.3%	19.6%	9.6%	13.2%	20.1%	4.6%	21.5%	9.1%	15.1
Non-Durable Goods Manufacturing	86.3%	124	80.4%	18.7%	8.4%	15.9%	17.8%	2.8%	16.8%	13.1%	10.3
Utilities and Energy	89.5%	76	91.2%	4.4%	20.6%	25.0%	45.6%	4.4%	48.5%	19.1%	8.8
Retail and Wholesale Trade	82.3%	96	88.6%	7.6%	10.1%	22.8%	16.5%	2.5%	20.3%	5.1%	11.4
Services	68.6%	354	72.4%	10.7%	9.5%	21.4%	30.0%	4.1%	22.6%	17.7%	10.3
Health Care	50.0%	92	58.7%	4.3%	17.4%	13.0%	26.1%	2.2%	50.0%	21.7%	13.0
Banking and Finance	88.1%	59	84.6%	15.4%	25.0%	34.6%	48.1%	1.9%	40.4%	11.5%	17.3
Insurance	84.3%	70	84.7%	13.6%	15.3%	20.3%	33.9%	8.5%	25.4%	11.9%	6.8
Organization Size											
Under 500 FTEs	74.4%	316	76.6%	14.0%	7.7%	15.3%	18.7%	3.8%	13.2%	10.6%	19.1%
500 to 999 FTEs	74.7%	154	75.7%	16.5%	13.0%	19.1%	26.1%	4.3%	26.1%	13.9%	13.0%
1,000 to 1,999 FTEs	75.4%	179	76.3%	14.8%	16.3%	25.9%	25.9%	5.2%	30.4%	17.8%	10.4%
2,000 to 4,999 FTEs	74.9%	239	77.1%	11.7%	11.2%	16.8%	29.6%	3.9%	27.9%	12.3%	6.1%
5,000 or More FTEs	80.1%	261	82.3%	11.0%	14.4%	22.0%	35.9%	3.3%	36.4%	14.4%	8.6%

NUMBER OF BONUS AND/OR OTHER VARIABLE PAY PLANS IN WHICH PROFESSIONAL PERSONNEL ARE ELIGIBLE

	# of Plans in Place (as a % of Organizations with Plans)					
	One	Two	Three	Four	Five	Six or More
Entire Sample Combined	45.5%	26.7%	14.0%	8.4%	3.6%	1.9%
Profit Status						
For-Profit Organizations	46.0%	26.3%	14.3%	8.1%	3.4%	2.0%
Not-For-Profit Organizations	42.7%	29.0%	12.2%	9.9%	4.6%	1.5%
Industry Sector						
Durable Goods Manufacturing	47.9%	29.2%	15.1%	4.6%	2.3%	0.9%
Non-Durable Goods Manufacturing	57.0%	20.6%	12.1%	6.5%	0.9%	2.8%
Utilities and Energy	27.9%	22.1%	25.0%	13.2%	4.4%	7.4%
Retail and Wholesale Trade	50.6%	29.1%	7.6%	11.4%	0.0%	1.3%
Services	44.9%	31.7%	9.9%	9.1%	3.7%	0.8%
Health Care	45.7%	23.9%	13.0%	13.0%	4.3%	0.0%
Banking and Finance	28.8%	21.2%	21.2%	9.6%	13.5%	5.8%
Insurance	45.8%	16.9%	20.3%	8.5%	6.8%	1.7%
Organization Size						
Under 500 FTEs	49.8%	29.8%	14.0%	5.5%	0.4%	0.4%
500 to 999 FTEs	48.7%	20.9%	16.5%	8.7%	1.7%	3.5%
1,000 to 1,999 FTEs	43.0%	25.9%	11.1%	10.4%	6.7%	3.0%
2,000 to 4,999 FTEs	44.1%	30.7%	14.5%	7.8%	2.2%	0.6%
5,000 or More FTEs	41.6%	23.4%	13.9%	10.5%	7.2%	3.3%

Bonus, Variable Pay and Long-Term Incentive Programs

SHORT-TERM PLAN PREVALENCE

BONUS AND/OR OTHER VARIABLE PAY PROGRAM(S) IN WHICH MIDDLE MANAGERS ARE ELIGIBLE

	% of Organizations with at Least One Plan	# of Responses	Prevalence of Various Plan Types (as a % of Organizations with Plans)							
			Bonus	Current Cash Profit Sharing	Team/ Small Group Incentives	Individual Incentives	Spot or Technical Achievement Awards	Gainsharing	Lump Sum Merit Pay (Not Added to Base)	Lump Sum Merit Pay (Added to Base)
Entire Sample Combined	**82.0%**	**1,147**	**85.5%**	**11.2%**	**10.1%**	**20.2%**	**20.7%**	**3.3%**	**23.0%**	**11.5%**
Profit Status										
For-Profit Organizations	88.8%	909	89.3%	12.6%	10.1%	19.0%	19.4%	2.6%	21.0%	10.1%
Not-For-Profit Organizations	56.3%	238	62.0%	2.3%	10.1%	27.9%	28.7%	7.8%	35.7%	20.2%
Industry Sector										
Durable Goods Manufacturing	88.2%	272	87.3%	15.3%	8.1%	15.3%	16.5%	1.7%	17.4%	6.4%
Non-Durable Goods Manufacturing	89.0%	155	91.3%	13.0%	5.8%	15.9%	9.4%	4.3%	21.7%	7.2%
Utilities and Energy	91.5%	71	84.6%	3.1%	16.9%	20.0%	40.0%	6.2%	44.6%	16.9%
Retail and Wholesale Trade	92.4%	92	90.5%	15.5%	4.8%	22.6%	13.1%	1.2%	20.2%	9.5%
Services	72.6%	340	81.3%	8.3%	10.8%	24.9%	25.7%	3.3%	20.3%	14.9%
Health Care	55.2%	87	68.1%	2.1%	12.8%	23.4%	21.3%	8.5%	36.2%	21.3%
Banking and Finance	90.3%	62	87.5%	12.5%	25.0%	35.7%	30.4%	0.0%	30.4%	12.5%
Insurance	91.2%	68	87.1%	11.3%	9.7%	11.3%	22.6%	6.5%	22.6%	16.1%
Organization Size										
Under 500 FTEs	78.6%	309	84.5%	10.0%	7.9%	20.5%	13.8%	1.7%	9.2%	9.2%
500 to 999 FTEs	79.6%	162	83.6%	14.8%	14.1%	24.2%	20.3%	3.9%	25.8%	14.8%
1,000 to 1,999 FTEs	81.6%	179	85.1%	12.8%	10.6%	22.0%	22.7%	4.3%	29.8%	12.8%
2,000 to 4,999 FTEs	82.9%	240	84.3%	12.6%	7.6%	17.7%	23.2%	4.5%	25.3%	13.1%
5,000 or More FTEs	87.2%	257	88.8%	8.1%	12.1%	18.8%	24.7%	3.1%	30.0%	9.9%

NUMBER OF BONUS AND/OR OTHER VARIABLE PAY PLANS IN WHICH MIDDLE MANAGERS ARE ELIGIBLE

	# of Plans in Place (as a % of Organizations with Plan(s)					
	One	Two	Three	Four	Five	Six or More
Entire Sample Combined	**48.4%**	**26.6%**	**13.8%**	**6.8%**	**3.4%**	**1.0%**
Profit Status						
For-Profit Organizations	48.5%	26.8%	14.1%	6.5%	3.3%	0.9%
Not-For-Profit Organizations	48.1%	25.6%	11.6%	8.5%	4.7%	1.6%
Industry Sector						
Durable Goods Manufacturing	52.1%	28.4%	13.1%	3.8%	1.7%	0.8%
Non-Durable Goods Manufacturing	54.3%	25.4%	13.8%	5.8%	0.0%	0.7%
Utilities and Energy	26.2%	32.3%	29.2%	3.1%	7.7%	1.5%
Retail and Wholesale Trade	53.6%	25.0%	9.5%	9.5%	2.4%	0.0%
Services	46.9%	28.6%	11.2%	7.9%	4.6%	0.8%
Health Care	40.4%	29.8%	17.0%	12.8%	0.0%	0.0%
Banking and Finance	41.1%	17.9%	16.1%	10.7%	12.5%	1.8%
Insurance	56.5%	16.1%	11.3%	8.1%	4.8%	3.2%
Organization Size						
Under 500 FTEs	57.3%	24.3%	12.6%	5.4%	0.4%	0.0%
500 to 999 FTEs	40.6%	30.5%	14.8%	9.4%	3.1%	1.6%
1,000 to 1,999 FTEs	42.6%	28.4%	16.3%	5.0%	6.4%	1.4%
2,000 to 4,999 FTEs	49.5%	25.3%	12.6%	8.6%	3.5%	0.5%
5,000 or More FTEs	46.2%	26.9%	13.9%	6.3%	4.9%	1.8%

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-183

Rebuttal Testimony
of
Richard A. Espeland

Q. Would you please state your name and business address?

A. Yes, my name is Richard A. Espeland. My business address is 918 East Divide Avenue, Bismarck, North Dakota 58506.

Q. What is your position?

A. I am Vice President—Human Resources for MDU Resources Group, Inc. (MDU Resources).

Q. Are you the same Richard A. Espeland who filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the recommendation of Mr. Michael J. Mojoros, Jr. on behalf of the North Dakota Public Service Commission staff that the Supplemental Income Security Plan (SISP) not be included in the cost of service in this proceeding and to provide additional information supporting the program.

Q. What additional information are you providing?

A. Supplemental Employee Retirement Plans (SERPs) like Montana-Dakota's SISP have become common practice in utilities and related

Rebuttal Testimony of Richard A Espeland
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 28
09/24/2002 CC: Comm Legal illona, Pat, Jerry Mike

companies. Such plans provide a supplemental pension benefit to employees and are designed to provide equitable retirement benefits for certain employees. Recent studies by consulting firms such as the Hay Group indicated that 74% of the companies offer non-qualified retirement plans and Clark/Bardes Consulting has also reported that about 75% of the companies, including utilities, have non-qualified plans. This clearly indicates the common practice of providing this type of benefit. I have included the relevant pages from the above studies as Exhibit No. ___(RAE-2).

To put our retirement programs in perspective, I have prepared Exhibit No. ___(RAE-3) which has been up-dated to reflect the retirement programs available to employees, including SISP on an annuity basis. As you will note from the graph, at the lower income levels, the replacement income through the qualified retirement programs is about 84% and at the higher income levels it is only about 20%. This includes Social Security, the Defined Benefit Pension Plan and the Company match to employee contributions under the 401(k) Plan. As an employee moves up the income scale, the percentage of income replaced by retirement plans significantly decreases based on retirement plan design requirements and government limitations on retirement plans. The SISP, as a supplemental pension benefit plan, has been designed to replace some—but not all—of the income that is not replaced by Social Security, the Defined Benefit Pension Plan, and the 401(k) Plan. At the higher income levels, even with

the SISP benefit, only about 50% of the annual income is replaced. This is certainly not excessive.

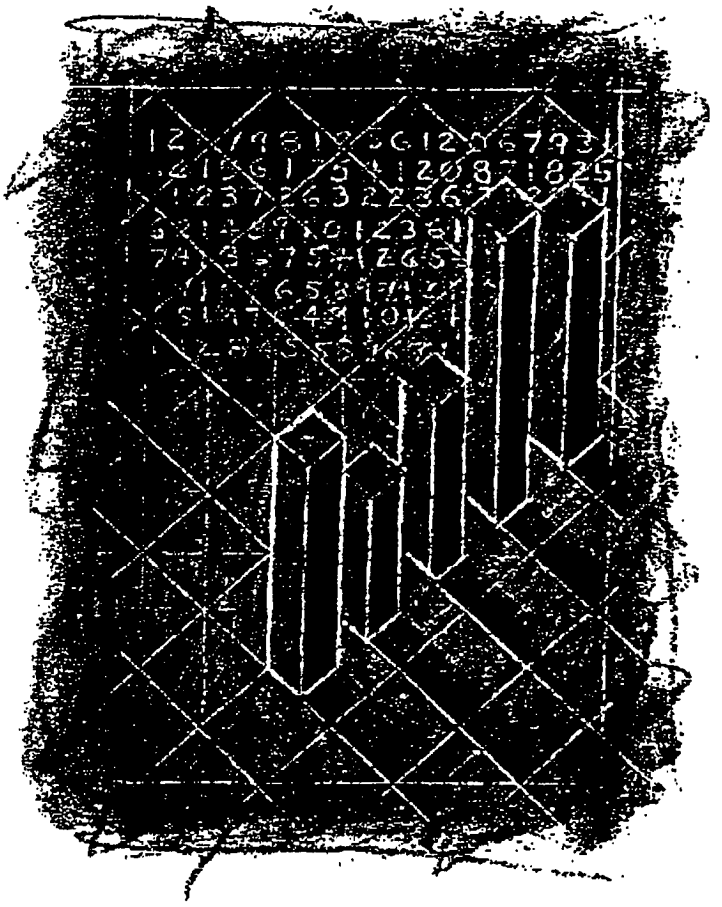
Q. Should the costs of Montana-Dakota's SISP be included in rates?

A. Yes, they should be. Supplemental non-qualified pension benefit plans like the SISP are now becoming common in the industry and other businesses and are becoming more and more an integral part of the overall compensation package. Today, a greater portion of overall compensation is placed at risk, from the employees perspective, through the now common use of bonuses and incentives based on performance. The supplemental pension benefit is necessary to attract and retain employees in key positions.

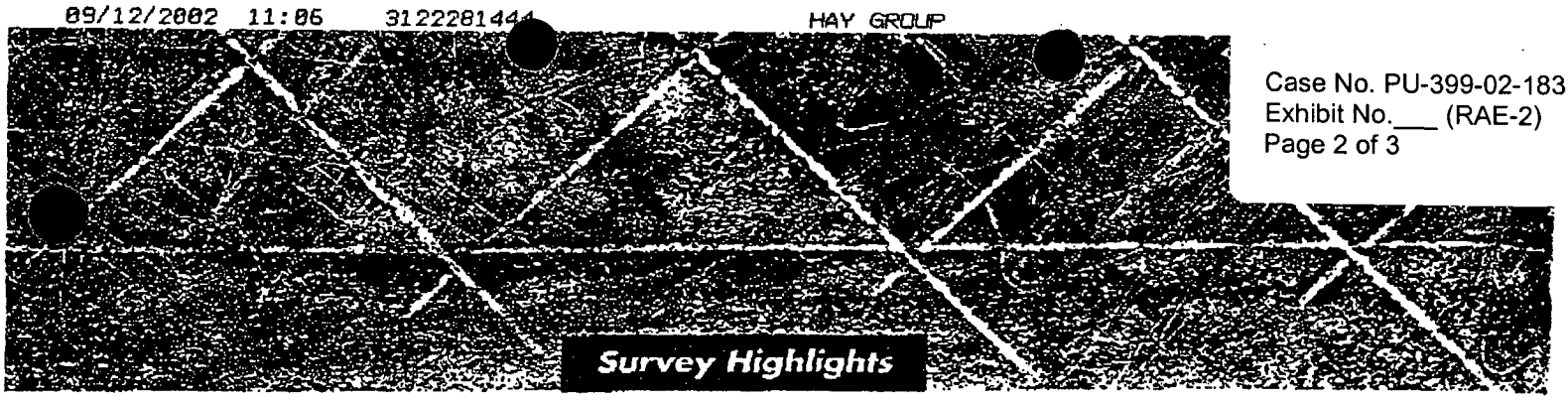
Q. Does this complete your rebuttal testimony?

A. Yes, it does.

A 2001 SURVEY



HayGroup®

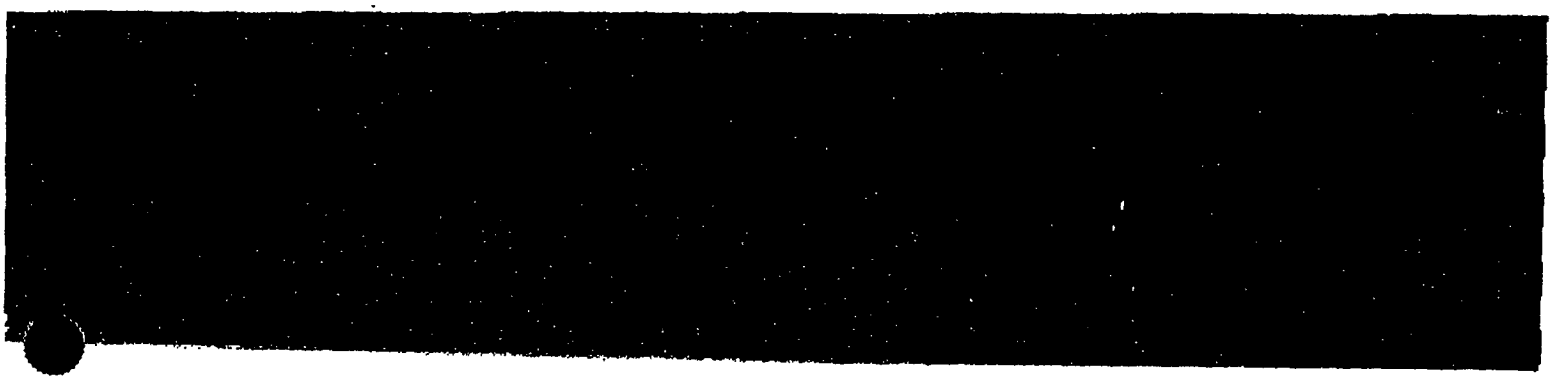


Perquisites

- Cell phones have now joined cars/car allowances as the most prevalent perquisites.
- In most perquisite categories, prevalence is significantly higher for the CEO.
- Employment Guarantee-type perquisites (employment contracts, Golden parachutes, severance) continue as the fastest growing perquisites.
- Executive Flex Plans, while on the increase, are still not widely offered, despite their flexibility for executives.

Non-Qualified Plans

- 74% of all participants sponsor some form of nonqualified retirement and/or deferred compensation arrangement.
- Prevalence of such plans varies substantially by size of organization from 56% (1,000 or fewer employees) to 91% (over 10,000 employees).
- Prevalence was considerably higher among industrial organizations (76%) and financial service organizations (90%) than among general service organizations (59%).
- Prevalence of plans was substantially higher for taxable organizations (77%) than among tax-exempt organizations (58%).
- CEOs are generally more likely to have plans than other top officers.
- Almost two-thirds of such plans (64%) offer unreduced early retirement prior to age 65.
- Target retirement ratios fall into the 50% to 70% range for three-fourths of the plans reporting, an increase over prior surveys.
- Funding, in the context of non-qualified plans, is prevalent in 77% of the plans, a major increase over prior surveys.



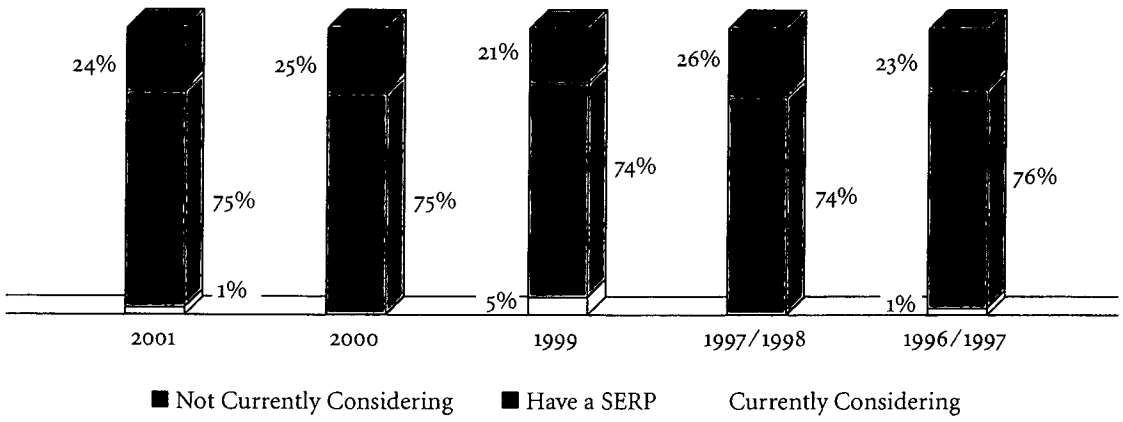
INTRODUCTION

For purposes of the Survey, a Supplemental Executive Retirement Plan ("SERP") is a nonqualified retirement plan under which the *employer* provides an additional retirement benefit to the employee. A SERP may be characterized as either a nonqualified defined contribution plan or a nonqualified defined benefit plan. Often, a SERP is tied in some fashion to the benefits provided under the employers' qualified retirement plans.

Approximately 75% of Respondents have adopted a SERP to provide benefits to executives in excess of amounts limited by qualified plan restrictions, holding steady from 2000. The primary reason for adopting a SERP is the Omnibus Budget Reconciliation Act ("OBRA") of 1993 which lowered the limit on compensation used for qualified pension calculations to $150,000 (currently indexed to $170,000 in 2001) (Internal Revenue Code [IRC] §401(a)(17)).

PLAN PREVALENCE

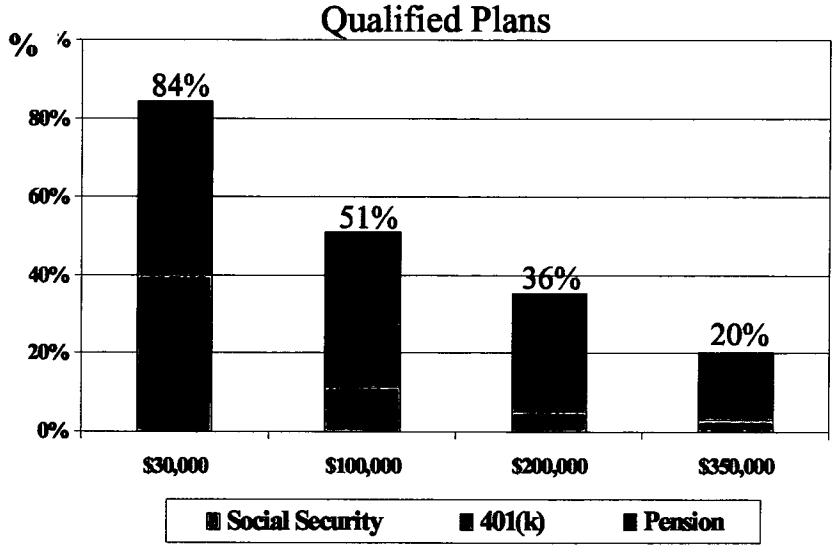
SERP PREVALENCE



SERP PREVALENCE			
Up to $2.5 Billion in Annual Revenue	Above $2.5 Billion in Annual Revenue	All Financial Institutions	All Surveyed Companies
67%	74%	84%	75%

% Retirement Replacement Income

Qualified Plans



% Retirement Replacement Income

Qualified Plans + *Non-Qualified SISP*

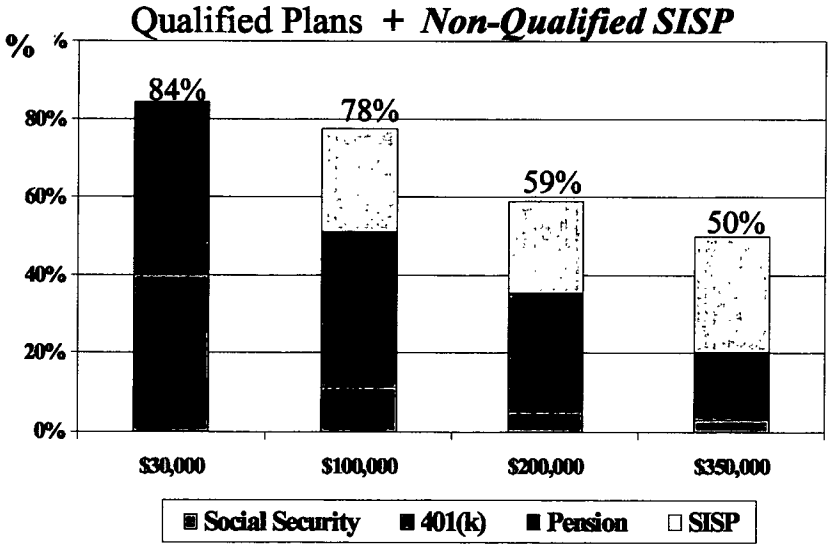


Exhibit No.___(JAJ-1)

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. **Case No. PU-399-02-183**

REBUTTAL TESTIMONY
OF
JOHN A. JETER
ON BEHALF OF
MONTANA-DAKOTA UTILITIES CO.

INTRODUCTION

Q. Please state your name and business address.

A. My name is John A. Jeter. My address is 1304 South 185th Circle, Omaha, Nebraska, 68130.

Q. What is your occupation?

A. I am a certified public accountant and I am a self-employed consultant. I retired from full time association with Arthur Andersen & Co. in 1991, after over thirty-seven years with that firm.

Q. What is the nature of the work you performed while you were with Arthur Andersen?

A. I was involved in examinations of financial statements, and to a much lesser extent, in designing and installing accounting systems. For many years I performed other financial and accounting consultation services for utility clients.

Q. What is your educational background and professional experience?

54 PU-399-02-183 Pages: 26
Rebuttal Testimony of John A Jeter
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 22
09/24/2002 CC: Comm Legal Illona, Pat, Jerry Mike

A. I am a graduate of the University of Nebraska at Omaha, from which I obtained a Bachelor of Science Degree with distinction in accounting in 1954. I was admitted to the Arthur Andersen & Co. partnership in 1967. I am a member of the American Institute of Certified Public Accountants and the Nebraska Society of Certified Public Accountants. In 1994, I was elected to the Board of Directors of Tucson Electric Power Company, and became a director of its parent company, UniSource Energy Corporation when it was formed. I retired from the UniSource board and its subsidiary boards in May, 2001. In 1991 I began consulting on my own with utilities regarding accounting and regulatory matters. As is true in this case, I have also consulted in association with Zinder Companies, Inc., a firm that provides economic and financial consultation to regulated utilities.

Q. What experience have you personally had in the utility field?

A. I have participated in or been responsible for regular audits of financial statements, registration statements filed with the Securities and Exchange Commission (SEC) for the sale of securities, installations of property records and information systems, and a variety of other special accounting services for regulated industry clients. For many years before I retired from Arthur Andersen, I had regional responsibilities in its regulated industries practice, and was a member of the partnership team that established policies with respect to issues facing clients in rate-regulated industries.

I often taught in both training sessions for Andersen personnel and in the training sessions Andersen offered to its clients and to others. This training ordinarily involved accounting issues, tax issues and various ratemaking matters.

In 1992, I prepared a paper, and presented it twice, in a tutorial sponsored by the Institute of Electrical and Electronics Engineers, Inc. Power Engineering Society. The title of my portion of the tutorial was "Accounting for Depreciation, Return, and Income Taxes."

Q. Have you previously testified before any regulatory agencies?

A. Yes. I have testified before the Federal Energy Regulatory Commission (FERC) (and its predecessor, the Federal Power Commission), the National Energy Board of Canada, the Interstate Commerce Commission and regulatory agencies in North Dakota and a number of other states, and the Province of Alberta, Canada. My testimony has addressed depreciation, accounting for income taxes, post retirement benefits other than pensions, working capital, and various other topics related to accounting and ratemaking issues. I have attached Appendix A, which is a list of my testimony in regulatory proceedings since the beginning of 1996.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota" or "the Company") to respond to the direct testimony of Mr. Michael J. Majoros, Jr. on behalf of the staff of the North Dakota Public Service Commission regarding depreciation rates.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibit No. ___(JAJ-1), Rebuttal Testimony of John A. Jeter, and Exhibit No.___(JAJ-2), Example – Statement of Financial Accounting Standards No. 143, which I prepared.

Q. Will you please summarize your conclusions?

A. Yes. The Company is using the depreciation rates included in Case No. PU-399-94-297 based on a depreciation study completed in 1992. Currently, Montana-Dakota has retained AUS Consulting to complete another depreciation study by December 31, 2002. There should be no change in depreciation rates until that study has been completed and the appropriate review has taken place as Mr. Majoros did not prepare a depreciation study, and has presented no evidence that the depreciation rates should be changed at this time. A proper depreciation study would involve reviewing additions, retirements, transfers, balances, salvage, removal costs, and accumulated depreciation for the entire history of each account in gas plant and common plant for Montana-Dakota's gas distribution operations, none of which Mr. Majoros did.

Mr. Majoros' reference to cash flow as a basis of setting depreciation rates is completely incorrect, and his use of the rough turnover estimation procedures is not reliable and is not used to establish depreciation rates when study data is available as it is in this case. His comments regarding net salvage are largely his unsupported opinions and are not based on any analysis of Montana-Dakota's facilities, experience or operations.

BACKGROUND INFORMATION

Q. Please describe the facilities being depreciated by the Company.

A. Montana-Dakota's facilities include gas distribution properties in North Dakota that are used to serve approximately 83,500 customers in 76 communities. In

addition there are common facilities that are used in connection with the electric and gas services in North Dakota and other states, the costs of which are directly assigned or allocated to the North Dakota gas operations.

DEPRECIATION

Use of Current Cash Needs to Set the Depreciation Rate

Q. On pages 5 through 9 of his testimony, Mr. Majoros discusses the relationship between cash flow and depreciation. Is this a normal type of depreciation analysis?

A. No. Mr. Majoros states that depreciation is not intended to finance additions (page 6, lines 3-4) but then compares Montana-Dakota's company-wide depreciation expense with the plant additions that were made during the years 1996-2001. It is well established that depreciation is not intended to finance plant additions, and the relationship between the two is largely meaningless for determining the appropriate time period during which the Company's plant should be depreciated. In spite of this, Mr. Majoros concludes at lines 25-26 of page 6 of his testimony that the Company ". . .is financing all of its plant additions from depreciation funds it collects from ratepayers, and still has a substantial amount of additional cash for other matters." There is no way he can support that conclusion, because he is assuming incorrectly that there are no other requirements for the cash flow.

Moreover, since depreciation is meant to recover the existing investment, it is irrelevant whether investors reinvest the recovered funds or, instead, find other uses for the funds. The appropriate depreciation rate is dictated by the need

to recover the invested capital during the life of the facilities. By ignoring that fundamental purpose of depreciation Mr. Majoros is effectively proposing that the depreciation rate should vary from time to time depending upon the amount of cash the company is investing on projects deemed by Mr. Majoros to be beneficial to ratepayers. Presumably, in years when the company has "... additional cash for other matters ..." Mr. Majoros would reduce the depreciation rate. Conversely, in years when the company needs to undertake major investments in plant, Mr. Majoros presumably would propose major increases in depreciation rates so that the company will have sufficient cash flow to fund all of its investments without borrowing, retaining earnings or issuing common stock. It is doubtful that Mr. Majoros really means to revolutionize the concept of depreciation so that customers' rates can be increased dramatically to provide financing for new investments. Nevertheless, that is the logical corollary to the new "cash-flow-needs" standard for setting depreciation rates that Mr. Majoros is advocating.

Q. Is Mr. Majoros' assertion concerning Montana-Dakota's source and uses of funds factually accurate?

A. No. In addition to the fact that the comparison he made is meaningless, the amounts he used are not comparable. The depreciation in column (2) includes depreciation of common plant, but the amounts for "Construction/Acquistion" (sic) in column (3) do not include those for common plant. During this 1996-2001 period there were $28,064,555 of additions to common plant. This changes

the "Incremental Cash Flow" in his column (4) from $28,473,000 to $408,000. (The last year shown in column (1) should be 2001 rather than 2002.)

Q. Mr. Majoros also made an analysis using just the North Dakota distribution and general plant additions and depreciation expense amounts in his Exhibit___(MJM-3). Is that any different?

A. No. It is also meaningless for similar reasons. Once again, his conclusion is completely incorrect. After observing that the depreciation expense for the years 1986-2001 exceeded the plant additions by $4.5 million, he says (lines 8-9 on page 7) "It seems that ratepayers rather than investors have been financing the Company's North Dakota plant through excessive depreciation." Interestingly, he asserts that there is "excess depreciation" and has, at this point in his testimony, mentioned no basis for that other than the comparison of depreciation cash flows and plant additions, which even he agrees are not the basis for setting depreciation rates.

Although this exhibit is meaningless, I should point out the fact that it is also incorrectly prepared. Mr. Majoros included depreciation expense for gas distribution and general facilities in column (2) of the exhibit. (See Company response to Data Request No. 29.) However, he included additions to gas distribution, general and common plant physically located in North Dakota in column (3) of his exhibit. (See Company response to Data Request No. 10.) This clear mismatch merely adds to the uselessness of the Exhibit.

Q. On Page 7 at lines 12-13, Mr. Majoros states "An excessive depreciation rate is one that produces depreciation expense more than necessary to return a

company's capital investment in an asset over the life of the asset. Do you agree?

A. No, because it is incomplete. The Federal Energy Regulatory Commission in its Uniform System of Accounts for Natural Gas Companies (also used by this Commission for the gas companies subject to its jurisdiction) defines depreciation as:

> the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.

The term "service value" is defined as the difference between original cost and net salvage value of gas plant. Since service value includes net salvage in addition to the capital investment, Mr. Majoros omitted an important aspect of the recovery of cost that is necessary through depreciation provisions.

Q. How would the omission of net salvage affect his determination of "excessive depreciation"?

A. His comparisons are not only baseless, but they are also incorrect in that the entire cost is not included in his thinking. If the net salvage is negative, and is estimated to be 30% of the asset cost, he would be asserting that, since the depreciation expense exceeds current additions, it is excessive. That is a wrong comparison to start with, but in addition, he would be leaving out the fact that the expense would

have to be 130% of the amount necessary to recover the investment, in order to provide for the negative salvage (cost of removal in excess of salvage).

Q. On page 7, line 16 to page 9, line 2, Mr. Majoros quotes a U. S. Supreme Court decision from 1934 as a basis for his contention that excessive depreciation ". . .results in the extraction of capital contributions from ratepayers." Would you please comment?

A. Yes. Mr. Majoros seems to have missed the point of the Court's ruling. He refers to a cite of this decision in the NARUC Depreciation Manual as proof that it is still relevant law. The section in which this item is cited is the "Brief History of Utility Depreciation". The NARUC text points out the fact that this decision overruled a 1930 decision for depreciation on fair value. In other words, the references to over recovery of cost meant that the depreciation on a **value** basis would over-recover **cost.** Subsequent to the *Hope Natural Gas Company* case decided by the Supreme Court in 1944, most regulatory Commissions stopped using the "value" method for measuring the rate base investment and switched, instead, to the "original cost" method of measuring rate base. To that extent, I believe the 1934 decision cited by Mr. Majoros is consistent with current regulatory practice, which generally uses an "original cost" rate base for ratemaking. I believe the references in the decision to excessive recovery of depreciation referred to the use of value rather than cost in setting rates. That is certainly not an issue in this case since neither the rate base nor the depreciation amount is derived from an estimate of the current value or replacement cost of the plant.

Accumulated Depreciation (Reserve)

Q. On page 9, lines 3-24 Mr. Majoros shows the relationship of the accumulated depreciation reserve to the plant in service and concludes that the reserves are "extraordinarily high" and that they suggest that "prior depreciation rates have been excessive." Do you agree?

A. No. Without information about the average age of the plant, prior retirements etc., it is not possible to tell at what level the accumulated depreciation provisions (reserve) should be. Once more Mr. Majoros is expressing his opinion without benefit of any evidence to support it.

Q. Are there other aspects of the level of the depreciation reserves that should be considered?

A. Yes. The amount in the reserve includes amounts that are set aside for the net negative salvage as well as the amounts needed to recover the original investment in the plant. Obviously, that makes the percentage relationship of the reserve to the plant amounts look larger than it would if only the investment recovery portion of the reserve were compared. More importantly, the larger the reserve balance is, the lower the rate base is and the lower revenue requirements for return and income taxes are. In some cases the level of the reserve can also affect the levels of property taxes paid, and reduce them if the reserve is higher.

Q. Could you quantify the effect of the lower rate base?

A. Yes, I can do that roughly. The direct effect of a lower rate base caused by a larger depreciation reserve balance is to lower the revenue requirement. If it is assumed that depreciation had been less by the amount of Mr. Majoros' proposed

annual adjustment of depreciation since rates were set to be effective in late 1994, we would have had 8 years (1995-2002) of Mr. Majoros' $2.172 million proposed depreciation expense reduction accumulated in the depreciation reserve by the end of 2002. That would have reduced the reserve by $17.376 million and increased the rate base by the same amount.

The effect of an increase in rate base of $17.376 million would be to increase the revenue requirement. I have computed those amounts using Montana-Dakota's proposed 11.044% rate of return shown in Dr. Gaske's testimony, and the 39.61% combined Federal and state income tax rate supplied to me by the Company.

Q. What are the effects on revenue requirements using those assumptions?

A. The revenue requirement avoided because the $17.376 million is in the depreciation reserve is about $3.2 million annually which exceeds the $2.2 million annual depreciation adjustment proposed by Mr. Majoros. This means that there will be a greater reduction of the revenue requirement **every year from 2002 on** by having the $17.376 in the reserve than Mr. Majoros' proposed reduction in annual depreciation expense. In addition, the revenue requirement reduction does not reduce the amount of investment being recovered by Montana-Dakota as Mr. Majoros' proposed depreciation expense reduction would. The higher depreciation reserve balances, resulting in a lower rate base, has benefited Montana-Dakota's customers and continues to be a benefit in terms of reducing the revenue requirement.

Q. On page 10, lines 2-3, Mr. Majoros states "According to the Company, 'no specific studies have been prepared regarding the adequacy of the depreciation reserve or calculation of any theoretical depreciation reserves'." Is that true, and if so, can you explain why it is true?

A. I understand it is true, and it is certainly appropriate. Theoretical depreciation reserves are discussed in the NARUC text on depreciation to which Mr. Majoros referred in his testimony. On page 24, the authors state, "If, for example, depreciation rates have been prescribed by regulatory authorities for an appreciable period in the past, it would be inconsistent to deduct, in establishing a rate base, a larger or smaller amount than the book depreciation reserve accumulated under the prescribed rates." The reason that the Company has not done studies of the adequacy of the depreciation reserves or determined theoretical depreciation reserves, is that it is inappropriate. Adjustments of depreciation are nearly always done on a prospective basis based on the determination of changes in average service lives or determinations of average remaining service lives.

Net Negative Salvage

Q. On page 10 of his testimony Mr. Majoros expresses his opinion that the 1991 depreciation study by Stone & Webster included an "extremely high" cost of removal factor for Account 380 - Services. Do you agree?

A. No. The 1991 depreciation study of Stone and Webster included a review of Account 380 additions from 1936 through 1991 and related salvage data to the extent that it was available. I would rather rely on that study than Mr. Majoros'

reaction, which seems mainly to be based on the effects of the salvage estimate rather than the basis for it.

Depreciation Lives

Q. On the same page 10 Mr. Majoros concludes that the 36-year life for Account 376 – Mains and the 34-year life for Account 380 – Services "may be excessive" based on his experience in investigating other gas depreciation rates. Will you please comment?

A. Yes. Again, I would rely on Stone & Webster's 1991 depreciation study. Mr. Majoros' opinion may be based on his experience, but his opinion was formed without any specific determination of the proper life or any specific basis for the life he would select. The Stone & Webster study used data from 1936 through 1991, and curve fitting techniques that resulted in the use of the R3 Iowa Curve to determine a 34-year life for the Account 380 – Services. The study used data from 1944 to 1991 for Account 376 – Mains, in the same manner to determine an R5 curve fit and a 36-year life.

The approach used by Stone & Webster for these two accounts is widely used by depreciation experts, including the FERC staff, to determine the appropriate lives to use to depreciate gas utility plant.

Q. On page 11 at lines 1-15 Mr. Majoros discusses the "Geometric Mean Turnover studies" he used to test service lives. Will you please comment?

A. Yes. First, his use of the word "studies" should not be interpreted to mean that he did a depreciation study. What he did is a very limited review of certain data, with some unexplained calculations. He said in the testimony that he used the last

five years of additions and retirements, however his Exhibit___(MJM-5) shows additions and retirements for the period 1985 through 2001. In addition, his exhibit labels certain of the data as a "3 Year Band" and it appears not to be for any three-year period. His schedules on Exhibit___(MJM-5) pages 1 of 4 and 3 of 4 show average plant balances in Column b for each year based on the balances at the beginning of the current year and the beginning of the prior year, which means the average balances are all shown for the wrong year. They are all actually averages for the year previous to the one shown.

The "Ave. Plant Balance", "Additions", and "Retirements" shown under the "3 Year Band" caption are, in each instance, the sum of the current year and the previous year amounts from Columns b, c and d. Thus they are not for three years, and they use those incorrect average balances from Column b. Using the data for this 17-year period, Mr. Majoros computed a life estimate of 108.07 years for Account 376 – Mains and a life of 68.53 years for Account 380 – Services. He does not explain how the data for this 17-year period is reliable, nor how the method he used works to determine the lives.

In the case of Account 376 – Mains, the $1.167 million of retirements for all the years from 1985 through 2001 are only 6.2% of the balance at the beginning of 1985, and a smaller percentage of the 1985 balance plus subsequent additions. In the NARUC depreciation text mentioned by Mr. Majoros, turnover methods are discussed in Chapter VII. The Geometric Mean turnover methods he used is described on page 81 as follows: "The *Asymptotic* method and its simplified form, the *Geometric Mean* method, are based on ratios of annual

additions and retirements. The latter method more readily indicates trends but is also prone to producing results with considerable variability. The simplicity of the turnover methods and ease with which they may be applied explain their popularity. Their use is restricted by the assumptions of uniformity and their failure to provide an indication of retirement dispersion. These problems led to their replacement by the Simulated Plant Record (SPR) model."

Further, under the caption "Limitations" on page 92 of the NARUC text, the following summary statements about turnover methods are made: "All the methods assume uniformity for the growth ratio and the dispersion of retirements for each vintage. A more reliable estimate may be made if the property has experienced at least one life cycle (roughly twice average life) since, under the constancy assumptions above, the property will be at stability. Since utility property typically does not meet the above constancy assumptions, the methods may produce considerable variation in life indications. This is especially true for the Geometric Mean method."

The 1968 edition of the NARUC text stated on page 138 that "Turnover methods are currently used very little because improved methods have been developed for determining service lives from recorded data." I do not believe Mr. Majoros' conclusions based on his very rough analysis of this data should be given any weight in determining the proper lives to use for Montana-Dakota distribution facilities.

Net Salvage – Five Year Average

Q. From page 11, line 18 to page 12, line 11, Mr. Majoros discusses net salvage ratios, and refers to his Exhibit___(MJM-6). He concludes that ". . .the Company's net salvage recovery is vastly overstated." Do you agree?

A. No. I believe the 1991 depreciation study prepared by Stone & Webster is a much more reliable source of information regarding net salvage than a cursory look at net salvage for all accounts over a five year period. I also believe that cost of removal will tend to be paid nearer the end of the average life of plant facilities and cannot be estimated accurately using broad averages of short periods of data, as was done by Mr. Majoros.

Mr. Majoros used data without so much as questioning it. The amounts by year for natural gas varied from $79,685 to $440,703. In addition, the amounts for common utility facilities varied from $12,377 in 1997 to $4,889,037 in 2001. I understand that the large amount in 2001 involved the sale of an office building for approximately $4.6 million. The electric amounts include an insurance recovery of about $1.8 million, and much of the other salvage during the period is for vehicles and work equipment. In summary, Mr. Majoros has very little basis for his comments and for the effect of net negative salvage he used in his final recommendation. I will discuss that recommendation later in this testimony.

I do not understand Mr. Majoros' comments about the recovery being "overstated". I assume the amounts being recovered are being recorded by the Company in its records. Perhaps he means that the amounts being recovered are excessive, and I have commented above about his complete lack of evidence for

that claim. He also states on page 12 that the Company's ". . .ratepayers are being penalized." The ratepayers will receive full benefit of the amounts recorded by the reduction in rate base I discussed above.

Q. Included in his discussion of salvage, on page 12 of his testimony at lines 1-2 Mr. Majoros says ". . .it appears that the Company has not recorded any net salvage at all for Services." Is that true?

A. No. I understand from Company personnel that the Company has recorded $1.4 million of net negative salvage for Services during the years 1995 through 2001. Mr. Majoros took his data from a report of retirement work in progress ("RWIP"), which, because of the use of blanket work orders, shows Services combined with Mains. That is apparently the reason he concluded that there was no net salvage applicable to Services.

Q. Mr. Majoros then guesses that the Company may be recording cost of removal in connection with Services replaced as "Service Transfer Expense". (Page 12, lines 4-6.) Is that what the Company is doing?

A. No. As I mentioned above, the Company has informed me that net salvage has been recorded in the accumulated depreciation accounts (reserve).

Q. Then to the extent that he relied on his statements about Account 380 – Services, his conclusion is completely unsupported. Is that right?

A. Yes.

Statement of Accounting Standards No. 143

Q. On page 12, lines 13-21, Mr. Majoros discusses SFAS No. 143 and the changes he believes will be required for fiscal years beginning after June 15, 2002. Will you please explain the effects of SFAS No. 143?

A. Yes. I have prepared Exhibit No. ___(JAJ-2), a simple example of the accounting changes involved. On the exhibit I have assumed a $10,000 plant is completed on January 1, 2001 and there is an estimate of $500 of cost of removal and no salvage at the time of its estimated retirement on December 31, 2010. The owner of the plant applies a credit adjusted risk-free interest rate to discount the cost of removal obligation to it present value of $254.17.

Under existing accounting, as shown in the top table on the exhibit, the depreciation expense would reflect the $500 cost of removal as an additional provision for depreciation of $50 per year and the total depreciation expense credited to the reserve for depreciation would provide for the retirement of the asset and for the cost of removal. The plant and reserve accounts would be zero at the end of the life.

Under SFAS No. 143, the $254.17 present value of the estimated cost of removal would be recorded on January 1, 2001 as a liability and as an addition to plant. Depreciation of the adjusted plant would be $1,025.42 per year instead of the $1,050 recorded under existing accounting rules. However, the present value liability must be increased each year as the time for settlement approaches. The accretion recorded to do that is the discount rate times the beginning of the year balance each year. On the exhibit that shows up as $17.79 in 2001 and increases

each year until 2010 when it is $32.71. Once again, the plant and reserve accounts, as well as the liability account all stand at zero at the end of 2010.

It is important to note that the total expense recorded under both accounting standards is the same $10,500.

Q. Will you please comment on Mr. Majoros' discussion of SFAS No. 143?

A. Yes. The new accounting standard will cause Montana-Dakota and other companies to change their accounting for retirement obligations. Mr. Majoros indicates that when Companies do not have the asset retirement obligations described in SFAS No. 143 ". . .these costs will likely be expensed. . .". If a company does not have such costs I do not understand what it is that he would expect them to expense. In addition, his comment on lines 17-18 about measuring these costs ". . .at their present value, not the future inflated value." suggests a misconception. The requirements of SFAS NO. 143 are to estimate the future cash flows expected to be spent removing facilities retired, and to discount those amounts to current present values. The required computations specifically include an adjustment for inflation that is expected to increase the nominal cost of removal from present cost levels to cost levels expected to be in effect at the time when the costs of removing retired facilities are paid. Mr. Majoros is apparently mixing the effects of inflation with the discount rate used to discount the future cash flows to present values.

Q. Do you agree that GAAP does not control ratemaking as he asserts on page 13, line 2?

A. Regulatory agencies are not required to follow the specifics of each accounting standard. Because of this, *SFAS No. 71 - Accounting for the Effects of Certain Types of Regulation* provides for the accounting necessary to reflect the effects of such regulatory actions. However, I do not think anyone knows whether the FERC or the various state regulatory agencies will follow this new accounting in setting rates, as he suggests will be done. Frequently these agencies have decided to retain the accounting for ratemaking that they have been using when the FASB publishes a new standard. I believe that is something that is yet to be decided.

Q. Is SFAS No. 143 relevant in this proceeding?

A. Yes, I believe it is. The Commission could rule in this proceeding as to the method Montana-Dakota should use in the future for recording asset retirement obligations and the related operating expenses, and how such items will be treated for ratemaking purposes. However, it is possible that the Commission will prefer to deal with the question in a rulemaking type proceeding involving all its jurisdictional companies. If it is ultimately decided that the provisions of SFAS No. 143 are to be used for ratemaking, it is obvious that those provisions are relevant. If existing practices are retained, the Company must still comply with SFAS No. 143, and differences must be accounted for under the provisions of SFAS No. 71.

Q. Mr. Majoros' recommendation concerning SFAS No. 143 is explained on page 13, line 17 to page 14, line 9. Would you please comment on those recommendations?

A. Yes. The cost of removal charged to customers already includes the legal asset retirement obligations defined in SFAS No. 143. However, I believe the Commission may require the Company to provide for similar obligations that may not meet that definition, and those costs should also be included in cost of service. I certainly do not agree that ". . .the Company's experience suggests that it does not have any such obligations." as Mr. Majoros states at the top of page 14. The definition of a "legal obligation" in SFAS No. 143 is quite broad and includes entity promises to a third party (which may include the public at large) about its intention to perform retirement activities. (See paragraph A3. of the Statement.)

I also do not agree with his comment on page 14 at lines 3-4 that ". . .the costs should be measured at their net present value." If rates are set based on SFAS No. 143 procedures, the Company must be allowed to recover depreciation of the present value of future net negative salvage, and the accretion of the liability for asset retirement obligations. The sum of these two elements of cost is equal to the undiscounted cost of removal and both must be recovered to compensate the Company for costs it is required to pay, when costs are recorded as required under the provisions of SFAS No. 143. Here again, Mr. Majoros seems to be mixing the discounting and the effects of inflation. I believe both should be taken into account in setting rates.

I do not know how the 5 year rolling average expensing approach he recommends on lines 4-9 of page 14 works. However, as I explained above, if the Commission elects to follow the provisions of SFAS No. 143 in setting rates, the costs that need to be recovered are the depreciation of the present value of the

asset retirement obligation plus the accretion applicable to the present value obligation. That accretion must be expensed each year to adjust the net present value of the obligation to the new current level. The depreciation would be the same each year for any specific obligation, but the accretion would increase over time. Consequently, it could be appropriate to use a projected average amount over several years in order to allow the recovery of the total of the two parts required to be recorded under the provisions of SFAS No. 143.

If the Commission elects to continue to follow the practices it currently follows, then the differences between the two methods should be recorded as a regulatory asset or liability. The differences would be between; 1) the recovery of the estimated net salvage on the existing basis, and 2) the expensing of the depreciation of the capitalized present value of the asset retirement obligation plus the accretion that must be recorded under the provisions of SFAS No. 143 beginning in 2003. In the long term, the amounts allowed would be the same, but the timing of the expense would be different under SFAS No. 143 from what it has been under present Generally Accepted Accounting Principles ("GAAP").

Mr. Majoros' Depreciation Recommendation

Q. Is there any basis for the depreciation recommendation shown on Mr. Majoros' Exhibit___(MJM-7)?

A. No. Mr. Majoros has ignored the previous depreciation study with regard to negative net salvage, and has also reduced the recommended provision for depreciation for 2003 by $848,000 based on a five-year average of salvage values he obtained from the Company. A review of the data shown on his

Exhibit___(MJM-6) makes it clear that this 5-year summary is not reliable for the use he made of it. If this is the 5-year average he recommended at page 14, lines 4-8, I strongly disagree with his recommendation. As discussed earlier, there were large amounts included in that exhibit that are not recurring, such as a $4.6 million sale of an office building, which should not be included in any case. That transaction is unlikely to be repeated every five years. Because of this and other problems with this approach, it should not be considered.

Mr. Majoros also allocated the common property amounts between electric and gas utilities based on the salvage amounts for each of them separately, which is not the basis used by Montana-Dakota for the allocation of common plant costs. In any case he did not support his allocation of $2,795,600 to gas operations in his testimony or on the exhibit.

The net result of Mr. Majoros' adjustments would be a $2.172 million reduction in the amount allowed for depreciation to an amount of $1.089 million. His proposed adjustment would be over 71% of the amount currently being recorded by the Company. The proposed adjustment is not supported by any evidence and should not be approved. On page 14, lines 16-17, Mr. Majoros states that these adjusted rates ". . .are still excessive because they are based on lives that are too short. They are conservative from the ratepayers perspective." I do not understand what Mr. Majoros means by "conservative" but in my opinion his proposed rates are not conservative from any standpoint. Any further reduction would make them even less conservative. With the net salvage

adjustment he made, the overall average rate he is proposing is 1.58%. It cannot be considered conservative in any way. It is almost certainly inadequate.

Q Would you please summarize your testimony?

A. Yes. No adjustment of depreciation rates should be entertained until the current depreciation study is completed and an appropriate review has taken place. Current rates are based on a comprehensive study prepared in 1991 and used beginning in 1994. Mr. Majoros has not done a depreciation study and has no basis for suggesting the changes in depreciation rates he is proposing. His review of the depreciation rates currently in effect is entirely superficial and contains many errors. Thus the depreciation rates should not be changed based on Mr. Majoros' proposal.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Montana-Dakota Utilities Co.
Listing of Regulatory Testimony of John A. Jeter
1996-2002

Year	Juris-diction	Company	Issues	Docket Number	Date Filed
1996	Tx.	Texas-New Mexico Power Company	Depreciation adjustments - Direct	15560	5/2/96
1996	Tx.	Texas-New Mexico Power Company	Depreciation adjustments - Supplemental	15560	9/6/96
1996	Tx.	Texas-New Mexico Power Company	Depreciation adjustments - Rebuttal	15560	11/15/96
1996	FERC	Transcontinental Gas Pipe Line Corp	Depreciation - Answering	RP95-197	5/31/96
1996	FERC	Northern Border Pipeline Company	Income tax & Depreciation-Answering	RP96-45-000	6/18/96
1996	Okla.	Public Service Company of Oklahoma	Pension, OPEB, and Deferred Income Taxes-Direct	PUD 960000214	11/15/96
1997	Okla.	Public Service Company of Oklahoma	Pensions, working capital-rebuttal	PUD 960000214	8/18/97
1997	FERC	Transcontinental Gas Pipe Line Corp	Depreciation-Answering	RP97-71-000	8/22/97
1999	La.	Southwestern Electric Power Company	Consolidated Income Tax Effects	U-23029	8/10/99
1999	Tx.	Central Power and Light Company	Securitization of Reg. Assets-Direct	21528	10/18/99
1999	Tx.	Central Power and Light Company	Securitization of Reg Assets-Rebuttal	21528	12/3/99
2000	Tx.	Central Power and Light Company	Energy Delivery 1st Tariff-Consolidated Tax Direct*	22352	11/30/00
2000	Tx.	West Texas Utilities Company	Energy Delivery 1st Tariff-Consolidated Tax Direct*	22354	11/30/00
2000	Tx.	Central Power and Light Company	Energy Delivery 1st Tariff-Consolidated Tax Rebut	22352	12/7/00
2000	Tx.	West Texas Utilities Company	Energy Delivery 1st Tariff-Consolidated Tax Rebut	22354	12/7/00
2002	FERC	Portland Natural Gas Transmission System	Gas Pipeline Depreciation - Answering	RP02-13-000	6/18/02

* In each of these cases I adopted the direct testimony of Mary Z. Brennan

Montana-Dakota Utility Co.
Example - Statement of Financial Accounting Standards No. 143

Assumptions:

Cost of plant	$ 10,000.00	Discount rate under SFAS No. 143	7.00%
Life of plant in years	10	Present value of estimated cost of removal	$254.17
Estimated cost of removal	$ 500.00	Plant added on 1/1/01	

Existing Accounting					
		Depreciation Reserve			
Year	Plant	Depreciation Expense	Plant Retirement	Cost of Removal	Balance
2001	$10,000.00	$ 1,050.00			$1,050.00
2002	10,000.00	1,050.00			2,100.00
2003	10,000.00	1,050.00			3,150.00
2004	10,000.00	1,050.00			4,200.00
2005	10,000.00	1,050.00			5,250.00
2006	10,000.00	1,050.00			6,300.00
2007	10,000.00	1,050.00			7,350.00
2008	10,000.00	1,050.00			8,400.00
2009	10,000.00	1,050.00			9,450.00
2010	-	1,050.00	10,000.00	500.00	-
		$ 10,500.00			

Accounting Under SFAS No. 143									
			Depreciation Reserve				Liability for Cost of Removal		
Year	Total Expense	Plant	Expense	Plant Retirement	Balance	Beginning Balance	Accretion	Payment	Ending Balance
2001	$ 1,043.21	$ 10,254.17	$ 1,025.42		$1,025.42	$254.17	$17.79		$271.97
2002	1,044.46	10,254.17	1,025.42		2,050.83	271.97	19.04		291.00
2003	1,045.79	10,254.17	1,025.42		3,076.25	291.00	20.37		311.37
2004	1,047.21	10,254.17	1,025.42		4,101.67	311.37	21.80		333.17
2005	1,048.74	10,254.17	1,025.42		5,127.09	333.17	23.32		356.49
2006	1,050.37	10,254.17	1,025.42		6,152.50	356.49	24.95		381.45
2007	1,052.12	10,254.17	1,025.42		7,177.92	381.45	26.70		408.15
2008	1,053.99	10,254.17	1,025.42		8,203.34	408.15	28.57		436.72
2009	1,055.99	10,254.17	1,025.42		9,228.76	436.72	30.57		467.29
2010	1,058.13	-	1,025.42	10,254.17	-	467.29	32.71	500.00	-
	$10,500.00		$ 10,254.17				$245.83		

SFAS 143 Exh JAJ2

Case No. PU-399-02-183
Exhibit No.___ (JAJ-2)
Page 1 of 1

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-183

Rebuttal Testimony
of
Rita A. Mulkern

Q. Would you please state your name and business address?

A. Yes. My name is Rita A. Mulkern and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Analysis Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Rita A. Mulkern who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to address certain adjustments proposed by Mr. Michael J. Majoros, Jr., testifying on behalf of the North Dakota Public Service Commission Staff (Staff).

Q. On page 15 of Mr. Majoros' testimony, he proposes a five-year amortization of rate case expense instead of the three years the Company is requesting. Do you agree with his proposal?

No, I do not. The sole rationale Mr. Majoros sets forth for a five-year amortization is because of the period between rate cases.

53 PU-399-02-183 Pages: 6
Rebuttal Testimony of Rita A Mulkern
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 25
09/24/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Presumably he is referring to the fact that the last general rate case was filed in 1994. However, just because it has been eight years since the last general rate case does not mean that it will be five years before the next rate case. Montana-Dakota was able to refrain from filing for a rate increase during that time because it took actions to increase efficiencies and reduce costs, using new technologies where possible rather than seeking an increase in rates, all addressed by Mr. Fox in his direct testimony. Montana-Dakota will continue to strive for operating efficiencies and cost reductions, but it is not anticipated that it can replicate past performance and refrain from filing for another five years. Montana-Dakota believes that a three-year amortization provides the best time frame for rate case expense amortization.

Optionally, if the Commission does decide that a five-year amortization is appropriate, the unamortized rate case expense balance should be included as a rate base addition.

Q. On page 16 of his testimony, Mr. Majoros proposes to eliminate the inflation amount from the proposed level of other expenses. What is wrong with his adjustment?

A. Mr. Majoros does not allow these costs because they have not previously been allowed and he does not recommend that they start now. Mr. Majoros appears to be missing the point of this item. Montana-Dakota is using a projected 2003 test year. In projecting 2002-2003 expenses, costs were broken down into major categories. As shown on Statement

N, page 14, the items adjusted individually (labor, benefits, insurance, advertising and rate case expense) make up 71 percent of the total per books 2001 operation and maintenance (O&M) expense. The remaining 29 percent are real costs incurred by the Company and not likely to remain flat just because they were not individually adjusted. This category includes such items as materials, postage, vehicles and work equipment expense, uncollectible accounts, etc. The last time the Commission addressed the use of an inflation factor was in July 1991, over eleven years ago. It is time to recognize that these costs are subject to inflationary pressures just as the other identified items have been. For example, we know that postage expense, included in the inflation adjustment, increased effective July 1, 2002. The proposed inflation on other O&M items should be allowed as proposed.

Q. On page 2, lines 11-12 of his testimony, Mr. Majoros makes the comment that the proposed increase "will be superimposed on those already resulting from spikes in the market price of gas". Do you agree with that statement?

A. No, I do not. First, Montana-Dakota's gas costs have been very stable over the long-term, with the exception of the winter of 2000-2001 where there was a large spike in gas costs, both in North Dakota and nationwide. Exhibit No.___(RAM-2) is a graph showing a history of gas costs included in customers' rates through the monthly Purchased Gas Cost Adjustment (PGA) for the period January 1999 through October

2002. As can be seen on the graph, gas costs have been very stable, with the exception of the winter of 2000-2001, and in fact have been slightly lower in 2002 than in previous years.

Second, Mr. Majoros seems to be implying that when reviewing a rate case application, one should take into account the changes in the cost of gas. However, the cost of gas is not a part of the rate case.

Q. On page 5 of his testimony, Mr. Majoros states that " a 5.7 percent expense growth rate is not reasonable" for the period 2000 to 2003. Do you agree with his statement?

A. No, I do not. Mr. Majoros' statement is unsubstantiated and made without looking to determine if there are reasons for such an increase. There are certain items, identified in my direct testimony, that increased significantly in 2002. For example, pension and postretirement expenses both increased in the 10-15 percent range due to the market performance and lower interest rates. Insurance expense also increased significantly in 2002, an event that has been experienced nationwide. Mr. Majoros has no evidence to back up his statement, and thus, given the current cost levels, a 5.7 percent increase is entirely reasonable and explainable.

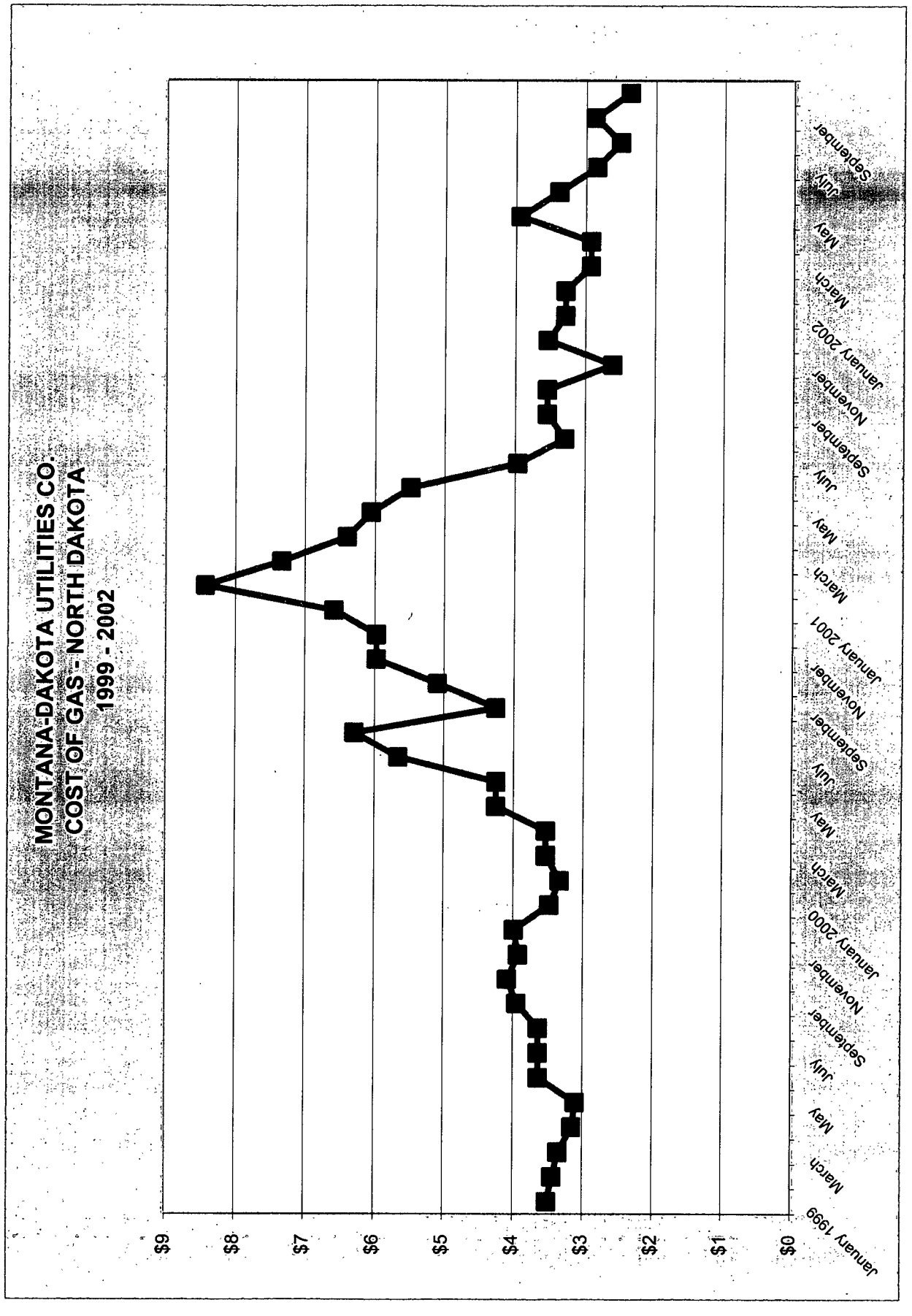
In fact, the actuarial reports for pension and postretirement costs for 2003 were just received and the results show that the pension and postretirement expenses included in the cost of service for 2003 are significantly understated. The updated expense for these items results in an increase in North Dakota gas pension expense of $150,000 and in

postretirement expense of $90,000 above the 2003 levels included in the rate case. The increase in expense is due to the lower investment returns in 2001-2002. This higher level of expense is now known and should be recognized in the revenue requirement for 2003.

In addition, medical costs for 2003 have also increased significantly from the levels included in the projected 2003 test year, and are now projected to be $189,000 over the amount in the case.

Q. Does that complete your rebuttal testimony?

A. Yes, it does.


MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - NORTH DAKOTA
1999 - 2002
$9
$8
$7
$6
$5
$4
$3
$2
$1
$0
January 1999
March
May
July
September
November
January 2000
March
May
July
September
November
January 2001
March
May
July
September
November
January 2002
March
May
July
September

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-02-183

Rebuttal Testimony
of
Tamie A. Aberle

Q. Would you please state your name and business address?

A. Yes. My name is Tamie A. Aberle, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Pricing & Tariff Manager in the Regulatory Affairs Department of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Tamie A. Aberle who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of this rebuttal testimony is to address recommendations made by Mr. Charles King, testifying on behalf of the North Dakota Public Service Commission Staff, regarding the embedded cost of service study and rate design.

Q. Would you please explain why you do not agree with Mr. King's position with regard to the Company's allocation of mains to the customer

component as he describes beginning at page 38 of his testimony?

A. Yes. The allocation of a portion of gas distribution mains to the customer component is a standard practice throughout the gas industry. The June 1989 version of the Gas Distribution Rate Design Manual prepared by the NARUC Staff Subcommittee on Gas states at page 22:

> "Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied."

The manual further states-

> "A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial. One argument for inclusion of distribution related items in the customer cost classification is the "zero or minimum size main theory". This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires."

Also, the cost of service study example provided in the NARUC Gas Distribution Rate Design Manual reflects the use of the zero or minimum size main theory and provides for the allocation of a portion of the mains investment to the customer component. Distribution mains are

appropriately allocated to the customer component by virtue of the fact that distribution mains exist because customers exist.

Q. Do you agree with Mr. King that the only time main additions are required is when a gas main is extended in order to serve new developments in previously unserved areas and that the customer allocation of mains is irrational for the customers served through the existing embedded system of gas mains as stated on page 39 of his testimony?

A. No, I do not agree with either premise purported by Mr. King in regard to the allocation of the Company's investment in mains. Main additions are not made only at the very edges of the system to provide service to new developments. Main additions are also required for purposes of enhancing system integrity and maintaining pressure requirements throughout the system as customer additions occur. Mr. King's analogy of a line originally installed to serve a single factory under the commercial rate that ultimately provides service to both residential and commercial customers is not a valid example using customer allocation and does not offer further support for his proposed allocation of mains on an energy related basis nor is it relevant to Montana-Dakota system's. The class cost of service study represents the allocation of embedded costs on an aggregate basis and not by line segment.

Q. Mr. King asserts that the heating content of the gas is the value delivered, and should be the allocator of the main's cost. Do you agree?

A. No. Main investment is not a variable cost that increases or decreases as more or less gas is used. The heating content is one value delivered but the capability to have natural gas service available on demand is the cost of having the main in place to serve customers. The value of the heating content does not represent the Company's embedded cost or the causation of the cost required to deliver natural gas to the customer.

Q. Is the allocation of mains presented by Mr. King consistent with past Commission practices?

A. No it is not. The peak day allocator used by the Commission in past cases did not assign any peak day usage to the interruptible classes on the premise that these customers do not contribute to the peak day design of mains. The peak day allocation factor used by Mr. King (as taken from the Company's study), includes an assignment based on a 100% load factor imputation of demand for the interruptible customers. This coupled with the allocation based on annual throughput results in an excessive amount of mains being allocated to the interruptible customers. Mr. King's study is further flawed because the allocation based on annual throughput includes the volumes sold or transported to transmission level customers who are not utilizing the distribution mains in order to use natural gas service. Exhibit No.___(TAA-4) provides the results of allocating mains 50% based on throughput @ the distribution level and 50% based on peak day use for the firm customers. The returns by

customer class, with this change in allocation factors, are as shown below:

Residential Service	6.367%
Firm General Service	1.106%
Air Force	69.369%
Small Interruptible	40.905%
Small Interruptible Transport	57.738%
Large Interruptible Transport	27.320%

Q. Are you in agreement with Mr. King's allocation of the rate increase as set forth at lines 1-6, page 47 of his testimony?

A. No, I am not. Based on either the Company's class cost of service study or a class study based on Mr. King's proposed allocation of mains as modified and set forth in Exhibit No.___(TAA-4), an increase to the Air Force, Small Interruptible or Large Interruptible classes is not warranted. Mr. King provided no basis for furthering the subsidization provided by the interruptible classes by allocating an increase to those customer classes that are already providing a return on rate base in excess of the overall return on rate base. Furthermore, the recovery an any increase in total revenues to be collected from the interruptible classes is at risk given the flexible rate provision applicable to this group of customers. Presently, approximately 20% of the small interruptible volumes and 80% of the large interruptible volumes are transported under discounted rates.

Q. Please comment on Mr. King's allegation that the very low-use customers will find the increases in their average monthly bill extortionate as noted

on page 48 of his testimony.

A. The monthly Basic Service Charges proposed by the Company are cost based and not reflective of extortionate pricing. As depicted on the attached bill comparison (Exhibit No.___TAA-5), which reflects the change in rates for residential customers at varying levels of consumption, the maximum increase per month is $5.20 which would only be applicable to those customers using zero gas volumes in a particular month. The proposed rate structure should have no adverse impact on the customer's incentive to conserve their use of natural gas in order to avoid paying high gas bills as the cost of gas itself is the major component of the bill and that component is not affected by the Company's proposal. What the proposed price structure will do is provide relief to customers during the winter months when their heating requirements result in higher gas use by lowering the amount collected on a volumetric basis and sending an accurate price signal.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
SUMMARY REPORT
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Operating Income and Rate of Return	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible
Operating Revenues	95,413,769	52,583,826	34,744,169	4,931,783	1,946,328	624,476	583,187
Elimination of Unbilled Revenues	6,333,652	3,534,224	2,335,226	332,402	130,989	0	811
Adjustment to Operating Revenues	(34,111,944)	(17,742,221)	(12,641,390)	(2,759,326)	(670,672)	(61,663)	(236,672)
Adjusted Operating Revenues	67,635,477	38,375,829	24,438,005	2,504,859	1,406,645	562,813	347,326
Operating Expenses							
Cost of Gas	77,058,145	42,310,356	29,567,926	3,485,448	1,694,415	0	0
Adjustment to Cost of Gas	(28,065,930)	(15,412,151)	(10,769,989)	(1,267,554)	(616,236)	0	0
Other O&M Expense	12,722,671	8,277,661	4,023,334	48,424	108,723	145,049	119,480
Total Operation & Maint. Exp.	61,714,886	35,175,866	22,821,271	2,266,318	1,186,902	145,049	119,480
Depreciation	3,059,361	1,673,729	1,230,214	10,390	40,258	61,832	42,938
Taxes Other Than Income Taxes	1,225,459	733,483	437,547	5,114	13,421	19,947	15,947
Fed. & State Inc. Taxes - Current	4,322,345	1,824,003	1,200,205	823,084	165,921	152,865	156,267
Tax Effect of Adjustments	100,673	421,454	162,339	(405,779)	26,794	(21,583)	(82,552)
Deferred Income Taxes	(4,031,683)	(2,119,850)	(1,499,361)	(278,571)	(134,074)	138	35
Total Operating Expenses	66,391,041	37,708,685	24,352,215	2,420,556	1,299,222	358,248	252,115
Operating Income	1,244,436	667,144	85,790	84,303	107,423	204,565	95,211
Rate Base	19,317,964	10,477,466	7,753,545	121,528	262,619	354,299	348,507
Rate of Return	6.442%	6.367%	1.106%	69.369%	40.905%	57.738%	27.320%

Case No. PU-399-02-183
Exhibit No.___ (TAA-4)
Page 1 of 18

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Cost of Service By Component	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Firm General Demand	Firm General Energy	Firm General Customer
Rate Base	19,317,964	2,758,814	2,375,954	5,342,698	1,883,755	1,684,586	4,185,204
Operating Income for Proposed Return	2,133,477	304,683	262,400	590,048	208,042	186,046	462,214
Current Operating Income	1,244,436	(642,641)	2,754,233	(1,444,448)	(438,805)	1,996,392	(1,471,797)
Increase in Operating Income	889,041	947,324	(2,491,833)	2,034,496	646,847	(1,810,346)	1,934,011
Related Taxes for Increase							
Federal Income	583,128	621,353	(1,634,401)	1,334,433	424,269	(1,187,412)	1,268,524
Total Increase in Revenue	1,472,169	1,568,677	(4,126,234)	3,368,929	1,071,116	(2,997,758)	3,202,535
Adjusted Revenue Before Increase	67,635,477	12,245,157	20,304,022	5,826,650	8,361,165	14,529,875	1,546,965
Total Cost of Service Required From Rates	69,107,646	13,813,834	16,177,788	9,195,579	9,432,281	11,532,117	4,749,500
Less Cost of Gas Items Recovered thru PGA	48,776,394	12,207,455	14,577,663	0	8,335,422	10,381,976	0
Net Distribution Costs	20,331,252	1,606,379	1,600,125	9,195,579	1,096,859	1,150,141	4,749,500
Billing Units at Customer							
Dk Throughput	35,875,902	7,681,994	7,681,994	0	5,470,992	5,470,992	0
Bills	993,588	0	0	859,416	0	0	132,276
Peak Day Dk Demand	192,268	114,254	0	0	78,014	0	0
Unit Cost of Service							
$ Per Dk		0.209	0.208	0.000	0.200	0.210	0.000
$ Per Customer Per Month		0.000	0.000	10.700	0.000	0.000	35.906

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

	Air Force			Small Interruptible Sales		
Cost of Service By Component	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base	0	53,129	68,399	0	149,084	113,535
Operating Income for Proposed Return	0	5,868	7,554	0	16,465	12,539
Current Operating Income	1,249	98,425	(15,371)	653	143,361	(36,591)
Increase in Operating Income	(1,249)	(92,557)	22,925	(653)	(126,896)	49,130
Related Taxes for Increase						
Federal Income	(819)	(60,708)	15,037	(428)	(83,232)	32,225
Total Increase in Revenue	(2,068)	(153,265)	37,962	(1,081)	(210,128)	81,355
Adjusted Revenue Before Increase	271,114	2,223,057	10,688	141,702	1,233,625	31,318
Total Cost of Service Required From Rates	269,046	2,069,792	48,650	140,621	1,023,497	112,673
Less Cost of Gas Items Recovered thru PGA	271,101	1,931,807	0	141,695	929,275	0
Net Distribution Costs	(2,055)	137,985	48,650	(1,074)	94,222	112,673
Billing Units at Customer						
Dk Throughput	1,018,005	1,018,005	0	489,700	489,700	0
Bills	0	0	36	0	0	888
Peak Day Dk Demand	0	0	0	0	0	0
Unit Cost of Service						
$ Per Dk	(0.002)	0.136	0.000	(0.002)	0.192	0.000
$ Per Customer Per Month	0.000	0.000	1,351.389	0.000	0.000	126.884

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
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	Small Interruptible Transport			Large Interruptible Sales		
Cost of Service By Component	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base	0	280,480	73,819	0	0	0
Operating Income for Proposed Return	0	30,976	8,153	0	0	0
Current Operating Income	0	215,198	(10,633)	0	(515)	(39)
Increase in Operating Income	0	(184,222)	18,786	0	515	39
Related Taxes for Increase						
Federal Income	0	(120,832)	12,322	0	338	26
Total Increase in Revenue	0	(305,054)	31,108	0	853	65
Adjusted Revenue Before Increase	0	488,103	74,710	0	0	0
Total Cost of Service Required From Rates	0	183,049	105,818	0	853	65
Less Cost of Gas Items Recovered thru PGA	0	0	0	0	0	0
Net Distribution Costs	0	183,049	105,818	0	853	65
Billing Units at Customer						
Dk Throughput	1,030,440	1,030,440	0	0	0	0
Bills	0	0	864	0	0	0
Peak Day Dk Demand	0	0	0	0	0	0
Unit Cost of Service						
$ Per Dk	0.000	0.178	0.000	0.000	0.000	0.000
$ Per Customer Per Month	0.000	0.000	122.475	0.000	0.000	0.000

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
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Cost of Service By Component	Large Interruptible Transport Demand	Energy	Customer
Rate Base	0	234,533	113,974
Operating Income for Proposed Return	0	25,902	12,587
Current Operating Income	0	97,213	(1,448)
Increase in Operating Income	0	(71,311)	14,035
Related Taxes for Increase			
Federal Income	0	(46,773)	9,206
Total Increase in Revenue	0	(118,084)	23,241
Adjusted Revenue Before Increase	0	291,914	55,412
Total Cost of Service Required From Rates	0	173,830	78,653
Less Cost of Gas Items Recovered thru PGA	0	0	0
Net Distribution Costs	0	173,830	78,653
Billing Units at Customer			
Dk Throughput	2,246,820	2,246,820	0
Bills	0	0	108
Peak Day Dk Demand	0	0	0
Unit Cost of Service			
$ Per Dk	0.000	0.077	0.000
$ Per Customer Per Month	0.000	0.000	728.269

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

	LINE ITEM		ALLOCATION FACTOR	
	PLANT IN SERVICE:			
375	Structures & Improvements	128,275	13	Distribution Mains
		4,218		Direct to Firm General Customer
		13,406		Direct to Air Force Customer
		34,218		Direct to Large Int. Transport Customer
376	Mains	**13,539,941**	**4**	**Dk Throughput @ Distribution**
		13,539,942	**5**	**2-Day Peak @ Distribution**
378	Meas. & Reg. Sta. Equip. - General	515,796	13	Distribution Mains
		4,297		Direct to Air Force Customer
379	Meas. & Reg. Sta. Equip. - City Gate	157,422	13	Distribution Mains
		6,887		Direct to Firm General Customer
		9,693		Direct to Small Int. Transport Customer
383	Service Regulators	1,626,217	10	Wtd. Customers @ Distrib. Excl. AF & LI
		25,149		Direct to Firm General Customer
		6,574		Direct to Small Int. Sales Customer
		15,879		Direct to Small Int. Transport Customer
		3,596		Direct to Large Int. Transport Customer
385	Indust. Meas. & Reg. Sta. Equip.	91,370	13	Distribution Mains
		26,056		Direct to Firm General Customer
		94,126		Direct to Air Force Customer
		4,322		Direct to Small Int. Sales Customer
		5,149		Direct to Small Int. Transport Customer
		150,005		Direct to Large Int. Transport Customer
380	Services	12,124,678	10	Wtd. Customers @ Distrib. Excl. AF & LI
381	Meters	11,983,141	10	Wtd. Customers @ Distrib. Excl. AF & LI
386.1	Other Property on Customer's Premises	1,680	13	Distribution Mains
386.2	CNG Refueling Station	113,207	13	Distribution Mains
386.3	Gas Plant Leased to Others	11,374	13	Distribution Mains
387.1	Cathodic Protection	443,741	13	Distribution Mains
387.2	Other Equipment	331,598	13	Distribution Mains
374	Land & Land Rights	86,523	13	Distribution Mains
389	Land & Land Rights - Common	208,685	13	Distribution Mains
389	Land & Land Rights - General	154,460	13	Distribution Mains
	General Plant	6,772,597	15	Distribution Plant
	Intangible Plant - General	207,216	15	Distribution Plant
	Common Plant	4,969,608	15	Distribution Plant
	Intangible Plant - Common	1,813,895	15	Distribution Plant
114.2	Acquisition Adjustment - Propane	97,266	15	Distribution Plant
	ACCUMULATED RESERVE FOR DEPRECIATION REPORT:			
376	Mains	20,582,529	13	Distribution Mains
375	Structures & Improvements	101,150	17	Structures & Improvements
378	Meas. & Reg. Sta. Equip. - General	261,901	18	Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. Equip. - City Gate	48,134	19	Meas. & Reg. Eqpt.- City Gate
380	Services	12,202,943	10	Wtd. Customers @ Distrib. Excl. AF & LI
381	Meters	4,364,018	10	Wtd. Customers @ Distrib. Excl. AF & LI
383	Service Regulators	642,471	20	Service Regulators
385	Indust. Meas. & Reg. Sta. Equip.	156,443	21	Ind. Meas. & Reg. Sta. Eqpt.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

	LINE ITEM		ALLOCATION FACTOR	
386.1	Other Property on Cust Prem.	748	13	Distribution Mains
386.2	CNG Refueling Station	82,301	13	Distribution Mains
386.3	Gas Plant Leased to Others	3,634	13	Distribution Mains
387.1	Cathodic Protection	197,290	13	Distribution Mains
387.2	Other Equipment	286,962	13	Distribution Mains
374.2	Land Rights	30,884	13	Distribution Mains
	General Plant	3,498,224	15	Distribution Plant
	Intangible Plant - General	197,933	15	Distribution Plant
	Common Plant	2,592,530	15	Distribution Plant
	Intangible Plant - Common	643,890	15	Distribution Plant
	CONSTRUCTION WORK IN PROGRESS REPORT:			
	CWIP in Service pending Classification	165,033	15	Distribution Plant
	OPERATING REVENUE REPORT:			
	Residential	19,231,623		Direct to Residential Demand
		30,990,104		Direct to Residential Energy
		5,732,149		Direct to Residential Customer
	Firm General	13,131,623		Direct to Firm General Demand
		22,352,466		Direct to Firm General Energy
		1,487,237		Direct to Firm General Customer
	Air Force	427,093		Direct to Air Force Demand
		4,825,640		Direct to Air Force Energy
		9,840		Direct to Air Force Customer
	Small Interruptible Sales	223,226		Direct to Small Int. Sales Demand
		1,819,393		Direct to Small Int. Sales Energy
		31,185		Direct to Small Int. Sales Customer
	Small Interruptible Transportation	538,661		Direct to Small Int. Transport Energy
		80,410		Direct to Small Int. Transport Customer
	Large Interruptible Sales	0		Direct to Large Int. Sales Demand
		11,939		Direct to Large Int. Sales Energy
		900		Direct to Large Int. Sales Customer
	Large Interruptible Transportation	495,568		Direct to Large Int. Transport Energy
		71,000		Direct to Large Int. Transport Customer
	Unbilled Revenue	(6,333,648)	26	Sales Revenue
	Other Operating Revenue			
	Reconnect Fees			
	Seasonal	4,466	11	Average Res. & Firm General Cust.
	Non-Payment Disconnect	10,396	11	Average Res. & Firm General Cust.
	NSF Check Fees	7,818	11	Average Res. & Firm General Cust.
	Work for Contractors, Municipalities & Others	55,318	24	Net Gas Plant in Service
	Energy Diversion	0	24	Net Gas Plant in Service
	CNG Compression & O&M Charges	(588)	24	Net Gas Plant in Service
	Rent From Gas Property			
	Buildings	22,375	24	Net Gas Plant in Service
	Equipment	17,051	24	Net Gas Plant in Service
	Parking Lot	330	24	Net Gas Plant in Service

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
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TWELVE MONTHS ENDED DECEMBER 31, 2001

	LINE ITEM		ALLOCATION FACTOR	
	Cost of Service-G.O. Complex	158,004	24	Net Gas Plant in Service
	Miscellaneous	500	24	Net Gas Plant in Service
	Other Gas Revenues			
	Sale of Sundry Junk	422	15	Distribution Plant
	Sale of Operating/Construction Material	614	15	Distribution Plant
	Patronage Dividends	3,052	31	O&M Excl. Cost of Gas
	Miscellaneous	4,504	31	O&M Excl. Cost of Gas
	Transport & Sales Penalty Revenue - Net	3,104	23	Sales & Transportation Rev.
	OPERATION & MAINTENANCE EXPENSE REPORT:			
	Cost of Purchased Gas	19,231,623		Direct to Residential Demand
		22,965,646		Direct to Residential Energy
		13,131,623		Direct to Firm General Demand
		16,355,764		Direct to Firm General Energy
		427,093		Direct to Air Force Demand
		3,043,369		Direct to Air Force Energy
		223,226		Direct to Small Int. Sales Demand
		1,463,980		Direct to Small Int. Sales Energy
		0		Direct to Large Int. Sales Demand
		0		Direct to Large Int. Sales Energy
813	Other Gas Supply Expenses	215,821	3	Dk Sales
870	Operation Supervision & Maintenance	516,162	27	All Other Dist. Operation Exp.
871	Load Dispatch	70,675	1	Dk Throughput
874	Mains & Services	878,937	22	Mains & Services
875	Measuring Stations - General	35,628	18	Meas. & Reg. Sta. Eqpt.- General
876	Measuring Stations - Industrial	37,388	21	Ind. Meas. & Reg. Sta. Eqpt.
877	Measuring Stations - City Gate	7,257	19	Meas. & Reg. Eqpt.- City Gate
878	Meters & House Regulators	585,682	16	Meters & Regulators
879	Customer Installations	760,312	10	Wtd. Customers @ Distrib. Excl. AF & LI
880	Other Gas Distribution	1,421,151	27	All Other Dist. Operation Exp.
881	Rents	20,705	27	All Other Dist. Operation Exp.
885	Maintenance Supervision & Engineering	272,457	28	All Other Dist. Maintenance Exp.
886	Structures & Improvements	2,317	17	Structures & Improvements
887	Mains	118,089	13	Distribution Mains
889	Measuring Stations - General	25,142	18	Meas. & Reg. Sta. Eqpt.- General
890	Measuring Stations - Industrial	4,594	21	Ind. Meas. & Reg. Sta. Eqpt.
891	Measuring Stations - City Gate	410	19	Meas. & Reg. Eqpt.- City Gate
892	Services	116,078	12	Weighted Customers @ Distribution
893	Meters & House Regulators	103,235	16	Meters & Regulators
894	Other Equipment	185,730	28	All Other Dist. Maintenance Exp.
901	Customer Accounts	229,995	8	Average Customers
902	Meter Reading	583,212	10	Wtd. Customers @ Distrib. Excl. AF & LI
903	Customer Records & Collection	1,519,399	8	Average Customers
904	Uncollectible Accounts	343,493	8	Average Customers
905	Miscellaneous Customer Accounts	158,847	8	Average Customers
907	Customer Service & Info.	165,359	8	Average Customers
911	Sales Expenses	470,362	8	Average Customers
920	Administration & General	4,090,058	30	O&M Excl. Gas Cost and A&G

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

	LINE ITEM		ALLOCATION FACTOR	
	DEPRECIATION EXPENSE REPORT:			
376	Mains	1,122,277	13	Distribution Mains
375	Structures	4,323	17	Structures & Improvements
378	Meas. & Reg. Sta. - General	11,908	18	Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. - City Gate	4,768	19	Meas. & Reg. Eqpt.- City Gate
380	Services	980,295	10	Wtd. Customers @ Distrib. Excl. AF & LI
381	Meters	301,513	10	Wtd. Customers @ Distrib. Excl. AF & LI
383	Service Regulators	38,945	20	Service Regulators
385	Measuring & Reg. Equip. - Indust.	7,085	21	Ind. Meas. & Reg. Sta. Eqpt.
386.1	Other Property on Cust Prem.	10,742	13	Distribution Mains
387.2	Other Equipment	39,473	13	Distribution Mains
374	Land Rights	1,152	13	Distribution Mains
	General Plant	127,855	15	Distribution Plant
	Amort. of Intangible Plant - General	2,511	15	Distribution Plant
	Common Plant	220,058	15	Distribution Plant
	Amort. of Intangible Plant - Common	185,393	15	Distribution Plant
386.3	Gas Plant Leased to Others	1,063	13	Distribution Mains
	TAXES OTHER THAN INCOME REPORT:			
	Ad Valorem Taxes			
	Distribution Plant	489,087	15	Distribution Plant
	General Plant/Intangible	52,125	15	Distribution Plant
	Common Plant/Intangible	62,617	15	Distribution Plant
	Other Taxes - Payroll, Franchise, Other	621,628	31	O&M Excl. Cost of Gas
	DEFERRED INCOME TAXES REPORT:			
	Management Incentive Compensation	(26,796)	25	Total Gas Plant in Service
	Pension Expense	296,215	25	Total Gas Plant in Service
	Sundry Reserves	2,192	25	Total Gas Plant in Service
	Reserve For Deferred Maintenance	2,235	25	Total Gas Plant in Service
	Property Insurance Adjustment	(8,384)	25	Total Gas Plant in Service
	Bad Debt Expense	13,351	23	Sales & Transportation Rev.
	Accrued Vacation	21,968	31	O&M Excl. Cost of Gas
	Capitalized Overheads	(148,861)	25	Total Gas Plant in Service
	Customer Advances Total	26,724	11	Average Res. & Firm General Cust.
	Restricted Stock Bonus Plan	22,298	31	O&M Excl. Cost of Gas
	FAS 106 -OPRB	13,504	31	O&M Excl. Cost of Gas
	Deferred Compensation - Directors	(6,837)	31	O&M Excl. Cost of Gas
	Board of Directors - Retirement Benefits	(104,470)	31	O&M Excl. Cost of Gas
	Demand Charges	7,028	2	2-Day Peak Sales
	PCB Related Income	(3,081)	25	Total Gas Plant in Service
	Asbestos Related Income	0	25	Total Gas Plant in Service
	Liberalized Deprec. & Other Prop. Timing Differ.	(36,824)	25	Total Gas Plant in Service
	Contributions in Aid of Construction	(25,346)	11	Average Res. & Firm General Cust.
	ND - Normalized Timing Differences	(56,326)	25	Total Gas Plant in Service
	Unrecovered Purchased Gas Costs	(3,998,746)	3	Dk Sales

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LINE ITEM		ALLOCATION FACTOR	
Rate Case Expense	0	30	O&M Excl. Gas Cost and A&G
Amort. of Loss on Bond Retirements	(42,324)	24	Net Gas Plant in Service
FAS 106 Deferred Expense	(22,313)	31	O&M Excl. Cost of Gas
Gas IRP	(20,993)	3	Dk Sales
Closing/Filing and Out of Period & Fed & State FA	64,093	25	Total Gas Plant in Service
Accumulated Balance 12/31/01	(4,271,992)	25	Total Gas Plant in Service
INCOME TAXES REPORT:			
Interest Charges	1,013,654	24	Net Gas Plant in Service
Deductions			
Management Incentive Compensation	(67,648)	25	Total Gas Plant in Service
Pension Expense	747,828	25	Total Gas Plant in Service
Sundry Reserves	5,536	25	Total Gas Plant in Service
Reserve For Deferred Maintenance	5,813	25	Total Gas Plant in Service
Property Insurance Adjustment	(21,165)	25	Total Gas Plant in Service
Bad Debt Expense	33,706	23	Sales & Transportation Rev.
Accrued Vacation	55,460	31	O&M Excl. Cost of Gas
Capitalized Overheads	(375,817)	25	Total Gas Plant in Service
Customer Advances	67,468	11	Average Res. & Firm General Cust.
Restricted Stock Bonus Plan	56,295	31	O&M Excl. Cost of Gas
FAS 106 - OPRB	33,145	31	O&M Excl. Cost of Gas
Deferred Compensation - Directors	(17,259)	31	O&M Excl. Cost of Gas
Board of Directors - Retirement Benefits	(263,746)	31	O&M Excl. Cost of Gas
Demand Charges	17,742	2	2-Day Peak Sales
PCB Related Income	(4,985)	25	Total Gas Plant in Service
Asbestos Related Income	0	25	Total Gas Plant in Service
Plant Reclassification	(7,677)	25	Total Gas Plant in Service
Liberalized Depreciation & OPTD	(552,874)	25	Total Gas Plant in Service
Contributions in Aid of Construction	(42,068)	11	Average Res. & Firm General Cust.
Purchased Gas Cost Adjustment	(10,095,293)	3	Dk Sales
Rate Case Expense	0	30	O&M Excl. Gas Cost and A&G
Amort. of Loss on Bond Retirements	(106,850)	24	Net Gas Plant in Service
FAS 106 - Deferred Expense	(56,330)	31	O&M Excl. Cost of Gas
Gas IRP	(53,000)	24	Net Gas Plant in Service
Disallowed Meals & Entertainment	(25,609)	31	O&M Excl. Cost of Gas
Federal Non-Hwy. Use Tax Credit	(3,859)	25	Total Gas Plant in Service
Preferred Dividend Paid Deduction	13,572	25	Total Gas Plant in Service
State Income Tax	861,216	35	Taxable Income
Rounding & Prior Year Adjustments	(30,408)	25	Total Gas Plant in Service
Taxable Income @ Federal Tax Rate	35.00%		Direct Input
Credits & Adjustments	(54,273)	35	Taxable Income
WORKING CAPITAL REPORT:			
Materials & Supplies	381,856	15	Distribution Plant
Prepaid Insurance	21,567	25	Total Gas Plant in Service
Unamortized Gas IRP Costs - Other	123,984	3	Dk Sales
Fuel Stocks	18,683		DK Sales - Propane Dk only

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2001

LINE ITEM			ALLOCATION FACTOR
INVESTMENT TAX CREDIT BALANCE REPORT:			
Investment Tax Credit Balance	(273,541)	25	Total Gas Plant in Service
RATE BASE REPORT:			
Customer Advances for Const.	(161,802)	11	Average Res. & Firm General Cust.
Direct to Firm	(10,000)		Direct to Firm Customer
Direct to Firm	(13,161)		Direct to Firm Customer
Direct to Firm	(21,545)		Direct to Firm Customer
Direct to Firm	(11,780)		Direct to Firm Customer
Direct to Small Int Transport	(49,571)		Direct to Small Int Transport Customer
ADJUSTMENTS TO PER BOOKS:			
Revenues:			
Residential	(7,024,168)		Direct to Residential Demand
	(10,718,053)		Direct to Residential Energy
	0		Direct to Residential Customer
Firm General	(4,796,201)		Direct to Firm General Demand
	(7,845,189)		Direct to Firm General Energy
	0		Direct to Firm General Customer
Air Force	(155,992)		Direct to Air Force Demand
	(2,603,334)		Direct to Air Force Energy
	0		Direct to Air Force Customer
Small Interruptible Sales	(81,531)		Direct to Small Int. Sales Demand
	(587,776)		Direct to Small Int. Sales Energy
	(1,365)		Direct to Small Int. Sales Customer
Small Interruptible Transportation	(54,353)		Direct to Small Int. Transport Energy
	(7,310)		Direct to Small Int. Transport Customer
Large Interruptible Sales	0		Direct to Large Int. Sales Demand
	(11,939)		Direct to Large Int. Sales Energy
	(900)		Direct to Large Int. Sales Customer
Large Interruptible Transportation	(206,833)		Direct to Large Int. Transport Energy
	(17,000)		Direct to Large Int. Transport Customer
Unbilled Revenues	6,333,648	26	Sales Revenue
Cost of Gas:			
	(7,024,168)		Direct to Residential Demand
	(8,387,983)		Direct to Residential Energy
	(4,796,201)		Direct to Firm General Demand
	(5,973,788)		Direct to Firm General Energy
	(155,992)		Direct to Air Force Demand
	(1,111,562)		Direct to Air Force Energy
	(81,531)		Direct to Small Int. Sales Demand
	(534,705)		Direct to Small Int. Sales Energy
	0		Direct to Large Int. Sales Demand
	0		Direct to Large Int. Sales Energy

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LINE ITEM		ALLOCATION FACTOR
COST OF SERVICE BY COMPONENT REPORT:		
Operating Income for Proposed Return	11.044%	
Related Taxes for Increase		
Inverse Tax Rate for Federal & State Income	60.390%	
Billing Units @ Customer		
Dk Throughput	7,681,994	Direct to Residential Energy
	5,470,992	Direct to Firm General Energy
	1,018,005	Direct to Air Force Energy
	489,700	Direct to Small Int. Sales Energy
	1,030,440	Direct to Small Int. Transport Energy
	0	Direct to Large Int. Sales Energy
	2,246,820	Direct to Large Int. Transport Energy
Bills	859,416	Direct to Residential Customer
	132,276	Direct to Firm General Customer
	36	Direct to Air Force Customer
	888	Direct to Small Int. Sales Customer
	864	Direct to Small Int. Transport Customer
	0	Direct to Large Int. Sales Customer
	108	Direct to Large Int. Transport Customer
Peak Day Dk Demand	114,254	Direct to Residential Demand
	78,014	Direct to Firm General Demand
	0	Direct to Air Force Demand
	0	Direct to Small Int. Sales Demand
	0	Direct to Small Int. Transport Demand
	0	Direct to Large Int. Sales Demand
	0	Direct to Large Int. Transport Demand

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		Total	Residential			Firm General			Air Force		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput	17,937,951		7,681,994			5,470,992			1,018,005	
		100.000001%	0.000000%	42.825371%	0.000000%	0.000000%	30.499537%	0.000000%	0.000000%	5.675147%	0.000000%
2.	2-Day Peak Sales	193,871	115,109			78,762			0		
		100.000000%	59.374017%	0.000000%	0.000000%	40.625983%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
3.	Dk Sales	14,660,691		7,681,994			5,470,992			1,018,005	
		100.000000%	0.000000%	52.398581%	0.000000%	0.000000%	37.317422%	0.000000%	0.000000%	6.943772%	0.000000%
4.	Dk Throughput @ Distribution	15,194,988		7,541,319			5,347,943			145,706	
		100.000000%	0.000000%	49.630306%	0.000000%	0.000000%	35.195441%	0.000000%	0.000000%	0.958908%	0.000000%
5.	2-Day Peak @ Distribution	192,268	114,254			78,014			0		
		100.000000%	59.424345%	0.000000%	0.000000%	40.575655%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
8.	Average Customers	82,799			71,618			11,023			3
		100.000001%	0.000000%	0.000000%	86.496214%	0.000000%	0.000000%	13.312963%	0.000000%	0.000000%	0.003623%
9.	Average Customers @ Distribution	81,502			70,495			10,858			2
		99.999999%	0.000000%	0.000000%	86.494810%	0.000000%	0.000000%	13.322372%	0.000000%	0.000000%	0.002454%
10.	Wtd. Customers @ Distrib. Excl. AF & LI	127,464			70,495			54,290			
		100.000000%	0.000000%	0.000000%	55.305812%	0.000000%	0.000000%	42.592418%	0.000000%	0.000000%	0.000000%
11.	Average Res. & Firm General Cust.	82,641			71,618			11,023			
		100.000000%	0.000000%	0.000000%	86.661584%	0.000000%	0.000000%	13.338416%	0.000000%	0.000000%	0.000000%
12.	Weighted Customers @ Distribution	127,464			70,495			54,290			0
		100.000000%	0.000000%	0.000000%	55.305812%	0.000000%	0.000000%	42.592418%	0.000000%	0.000000%	0.000000%
13	Distribution Mains	27,079,883	8,046,022	6,719,914	0	5,493,920	4,765,442	0	0	129,836	0
		100.000001%	29.712174%	24.815152%	0.000000%	20.287828%	17.597720%	0.000000%	0.000000%	0.479456%	0.000000%
15.	Distribution Plant	55,450,251	8,709,421	7,273,977	14,232,418	5,946,899	5,158,356	11,023,059	0	140,543	111,829
		100.000001%	15.706730%	13.118024%	25.667004%	10.724747%	9.302674%	19.879187%	0.000000%	0.253458%	0.201674%
16.	Meters & Regulators	13,660,556	0	0	7,526,766	0	0	5,821,704	0	0	0
		100.000000%	0.000000%	0.000000%	55.098533%	0.000000%	0.000000%	42.616889%	0.000000%	0.000000%	0.000000%

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		Small Interruptible Sales			Small Interruptible Transport			Large Interruptible Sales			Large Interruptible Transport		
		Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput		489,700			1,030,440			0			2,246,820	
		0.000000%	2.729966%	0.000000%	0.000000%	5.744469%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	12.525511%	0.000000%
2.	2-Day Peak Sales	0			0			0			0		
		0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
3.	Dk Sales		489,700						0				
		0.000000%	3.340225%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
4.	Dk Throughput @ Distribution		474,400			918,000			0			767,620	
		0.000000%	3.122082%	0.000000%	0.000000%	6.041466%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	5.051797%	0.000000%
5.	2-Day Peak @ Distribution	0			0			0			0		
		0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
8.	Average Customers			74			72			0			9
		0.000000%	0.000000%	0.089373%	0.000000%	0.000000%	0.086958%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.010870%
9.	Average Customers @ Distribution			72			69			0			6
		0.000000%	0.000000%	0.088341%	0.000000%	0.000000%	0.084660%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.007362%
10.	Wtd. Customers @ Distrib. Excl. AF & LI			1,368			1,311						
		0.000000%	0.000000%	1.073244%	0.000000%	0.000000%	1.028526%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11.	Average Res. & Firm General Cust.												
		0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12.	Weighted Customers @ Distribution			1,368			1,311			0			0
		0.000000%	0.000000%	1.073244%	0.000000%	0.000000%	1.028526%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Distribution Mains	0	422,728	0	0	818,011	0	0	0	0	0	684,010	0
		0.000000%	1.561041%	0.000000%	0.000000%	3.020733%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	2.525897%	0.000000%
15.	Distribution Plant	0	457,581	287,084	0	885,458	295,402	0	0	0	0	740,405	187,819
		0.000000%	0.825210%	0.517733%	0.000000%	1.596851%	0.532733%	0.000000%	0.000000%	0.000000%	0.000000%	1.335260%	0.338716%
16.	Meters & Regulators	0	0	152,635	0	0	155,855	0	0	0	0	0	3,596
		0.000000%	0.000000%	1.117341%	0.000000%	0.000000%	1.140913%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.026324%

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		Total	Residential			Firm General			Air Force		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
17.	Structures & Improvements	180,116	38,113	31,832	0	26,024	22,573	4,218	0	615	13,406
		100.000000%	21.160252%	17.673055%	0.000000%	14.448467%	12.532479%	2.341824%	0.000000%	0.341447%	7.442981%
18.	Meas. & Reg. Sta. Eqpt.- General	520,093	153,254	127,996	0	104,644	90,768	0	0	2,473	4,297
		100.000000%	29.466653%	24.610214%	0.000000%	20.120248%	17.452263%	0.000000%	0.000000%	0.475492%	0.826198%
19.	Meas. & Reg. Eqpt.- City Gate	174,002	46,773	39,065	0	31,938	27,703	6,887	0	755	0
		99.999999%	26.880726%	22.450891%	0.000000%	18.354961%	15.921081%	3.958000%	0.000000%	0.433903%	0.000000%
20.	Service Regulators	1,677,415	0	0	899,393	0	0	717,794	0	0	0
		100.000000%	0.000000%	0.000000%	53.617799%	0.000000%	0.000000%	42.791676%	0.000000%	0.000000%	0.000000%
21.	Ind. Meas. & Reg. Sta. Eqpt.	371,028	27,148	22,674	0	18,537	16,079	26,056	0	438	94,126
		100.000000%	7.316968%	6.111129%	0.000000%	4.996119%	4.333635%	7.022651%	0.000000%	0.118050%	25.368975%
22.	Mains & Services	39,204,561	8,046,022	6,719,914	6,705,652	5,493,920	4,765,442	5,164,194	0	129,836	0
		99.999999%	20.523178%	17.140643%	17.104265%	14.013472%	12.155325%	13.172432%	0.000000%	0.331176%	0.000000%
23.	Sales & Transportation Rev.	95,126,405	18,016,893	29,032,671	5,370,088	12,302,188	20,940,614	1,393,298	400,116	4,520,837	9,218
		100.000000%	18.939949%	30.520097%	5.645213%	12.932464%	22.013461%	1.464681%	0.420615%	4.752452%	0.009690%
24.	Net Gas Plant in Service	23,420,233	3,383,670	2,825,989	6,503,658	2,310,413	1,996,066	5,053,839	0	54,603	76,420
		99.999999%	14.447636%	12.066443%	27.769399%	9.865030%	8.522827%	21.578944%	0.000000%	0.233145%	0.326299%
25.	Total Gas Plant in Service	69,314,220	10,889,845	9,095,033	17,790,014	7,435,720	6,441,773	13,778,431	0	175,729	139,782
		99.999999%	15.710838%	13.121453%	25.665749%	10.727553%	9.293581%	19.878217%	0.000000%	0.253525%	0.201664%
26.	Sales Revenue	100,274,418	19,231,623	30,990,104	5,732,149	13,131,623	22,352,466	1,487,237	427,093	4,825,640	9,840
		100.000000%	19.178992%	30.905294%	5.716462%	13.095686%	22.291295%	1.483167%	0.425924%	4.812434%	0.009813%
27.	All Other Dist. Operation Exp.	2,305,201	195,571	163,337	893,535	133,538	115,831	692,124	0	3,155	9,779
		99.999999%	8.483902%	7.085586%	38.761696%	5.792900%	5.024768%	30.024453%	0.000000%	0.136864%	0.424215%
28.	All Other Dist. Maintenance Exp.	367,550	42,942	35,865	121,079	29,322	25,433	93,775	0	693	1,373
		100.000001%	11.683308%	9.757856%	32.942185%	7.977690%	6.919603%	25.513536%	0.000000%	0.188546%	0.373555%
30.	O&M Excl. Gas Cost and A&G	8,632,614	458,651	413,324	4,744,601	313,174	293,201	2,123,546	0	11,410	21,447
		100.000002%	5.313003%	4.787936%	54.961348%	3.627800%	3.396434%	24.599108%	0.000000%	0.132173%	0.248442%

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		Small Interruptible Sales			Small Interruptible Transport			Large Interruptible Sales			Large Interruptible Transport		
		Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
17.	Structures & Improvements	0 0.000000%	2,002 1.111506%	0 0.000000%	0 0.000000%	3,875 2.151391%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	3,240 1.798841%	34,218 18.997757%
18.	Meas. & Reg. Sta. Eqpt.- General	0 0.000000%	8,052 1.548185%	0 0.000000%	0 0.000000%	15,581 2.995810%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	13,028 2.504937%	0 0.000000%
19.	Meas. & Reg. Eqpt.- City Gate	0 0.000000%	2,457 1.412053%	0 0.000000%	0 0.000000%	4,755 2.732727%	9,693 5.570626%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	3,976 2.285031%	0 0.000000%
20.	Service Regulators	0 0.000000%	0 0.000000%	24,027 1.432383%	0 0.000000%	0 0.000000%	32,605 1.943765%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	3,596 0.214377%
21.	Ind. Meas. & Reg. Sta. Eqpt.	0 0.000000%	1,426 0.384338%	4,322 1.164872%	0 0.000000%	2,760 0.743879%	5,149 1.387766%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	2,308 0.622055%	150,005 40.429563%
22.	Mains & Services	0 0.000000%	422,728 1.078262%	130,127 0.331918%	0 0.000000%	818,011 2.086520%	124,705 0.318088%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	684,010 1.744720%	0 0.000000%
23.	Sales & Transportation Rev.	209,126 0.219840%	1,704,474 1.791799%	29,215 0.030712%	0 0.000000%	538,661 0.566258%	80,410 0.084530%	0 0.000000%	11,185 0.011758%	843 0.000886%	0 0.000000%	495,568 0.520957%	71,000 0.074638%
24.	Net Gas Plant in Service	0 0.000000%	177,772 0.759053%	134,124 0.572684%	0 0.000000%	344,007 1.468845%	144,576 0.617312%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	287,652 1.228220%	127,444 0.544162%
25.	Total Gas Plant in Service	0 0.000000%	572,138 0.825427%	358,845 0.517708%	0 0.000000%	1,107,134 1.597268%	369,242 0.532707%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	925,767 1.335609%	234,767 0.338700%
26.	Sales Revenue	223,226 0.222615%	1,819,393 1.814414%	31,185 0.031100%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	11,939 0.011906%	900 0.000898%	0 0.000000%	0 0.000000%	0 0.000000%
27.	All Other Dist. Operation Exp.	0 0.000000%	10,275 0.445731%	18,057 0.783316%	0 0.000000%	19,882 0.862484%	18,221 0.790430%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	16,626 0.721239%	15,270 0.662415%
28.	All Other Dist. Maintenance Exp.	0 0.000000%	2,256 0.613794%	2,453 0.667392%	0 0.000000%	4,365 1.187594%	2,459 0.669025%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	3,651 0.993334%	1,884 0.512583%
30.	O&M Excl. Gas Cost and A&G	0 0.000000%	26,026 0.301485%	47,745 0.553077%	0 0.000000%	50,687 0.587157%	47,732 0.552926%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	47,844 0.554224%	33,226 0.384889%

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		Total	Residential			Firm General			Air Force		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
31.	O&M Excl. Cost of Gas	12,722,671	675,956	609,153	6,992,552	461,553	432,117	3,129,664	0	16,816	31,608
		100.000000%	5.313004%	4.787933%	54.961352%	3.627800%	3.396433%	24.599111%	0.000000%	0.132174%	0.248438%
33.	Total Cost of Gas	77,058,145	19,231,623	23,078,733	0	13,131,623	16,436,303	0	427,093	3,058,355	0
		100.000001%	24.957288%	29.949765%	0.000000%	17.041188%	21.329741%	0.000000%	0.554248%	3.968893%	0.000000%
35.	Taxable Income	10,992,096	(2,507,907)	10,121,991	(2,966,041)	(1,712,449)	7,476,057	(2,702,063)	(27,106)	2,135,327	(29,321)
		100.000001%	-22.815549%	92.084267%	-26.983398%	-15.578912%	68.013025%	-24.581872%	-0.246595%	19.426022%	-0.266746%
38.	Customer Account Expense O&M	229,995	0	0	198,937	0	0	30,619	0	0	8
		99.999999%	0.000000%	0.000000%	86.496228%	0.000000%	0.000000%	13.312898%	0.000000%	0.000000%	0.003478%
39.	Distribution O&M	5,161,950	458,651	413,324	1,924,512	313,174	293,201	1,490,737	0	11,410	21,343
		99.999999%	8.885227%	8.007129%	37.282655%	6.066971%	5.680043%	28.879338%	0.000000%	0.221040%	0.413468%
40.	Dk Sales - Propane	46,755		17,184			29,571				
		100.000000%	0.000000%	36.753288%	0.000000%	0.000000%	63.246712%	0.000000%	0.000000%	0.000000%	0.000000%

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		Small Interruptible Sales			Small Interruptible Transport			Large Interruptible Sales			Large Interruptible Transport		
		Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
31.	O&M Excl. Cost of Gas	0	38,357	70,366	0	74,702	70,347	0	0	0	0	70,512	48,968
		0.000000%	0.301485%	0.553076%	0.000000%	0.587157%	0.552926%	0.000000%	0.000000%	0.000000%	0.000000%	0.554223%	0.384888%
33.	Total Cost of Gas	223,226	1,471,189	0	0	0	0	0	0	0	0	0	0
		0.289685%	1.909193%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
35.	Taxable Income	(14,167)	499,927	(65,728)	0	402,510	(14,841)	0	11,181	843	0	373,409	10,474
		-0.128884%	4.548059%	-0.597957%	0.000000%	3.661813%	-0.135015%	0.000000%	0.101719%	0.007669%	0.000000%	3.397068%	0.095287%
38.	Customer Account Expense O&M	0	0	206	0	0	200	0	0	0	0	0	25
		0.000000%	0.000000%	0.089567%	0.000000%	0.000000%	0.086958%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.010870%
39.	Distribution O&M	0	26,026	38,905	0	50,687	39,223	0	0	0	0	47,844	32,913
		0.000000%	0.504189%	0.753688%	0.000000%	0.981935%	0.759849%	0.000000%	0.000000%	0.000000%	0.000000%	0.926859%	0.637608%
40.	Dk Sales - Propane	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE (SMALL METERS)
ZONE 1

DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
0	$6.50	$11.70	$5.20	80.00%
1	10.43	15.04	4.61	44.20%
2	14.36	18.38	4.02	27.99%
3	18.30	21.72	3.42	18.69%
4	22.23	25.06	2.83	12.73%
5	26.16	28.40	2.24	8.56%
10	43.57	45.09	1.52	3.49%
15	60.97	61.79	0.82	1.34%
20	78.38	78.48	0.10	0.13%
25	95.78	95.18	(0.60)	-0.63%
30	113.19	111.87	(1.32)	-1.17%
35	130.59	128.57	(2.02)	-1.55%
40	148.00	145.26	(2.74)	-1.85%
45	165.40	161.96	(3.44)	-2.08%
50	182.81	178.65	(4.16)	-2.28%
60	217.62	212.04	(5.58)	-2.56%
70	252.43	245.43	(7.00)	-2.77%
80	287.24	278.82	(8.42)	-2.93%
90	322.05	312.21	(9.84)	-3.06%
100	356.86	345.60	(11.26)	-3.16%

PRESENT RATE 60: 1/		PROPOSED RATE 60: 2/	
Base Rate	$6.50	Basic Delivery Charge	$11.70
1st 5 dk	$3.932	Distribution Delivery	$0.432
Over 5 dk	$3.481	Cost of Gas	$2.907

1/ Rate effective March 1, 2002.
2/ Includes March 2002 Cost of Gas based on .45% loss factor plus surcharge & margin sharing.

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

Memo

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

To: Sandi Scott

From: Mike Diller MD

Date: September 5, 2002

Re: Case No. PU-399-02-183

Please docket attached documents evaluating the responses to our request for bid proposals related to the MDU gas case.

No copies are necessary. MD

51 **PU-399-02-183** Pages: 13

Evaluation of responses to request for bid proposals
by Public Service Commission

09/05/2002 CC: Comm Legal PUD (3) Mike ALJ .

Snavely King

Public Service Commission Evaluation Criteria
for
Request for Proposals/Competitive Negotiations

CASE No. PU-399-02-183

The following point system will be used in evaluating the proposals submitted. The individual criterion and point system was established in the written request for proposals. Each rater will use this form to score each proposal received and accepted. The total points of all raters will be added together and divided by the number of raters to establish the final score. All rating sheets will be kept as a part of the contract file.

1. Quality of written proposal (0-5) Points Awarded 4
   Comments, if any

2. Capability including personal qualifications, specialized experience, training, education, and performance record (0-20) Points Awarded 19
   Comments, if any

3. Understanding of the project (0-20) Points Awarded 18
   Comments, if any

4. Proposed work approach (0-10) Points Awarded 9
   Comments, if any

5. Price $48,534 (All Issues)

a.	Lowest bid to 120% =	45
b.	121% to 130% =	44
c.	131% to 140% =	42
d.	141% to 150% =	38
e.	151% to 160% =	32
f.	161% to 170% =	24
g.	171% to 180% =	14
h.	181% to 190% =	2
I.	191% and over =	0

Points Awarded 45

TOTAL POINTS AWARDED 95

SCORING SYSTEM

a.	Lowest bid to 120% =	45	$12,000 to $14,400
b.	121% to 130% =	44	$14,401 to $15,600
c.	131% to 140% =	42	$15,601 to $16,800
d.	141% to 150% =	38	$16,801 to $18,000
e.	151% to 160% =	32	$18,001 to $19,200
f.	161% to 170% =	24	$19,201 to $20,400
g.	171% to 180% =	14	$20,401 to $21,600
h.	181% to 190% =	2	$21,601 to $22,800
I.	191% and over =	0	

Larkin + Associates

Public Service Commission Evaluation Criteria
for
Request for Proposals/Competitive Negotiations

CASE No. PU-399-02-183

The following point system will be used in evaluating the proposals submitted. The individual criterion and point system was established in the written request for proposals. Each rater will use this form to score each proposal received and accepted. The total points of all raters will be added together and divided by the number of raters to establish the final score. All rating sheets will be kept as a part of the contract file.

1. Quality of written proposal (0-5) Points Awarded 5
   Comments, if any

2. Capability including personal qualifications, specialized experience, training, education, and performance record (0-20) Points Awarded 18
   Comments, if any

3. Understanding of the project (0-20) Points Awarded 18
   Comments, if any

4. Proposed work approach (0-10) Points Awarded 9
   Comments, if any

5. Price $49,500 (All Issues)

a.	Lowest bid to 120% =	45
b.	121% to 130% =	44
c.	131% to 140% =	42
d.	141% to 150% =	38
e.	151% to 160% =	32
f.	161% to 170% =	24
g.	171% to 180% =	14
h.	181% to 190% =	2
I.	191% and over =	0

Points Awarded 45

TOTAL POINTS AWARDED 95

SCORING SYSTEM

a.	Lowest bid to 120% =	45	$12,000 to $14,400
b.	121% to 130% =	44	$14,401 to $15,600
c.	131% to 140% =	42	$15,601 to $16,800
d.	141% to 150% =	38	$16,801 to $18,000
e.	151% to 160% =	32	$18,001 to $19,200
f.	161% to 170% =	24	$19,201 to $20,400
g.	171% to 180% =	14	$20,401 to $21,600
h.	181% to 190% =	2	$21,601 to $22,800
I.	191% and over =	0	

La Capra Associates

Public Service Commission Evaluation Criteria
for
Request for Proposals/Competitive Negotiations

CASE No. PU-399-02-183

The following point system will be used in evaluating the proposals submitted. The individual criterion and point system was established in the written request for proposals. Each rater will use this form to score each proposal received and accepted. The total points of all raters will be added together and divided by the number of raters to establish the final score. All rating sheets will be kept as a part of the contract file.

1. Quality of written proposal (0-5) Points Awarded 3
   Comments, if any

2. Capability including personal qualifications, specialized experience, training, education, and performance record (0-20) Points Awarded 17
   Comments, if any

3. Understanding of the project (0-20) Points Awarded 17
   Comments, if any

4. Proposed work approach (0-10) Points Awarded 6
   Comments, if any

5. Price $39,080 (Rate Band Cost of Service Rate Design) Other two issues:

			Snavely	Lakin
a.	Lowest bid to 120% =	45	11,400	8,500
b.	121% to 130% =	44	22,880	16,500
c.	131% to 140% =	42	34,280	25,000
d.	141% to 150% =	38		
e.	151% to 160% =	32		
f.	161% to 170% =	24		
g.	171% to 180% =	14		
h.	181% to 190% =	2		
i.	191% and over =	0		

ROR
Dep.

+ 25,000 for other two issues. Points Awarded 42

TOTAL POINTS AWARDED 85

64,080

Excluded based on price and quality of 2 ~~bids~~ low bids.

SCORING SYSTEM

a.	Lowest bid to 120% =	45	$12,000 to $14,400
b.	121% to 130% =	44	$14,401 to $15,600
c.	131% to 140% =	42	$15,601 to $16,800
d.	141% to 150% =	38	$16,801 to $18,000
e.	151% to 160% =	32	$18,001 to $19,200
f.	161% to 170% =	24	$19,201 to $20,400
g.	171% to 180% =	14	$20,401 to $21,600
h.	181% to 190% =	2	$21,601 to $22,800
I.	191% and over =	0	

Barrington-Wellesley Group

Public Service Commission Evaluation Criteria
for
Request for Proposals/Competitive Negotiations

CASE No. PU-399-02-183

The following point system will be used in evaluating the proposals submitted. The individual criterion and point system was established in the written request for proposals. Each rater will use this form to score each proposal received and accepted. The total points of all raters will be added together and divided by the number of raters to establish the final score. All rating sheets will be kept as a part of the contract file.

1. Quality of written proposal (0-5) Points Awarded _____
   Comments, if any

2. Capability including personal qualifications, specialized experience, training, education, and performance record (0-20) Points Awarded _____
   Comments, if any

3. Understanding of the project (0-20) Points Awarded _____
   Comments, if any

4. Proposed work approach (0-10) Points Awarded _____
   Comments, if any

5. Price $57,230 (Invest. + Cost of Service) + 34,000 Other Issues by Larkin

a.	Lowest bid to 120% =	45
b.	121% to 130% =	44
c.	131% to 140% =	42
d.	141% to 150% =	38
e.	151% to 160% =	32
f.	161% to 170% =	24
g.	171% to 180% =	14
h.	181% to 190% =	2
I.	191% and over =	0

Excluded from consideration as price exceeds low bid from reputable firm yet only includes 2 of 5 issues

Points Awarded 2

91,230

TOTAL POINTS AWARDED _____

Larkin
ROR 8,500
Dep. 16,500
R. Design 9,000
34,000

SCORING SYSTEM

a.	Lowest bid to 120% =	45	$12,000 to $14,400
b.	121% to 130% =	44	$14,401 to $15,600
c.	131% to 140% =	42	$15,601 to $16,800
d.	141% to 150% =	38	$16,801 to $18,000
e.	151% to 160% =	32	$18,001 to $19,200
f.	161% to 170% =	24	$19,201 to $20,400
g.	171% to 180% =	14	$20,401 to $21,600
h.	181% to 190% =	2	$21,601 to $22,800
I.	191% and over =	0	

GDS, Inc.

Public Service Commission Evaluation Criteria
for
Request for Proposals/Competitive Negotiations

CASE No. PU-399-02-183

The following point system will be used in evaluating the proposals submitted. The individual criterion and point system was established in the written request for proposals. Each rater will use this form to score each proposal received and accepted. The total points of all raters will be added together and divided by the number of raters to establish the final score. All rating sheets will be kept as a part of the contract file.

1. Quality of written proposal (0-5) Points Awarded _____
   Comments, if any

2. Capability including personal qualifications, specialized experience, training, education, and performance record (0-20) Points Awarded _____
   Comments, if any

3. Understanding of the project (0-20) Points Awarded _____
   Comments, if any

4. Proposed work approach (0-10) Points Awarded _____
   Comments, if any

5. Price $138,500 (All Issues)

a.	Lowest bid to 120% =	45
b.	121% to 130% =	44
c.	131% to 140% =	42
d.	141% to 150% =	38
e.	151% to 160% =	32
f.	161% to 170% =	24
g.	171% to 180% =	14
h.	181% to 190% =	2
I.	191% and over =	0

Excluded from consideration based on price.

Points Awarded 0

TOTAL POINTS AWARDED _____

SCORING SYSTEM

a.	Lowest bid to 120% =	45	$12,000 to $14,400
b.	121% to 130% =	44	$14,401 to $15,600
c.	131% to 140% =	42	$15,601 to $16,800
d.	141% to 150% =	38	$16,801 to $18,000
e.	151% to 160% =	32	$18,001 to $19,200
f.	161% to 170% =	24	$19,201 to $20,400
g.	171% to 180% =	14	$20,401 to $21,600
h.	181% to 190% =	2	$21,601 to $22,800
I.	191% and over =	0	

Investment
Cost of Cap
Cost of Service
Rate Design
Depreciation

Stone & Webster

Public Service Commission Evaluation Criteria
for
Request for Proposals/Competitive Negotiations

CASE No. PU-399-02-183

The following point system will be used in evaluating the proposals submitted. The individual criterion and point system was established in the written request for proposals. Each rater will use this form to score each proposal received and accepted. The total points of all raters will be added together and divided by the number of raters to establish the final score. All rating sheets will be kept as a part of the contract file.

1. Quality of written proposal (0-5) Points Awarded _____
   Comments, if any

2. Capability including personal qualifications, specialized experience, training, education, and performance record (0-20) Points Awarded _____
   Comments, if any

3. Understanding of the project (0-20) Points Awarded _____
   Comments, if any

4. Proposed work approach (0-10) Points Awarded _____
   Comments, if any

5. Price $170,750. (All Issues)

a.	Lowest bid to 120% =	45
b.	121% to 130% =	44
c.	131% to 140% =	42
d.	141% to 150% =	38
e.	151% to 160% =	32
f.	161% to 170% =	24
g.	171% to 180% =	14
h.	181% to 190% =	2
I.	191% and over =	0

Excluded from consideration based on price.

Points Awarded 0

TOTAL POINTS AWARDED _____

SCORING SYSTEM

a.	Lowest bid to 120% =	45	$12,000 to $14,400
b.	121% to 130% =	44	$14,401 to $15,600
c.	131% to 140% =	42	$15,601 to $16,800
d.	141% to 150% =	38	$16,801 to $18,000
e.	151% to 160% =	32	$18,001 to $19,200
f.	161% to 170% =	24	$19,201 to $20,400
g.	171% to 180% =	14	$20,401 to $21,600
h.	181% to 190% =	2	$21,601 to $22,800
I.	191% and over =	0	

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra L. Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **3rd day of September, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with first class postage, fully prepaid, securely sealed and each containing a photocopy of:

Order Granting Trade Secret Protection

The envelopes were addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

Cert. No. 7099 3220 0002 8482 2943

William P Pearce
Pearce & Durick
P O Box 400
Bismarck ND 58502-0400

Cert. No. 7099 3220 0002 8482 2950

Charles W King
Snavely King Majoros O'Connor & Lee Inc
1220 L Street NW, Suite 410
Washington DC 20005

Cert. No. 7099 3220 0002 8482 2967

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Notary Public

Subscribed and sworn to before me
this **3rd day of September 2002**.

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

50 **PU-399-02-183** Pages: 1

Affidavit of Service

by Public Service Commission

09/03/2002 CC: Comm Legal PUD (3) Mike ALJ .

Michael J. Majoros, Jr.

RECEIVED
AUG 30 2002
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

DIRECT TESTIMONY OF
MICHAEL J. MAJOROS, JR.

Introduction

Q. Please state your name, position and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 15 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 30-year history, members of the firm have participated in over 500 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes. Appendix A is a summary of my qualifications and experience. It also contains a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the staff of the North Dakota Public Service Commission.

EXHIBIT
19-49
PENGAD 800-631-6989

49 PU-399-02-183 Pages: 47
Direct Testimony of Michael J. Majoros, Jr.
by Snavely King Majoros O'Connor & Lee, Inc.
Exhibit # 19
08/30/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Objective of Testimony

Q. What is the objective of your testimony?

A. The objective of my testimony is to recommend the appropriate jurisdictional revenue requirement for the North Dakota Gas Division of Montana-Dakota Utilities Co. ("MDU"). By comparing this revenue requirement with the Company's 2003 pro forma revenues, I derive the indicated change in revenues which I believe is appropriate for the Company. The rate of return I use in these calculations has been provided by Charles W. King, whose testimony accompanies my own. Mr. King also discusses class revenue responsibilities and rate design.

Q. What was your approach to analyzing the Company's revenue requirement?

A. In this case the Company is seeking increases in its own net revenues, and these increases will be superimposed on those already resulting from the spikes in the market price of gas. My objective is to recognize the legitimate needs of the Company to cover its costs, but at the same time to ameliorate any added burden on ratepayers resulting from excessive recoveries. My modifications to the Company's rate proposals reflect my objectives.

Summary of Recommendations

Q. What base rate change has the Company requested in this case?

A. Witness Rita A. Mulkern proposes a $2.8 million base rate increase using an 11.44 percent rate of return.[1]

1 See Exhibit___(RAM-1).

Q. What base rate change do you recommend?

A. I recommend a $1.4 million base rate decrease using Mr. King's recommended 7.89% rate of return as quantified in my Exhibit ___ (MJM-1).

Q. What adjustments have you made to the Company's proposals?

A. I propose the following adjustments to the Company's revenue requirement request:

- I propose to reduce the Company's depreciation rates.
- I propose to eliminate the bonuses and commissions from the Company's costs and to hold the 2003 labor cost levels equal to the projected 2002 levels.
- I propose to eliminate the SISP from benefits expense.
- I propose a 5-year rather than 3-year rate case amortization period.
- I propose to eliminate the general inflation from other unadjusted operation and maintained expenses for an Other O&M expenses.
- I have used Mr. King's recommended capital cost rates.

Q. Do you have any exhibits to support your testimony?

A. Yes. I have several exhibits to support my testimony. As I explained, Exhibit ___ (MJM-1) quantifies my recommendation. I also compared it to the Company's proposal.

Financial Analyses

Q. Have you conducted any financial analyses?

A. Yes. My first financial analysis was to examine the gross margins reflected in the Company's case. The following table provides those margins as summarized from the Company's Statement N.

Gross Margins
2001-2003[2]
($000)

Description	2001	2002	2003
Total Revenues	$95,413	$69,131	$69,149
Total O&M	89,780	63,945	64,426
Gross Margin	$5,633	$5,186	$4,723

The gross margin analysis indicates that gross margins are projected to steadily decline from 2001 to the projected 2003 test year. Overall they decline by $910,000 from $5.6 million to $4.7 million.

My next analysis was to determine the cause of these declines. It was obvious by observation that the gross margins declined due to increases to operations and maintenance expenses excluding the cost of gas ("Other O&M"). The following table summarizes those expenses.

Other O&M
2001-2003
($000)

Description	2001	2002	2003
Other O&M	$12,938	$13,829	$14,354

2 Statement N, page 1.

The Other O&M increased by $1.4 million from $12.9 million to $14.4 million. Consequently, it can be reasonably concluded that increased Other O&M is a significant driver in the Company's request for additional revenues.

My next analysis analyzed the historical trends in Other O&M. These are shown on Exhibit___(MJM-2). The chart and table reveals that from 1996 to 2000, Other O&M increased from $12.1 million to $14.4 million. This reflects a compound growth rate of 2.5 percent, which may to some appear reasonable. However, closer inspection of the chart reveals that in 2001 Other O&M ratcheted up from 2000 and then the growth was smoothed from there. The compound growth rate from 2000 to 2003 is 5.7 percent. In my opinion, a 5.7 percent expense growth rate is not reasonable, even in the context of the 2.8 percent CPI growth rate cited by the Company in its filing.

Q. What was your next financial analysis?

A. Since I am recommending a decrease to the Company's depreciation rates, my next financial analysis deals with depreciation and cash flow.

Q. How does depreciation relate to cash flow?

A. For a public utility regulated on a rate base/rate of return basis, depreciation expense produces cash flow. That is because depreciation expense is a non-cash expense which is included in the revenue requirement. The Company collects the depreciation in rates, but there is no corresponding out flow.

Q. What does the Company do with this cash flow?

A. The cash flow is available for dividends, plant additions, investments in unregulated

companies or whatever the Company chooses.

Q. Is depreciation intended to finance plant additions?

A. No. The purpose of depreciation is to provide capital recovery. Depreciation is not, nor was it ever intended to finance plant additions. Many companies, however, attempt to make the case that depreciation is intended to finance additions. Consequently, I have made certain historical comparisons of depreciation to plant additions.

My first comparison is at the total MDU level. It compares total annual cash inflows from depreciation to total annual cash outflows for construction and acquisition of plant.[3]

Comparison of Annual Depreciation Cash InFlows To Construction Outflows - MDU 1996 – 2001

Year	Depreciation	Construction/ Acquistion	Incremental Cash Flow (2) – (3)
(1)	(2)	(3)	(4)=(2)-(3)
1996	$23,932	$21,796	$2,136
1997	24,505	24,545	(40)
1998	25,279	17,564	7,715
1999	25,725	21,102	4,623
2000	27,514	17,263	10,251
2002	28,824	25,036	3,788
Total	$155,779	$127,306	$28,473

Obviously the Company has derived substantial incremental cash flow from depreciation. In fact, it is financing all of its plant additions from depreciation funds it collects from ratepayers, and still has a substantial amount of additional cash for other matters.

Q. What was your next financial analysis?

3 From Statements of Changes in Financial Position from annual FERC Reports.

A. My next financial analyses was to determine if any of this incremental cash flow was being obtained from the North Dakota gas operations. For this analysis I focused on the depreciation and additions relating solely to North Dakota's gas distribution and general plant. I did not include any common or intangible plant. This analysis, included as Exhibit___(MJM-3) reveals that the Company has obtained substantial incremental cash flow as a result of depreciation charges to its North Dakota gas customers. In fact, since 1986, the Company has collected $4.5 million more in depreciation than it has added to North Dakota plant. It seems that ratepayers rather than investors have been financing the Company's North Dakota plant through excessive depreciation.

Excessive Depreciation

Q. What is excessive depreciation?

A. An excessive depreciation rate is one that produces depreciation expense more than necessary to return a company's capital investment in an asset over the life of the asset. In other words, since service lives and depreciation rates are inversely related, a life that is too short will result in a rate that is too high, thus producing excessive depreciation.

Q. Have any courts addressed the concept of excessive depreciation?

A. Yes, the concept of excessive depreciation was explained by the U.S. Supreme Court in a landmark 1934 decision, Lindheimer v. Illinois Bell Telephone Company, as follows:

> If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods.

> But if the amount charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.
>
> Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies of the 'behavior of large groups' of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting [are] always present. The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience.[4]

The Supreme Court found that excessive depreciation results in the extraction of capital contributions from ratepayers.

Q. Is this still relevant law?

A. Yes. In fact, it is cited in the NARUC Depreciation Manual which leads me to believe it is

4 Lindheimer v. Illinois Bell Telephone Company, 292 U.S. 151, 168-170, 54 S Ct. 658, 665-666 (1934). (Emphasis added; Footnote deleted).

relevant law.[5] I cite it here to demonstrate that there is clear precedent for the concept of excessive depreciation and its effect.

Q. What leads you to conclude the Company's existing depreciation rates are excessive?

A. I conclude the Company's existing depreciation rates are excessive for several reasons. First, the Company's depreciation reserve (accumulated depreciation) is excessive. The following table compares accumulated depreciation to the plant balances by function at December 31, 2001.

Comparison of Depreciation Reserves
To Plant In-Service
Gas Utility North Dakota
December 31, 2001
($000)

Function	Plant In Service [6]	Reserve [7]	Reserve %
Distribution	$55,087	$38,958	70.7
General	6,927	3,498	50.5
Common	5,178	2,593	50.1
Total	$67,192	$45,049	67.0%

Based on my experience the reserves shown above, particularly the distribution reserve, are extraordinarily high. That suggests that prior depreciation rates have been excessive.

Q. Has the Company conducted any studies to measure the adequacy or levels of its current

5 National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices, August 1996 ("NARUC Manual"), p. 13.

6 Response to DR 1-2, p. 24.

7 Statement D, p. 1 of 2.

depreciation reserves?

A. No. According to the Company, "no specific studies have been prepared regarding the adequacy of the depreciation reserve or calculation of any theoretical depreciation reserves."[8]

Q. Why are the Company's depreciation reserves so high?

A. The Company's current depreciation rates are based on a 1991 depreciation study conducted by Stone & Webster.[9] Exhibit___(MJM-4) is a summary page from the Stone & Webster study. My first reaction to the Stone & Webster study is that the cost of removal factor for Account 380-Services is extremely high. It is a negative 140 percent factor, which means that the current depreciation rate for Services was increased substantially to recover not only the existing investment, but also another 140 percent for future cost of removal. On its face this appears to be very excessive and undoubtedly contributes greatly to the excessive reserve ratios discussed above.

Q. Did any other factors cause you to conclude that the Company's depreciation rates may be excessive?

A. Yes. Another factor which caused me to conclude that the Company's depreciation rates may be excessive was the very short lives for Accounts 376-Mains and 380-Services; they are 36 years and 34 years, respectively. I have investigated gas depreciation rates on several occasions and based on my experience, these are extremely short service lives, thus pointing to excessive depreciation rates.

---

8 Response to Data Request No. 27.

9 See Statement I.

Q. Did you conduct any additional investigations concerning these lives and net salvage ratios?

A. Yes. I conducted Geometric Mean Turnover studies ("GMT") to test the lives for Mains and Services. These studies use the additions and retirements for the last five years to test service lives. The studies are attached as Exhibit __(MJM-5). The following table compares the results of these studies to the lives underlying the current depreciation rates.

Comparison of
GMT Life Indications
to Current Life Parameters

Account	Indicated Years	Current Life Years
376-Mains	108	36
380-Services	69	34

Obviously, the current depreciation rates are excessive because the underlying service lives are way too short.

Q. How did you test the net salvage ratios?

A. I reviewed the actual net salvage history included in Ms. Mulkern's workpapers. The workpapers and a summary of the most recent 5 years of actual experience are attached as Exhibit___(MJM-6).

Q. Do you have any general comments concerning the Company's overall net salvage experience?

A. Yes. Overall, the Company's experience is positive rather than negative. This is shown on Exhibit___ (MJM-6). The Company is collecting cost of removal from ratepayers, but

actually incurring positive net salvage. Furthermore, it appears that the Company has not recorded any net salvage at all for Services.

Q. Can you posit a reason that no net salvage is being recorded for Services?

A. Yes. Based on my experience, I have learned that many companies treat the costs associated with Services replacements as Service Transfer Expense i.e., no cost of removal is recorded. That may be why this Company does not record any net salvage for Services.

Q. What do you conclude?

A. I conclude that the Company's net salvage recovery is vastly overstated. In fact, it is recovering for negative net salvage, when in fact it is experiencing positive net salvage overall. It's ratepayers are being penalized. I disagree with the Company's cost of removal recovery.

Q. Are there any other reasons you disagree with the Company's cost of removal?

A. Yes. For all fiscal years beginning after June 15, 2002, all companies must determine whether or not they have actual legal obligations to retire their assets. These are called asset retirement obligations ("ARO"). If Companies do not have such obligations, these costs will likely be expensed under the terms of a recent AICPA Statement of Position on Property, Plant & Equipment. If ARO's do exist, they must be measured at their net present value, not the future inflated value. These requirements come under the auspices of Statement of Financial Accounting Standards ("SFAS") No. 143, which constitutes generally accepted accounting principles ("GAAP") for the public accounting profession. This Company is subject to SFAS No. 143.

Q. Does GAAP control ratemaking?

A. No. GAAP does not control ratemaking. However, the FERC is presently considering changes to the Uniform System of Accounts ("USOA") to account for the impact of SFAS No. 143. It is likely, therefore, that the principles underlying SFAS No. 143 will be reflected in the regulated accounting system.

Q. Why is SFAS No. 143 relevant in this proceeding?

A. The foundation of SFAS No. 143 makes sense. If a Company proposes to charge a future cost to current operations, it makes sense that it first establish the requirement to incur such a future cost. If such an obligation is established, it also makes sense for the obligation to be stated at its net present value to ensure that current operations are not charged with future inflation. The Company's approach is in conflict with these fundamental principles.

Q. Did you inquire about the company's implementation of SFAS No. 143?

A. The Company is unable to establish whether or not it has ARO's and even if it does, it has not established the net present value of these ARO's.[10] Although at the present time the Company is reviewing the scope of SFAS No. 143, there are no internal studies, research, relevant correspondence or accounting procedures at this time.[11]

Q. What do you recommend?

A. I recommend that the Commission recognize the fundamental principles of SFAS No. 143, by requiring that before any future costs of removal are included in current charges to

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10 Response to DRs 6 and 7, and Follow-up 2 and 3.

11 Id.

ratepayers, the Company must first establish that it has a legal obligation to incur those costs. Clearly, the Company's actual experience suggests that it does not have any such obligations. However, if the obligation to incur those costs is established, the costs should be measured at their net present value. In the meantime, I recommend the 5-year rolling average expensing approach used regularly by the Pennsylvania Public Utility Commission and recently approved in two cases by the Kentucky Public Service Commission.[12] This approach ensures that the Company recovers the net present value of its actual costs, but eliminates the inclusion of future inflation in depreciation rates. In my opinion, this approach is consistent in substance with the principles of SFAS No. 143.

Q. Have you calculated depreciation rates using your recommended approach?

A. Yes. The depreciation rates are shown on Exhibit__ (MJM-7). They merely recalculate the 1991 rates without net salvage. On page 3 I have calculated the year 2003 depreciation expense using these rates and then subtracted the average positive salvage the Company has actually experienced during the last five years.

Q. Do you consider these rates and this approach to be conservative?

A. Yes. These rates are still excessive because they are based on lives that are too short. They are conservative from the ratepayers perspective.

Labor Expenses

Q. Please explain your adjustment to Labor expense.

A. The Company proposes increase its labor expenses based on the use of an average

12 Kentucky Public Service Commission, Case Nos. 2000-373 and 2001-00244

commissions and bonuses for the 2001 to 2003 period. Presumably it makes this adjustment because the Commission required the use of an average bonus in the electric rate Case No. PO-399-01-186. In that case, the average bonus reduced the expense, as the Commission intended. In this proceeding, the use of an average bonus increases the 2003 amount because the projected bonus is less than the 2002 projected bonus.

Q. What do you recommend?

A. I recommend the elimination of the bonuses and commissions altogether. I have accepted the Company's proposed 2003 fully forecasted test year, however, in my opinion it is unreasonable to also project a bonus into that year rates. Although I am not an economist, it seems clear to me that we are in the midst of some type of recession. It is unreasonable to be granting bonuses, which in fact amounts to roughly half of the Company's overall requested increase, when the Company is proposing a rate increase to begin with.

Benefits Expense

Q. Please explain your adjustment to Benefit expense?

A. I am recommending disallowance of the SISP expense consistent with the Commissioner's decision in Case No. PU-399-01-186.

Rate Case Expense

Q. Please explain your adjustment to Rate Case Expense?

A. The Company proposes a 3-year amortization period. Given the period between rate cases, a 5-year amortization period appears more reasonable. Consequently, I recommend a 5-year amortization period.

Inflation to Other O&M Expenses

Q. Please explain your adjustment to Other O&M expenses.

A. The Company proposes to inflate those amounts by 2.8 percent. Apparently the Commission has never allowed such an adjustment in the past.[13] I do not recommend that it start now, consequently I have eliminated the 2.8 percent increase

Q. Have you summarized your O&M expense adjustments?

A. Yes. They are summarized in Exhibit __ (MJM-8), which is followed by individual detailed adjustments. Exhibit __ (MJM-9) shows the labor expense adjustment including a related adjustment to payroll taxes. Exhibit __ (MJM-10) show the elimination of the SISP from Benefits expenses. Exhibit __ (MJM-11) shows the revised amortization period for rate case expenses. Finally, Exhibit __ (MJM-12) shows the elimination of the general inflation factor to other OTM expenses.

Q. Does this conclude your testimony?

A. Yes, it does.

13 Response to Data Request No. 45.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water and sewerage companies. Mr. Majoros has appeared before Federal and state agencies. His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice.

Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. He has also developed the firm's capabilities in the management audit area.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros performed various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company). In addition, he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM80-42.

Handling Equipment Sales Company, Inc., *Treasurer (1976-1978)*

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RR79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority

State Regulatory Agencies

1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Electric Power Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Surban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest

Michael J. Majoros, Jr.

1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan

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1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Vermont	6596	Citizen's Energy Services

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate
2/ West Virginia Consumer Advocate
3/ Pennsylvania OCA
4/ Florida Office of Public Advocate
5/ Toms River Fire Commissioner's
6/ Iowa Office of Consumer Advocate
7/ D.C. People's Counsel
8/ Maryland's People's Counsel
9/ Idaho Public Service Commission
10/ Western Burglar and Fire Alarm
11/ U.S. Dept. of Defense
12/ N.M. State Corporation Comm.
13/ City of Philadelphia
14/ Resorts International
15/ Woodlake Condominium Association
16/ Illinois Attorney General
17/ Mass Coalition of Municipalities
18/ U.S. Department of Energy
19/ Arizona Electric Power Corp.
20/ Kansas Corporation Commission
21/ Public Service Comm. – Nevada
22/ SC Dept. of Consumer Affairs
23/ Georgia Public Service Comm.
24/ Delaware Public Service Comm.
25/ Conn. Ofc. Of Consumer Counsel
26/ Arizona Corp. Commission
27/ AT&T
28/ AT&T/MCI
29/ IN Office of Utility Consumer Counselor
30/ Unitel (AT&T – Canada)
31/ Public Interest Advocacy Centre
32/ U.S. General Services Administration
33/ Michigan Attorney General
34/ New Mexico Attorney General
35/ Environmental Protection Agency Enforcement Staff
36/ Kentucky Attorney General
37/ North Dakota Public Service Commission
38/ Kansas Industrial Group
39/ City of Witchita
40/ Kansas Citizens' Utility Rate Board
41/ NIPSCO Industrial Group
42/ Hawaii Division of Consumer Advocacy
43/ Nevada Bureau of Consumer Protection
44/ Vermont Department of Public Service

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - NORTH DAKOTA
(000s)

	Company			Snavely King		
	Before Additional Revenue Requirements	Additional Revenue Requirements	Reflecting Additional Revenue Requirements	Before Additional Revenue Requirements	Additional Revenue Requirements	Reflecting Additional Revenue Requirements
Operating Revenues						
Sales	$ 67,962	$ 2,840	$ 70,802	$ 67,962	$ (1,402) 1/	$ 66,560
Transportation	900		900	900		900
Other	287		287	287		287
Total Revenues	69,149		71,989	69,149		67,747
Operating Expenses						
Operation and Maintenance						
Cost of Gas	50,072		50,072	50,072		50,072
Other O&M	14,354		14,354	13,109		13,109
Total O&M	64,426		64,426	63,181		63,181
Depreciation	3,261		3,261	1,089		1,089
Taxes Other Than Income	1,352		1,352	1,292		1,292
Current Income Taxes	(1,961)	1,125	(836)	(529)	(555) 2/	(1,084)
Deferred Income Taxes	1,612		1,612	1,612		1,612
Total Expenses	68,690		69,815	66,645		66,090
Operating Income	$ 459	$ 1,715	$ 2,174	$ 2,504	$ (847)	$ 1,657
Rate Base	$ 19,681		$ 19,681	$ 20,768		$ 20,768 3/
Rate of Return	2.332%		11.044%	12.057%		7.980%

1/ Operating Income * 1+(.3961/(1-.3961))
2/ Revenues * 39.61%
3/ See page 4.

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

	Company			Snavely King
		Projected		
	2001	2002	2003	2003
Operating Revenues				
Sales	$ 93,961	$ 67,944	$ 67,962	$ 67,962
Transportation	1,165	900	900	900
Other	287	287	287	287
Total Revenues	95,413	69,131	69,149	69,149
Operation Expenses				
Operation and Maintenance				
Cost of Gas	76,842	50,116	50,072	50,072
Other O&M	12,938	13,829	14,354	13,109
Total O&M	89,780	63,945	64,426	63,181
Depreciation	3,059	3,143	3,261	1,089
Taxes Other Than Income	1,226	1,313	1,352	1,292
Current Income Taxes	4,322	(3,067)	(1,961)	(529)
Deferred Income Taxes	(4,031)	2,961	1,612	1,612
Total Expenses	94,356	68,295	68,690	66,645
Operating Income	$ 1,057	$ 836	$ 459	$ 2,504
Average Rate Base	$ 19,954	$ 19,449	$ 19,681	$ 20,768
Rate of Return	5.297%	4.298%	2.332%	12.057%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
CALCULATION OF CURRENT INCOME TAXES
PROJECTED 2002-2003
(000s)

	Company		Snavely King
	Projected		
	2002	2003	2003
Operating Revenues			
Sales	$ 67,944	$ 67,962	$ 67,962
Transportation	900	900	900
Other	287	287	287
Total Revenues	69,131	69,149	69,149
Operation Expenses			
Operation and Maintenance			
Cost of Gas	50,116	50,072	50,072
Other O&M	13,829	14,354	13,109
Total O&M	63,945	64,426	63,181
Depreciation	3,143	3,261	1,089
Taxes Other Than Income	1,313	1,352	1,292
Total Operating Expenses	68,401	69,039	65,562
Gross Adjustments to Operating Income	730	110	3,587
Deductions and Adjustments to Book Income:			
Interest Expense	784	778	641
Preferred Dividend Paid	15	15	15
Other Tax Deductions	7,675	4,267	4,267
Total Adjustments to Taxable Income	8,474	5,060	4,923
Taxable Income	(7,744)	(4,950)	(1,336)
Federal and State Income Taxes @ 39.61%	$ (3,067)	$ (1,961)	$ (529)

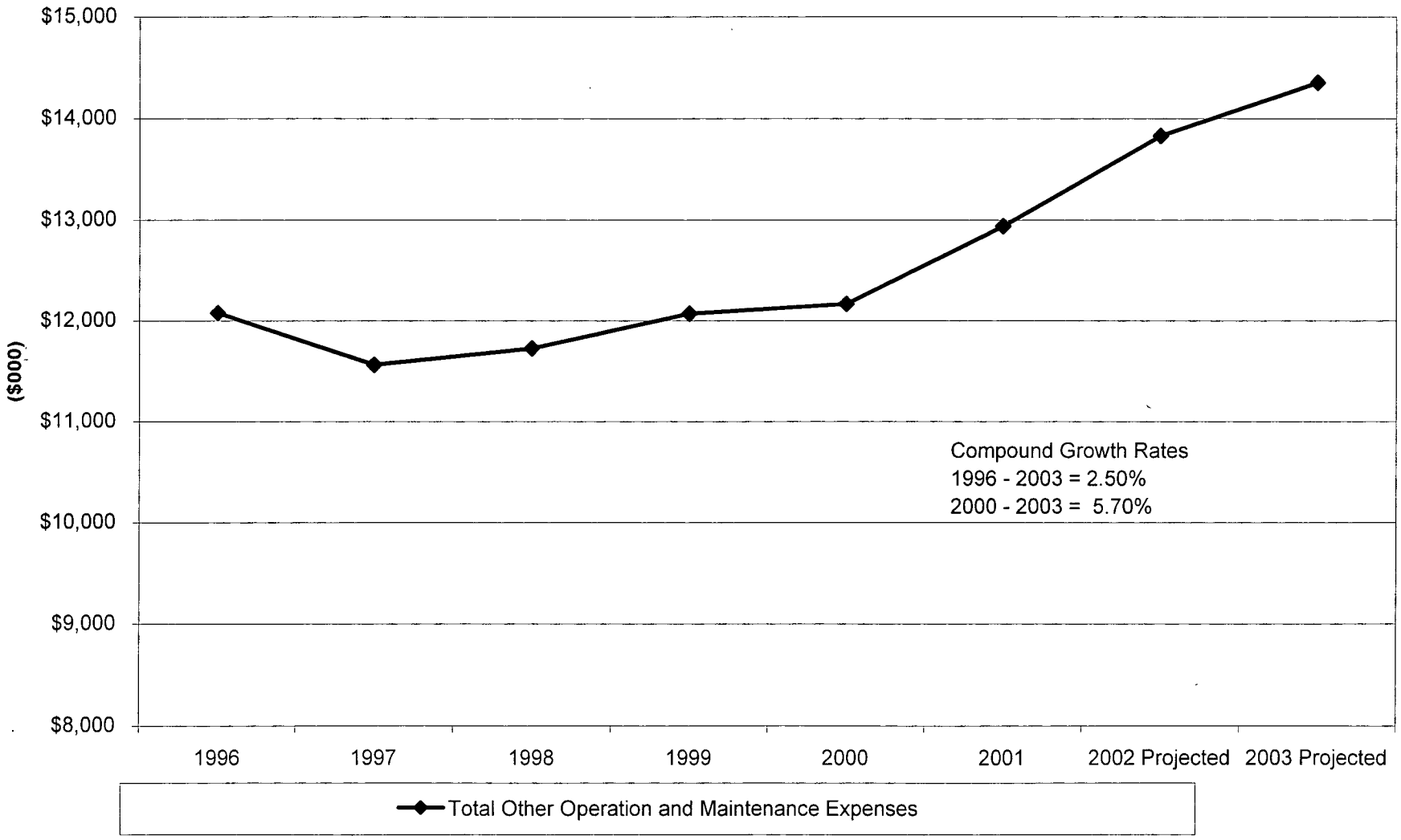
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
INTEREST EXPENSE ANNUALIZATION
PROJECTED 2002-2003
(000s)

	Company		Snavely King
	Projected		
	2002	2003	2003
Rate Base	$ 19,449	$ 19,681	$ 20,768 1/
Long Term Debt Ratio	43.61%	43.04%	
Long Term Debt Cost	9.24%	9.18%	
Weighted Cost of Debt	4.030%	3.951%	3.090% 2/
Interest Expense	$ 784	$ 778	$ 641

1/ $19,681 plus $1,086 (1/2 the $2,172 difference in depreciation expense) = $20,768

2/ CWK Testimony; long-term debt and short-term debt weighted cost rates.

Montana-Dakota Utilities Co. - North Dakota
Summary of Other Operation and Maintenance Expenses



Snavely King Majoros O'Connor & Lee, Inc.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OTHER OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - NORTH DAKOTA

	1996	1997	1998	1999	2000	2001	2002 Projected	2003 Projected
Other Gas Supply	$193,725	$192,058	$195,633	$197,261	$200,820	$215,821	$222,000	$228,000
Distribution	4,563,331	4,469,982	4,553,261	4,808,035	5,011,623	5,161,948	5,322,000	5,480,000
Customer Accounts	2,258,811	2,267,637	2,309,797	2,485,915	2,594,740	2,834,946	2,921,000	3,006,000
Customer Service & Infor.	87,390	94,450	99,916	114,901	150,091	165,360	179,000	182,000
Sales	545,462	424,041	373,606	469,858	475,069	470,362	429,000	441,000
Administrative and General	4,428,877	4,115,264	4,193,492	3,993,123	3,733,953	4,090,058	4,756,000	5,017,0
Total Other Operation and Maintenance Expenses 1/	$12,077,596	$11,563,432	$11,725,705	$12,069,093	$12,166,296	$12,938,495	$13,829,000	$14,354,0

1/ Includes Other Gas Supply Expense to conform to Statement N, p. 1.

Sources:
1996 - 2000 - Company response to Data Request No. 8, pages 38 and 39.
2001 - Company Statement H, page 1.
2002 - 2003 - Company Statement N, pages 4 and 5.

MONTANA-DAKOTA UTILITIES
GAS UTILITY - NORTH DAKOTA
COMPARISON OF DISTRIBUTION AND GENERAL
ADDITIONS AND DEPRECIATION EXPENSE
1986 - 2001

Year (1)	Depreciation Expense (2)	Additions (3)	Incremental Cash Flow (4) = (2) - (3)
1986	$ 1,640,833	$ 970,041	$ 670,792
1987	1,700,090	763,811	936,279
1988	1,729,344	1,054,487	674,857
1989	1,750,353	1,013,769	736,584
1990	1,780,765	1,193,070	587,695
1991	1,789,127	1,464,758	324,369
1992	1,868,853	1,652,392	216,461
1993	1,909,054	1,927,077	(18,023)
1994	2,129,765	2,311,487	(181,722)
1995	2,228,740	1,873,149	355,591
1996	2,286,011	2,743,247	(457,236)
1997	2,381,297	2,975,295	(593,998)
1998	2,463,133	2,205,886	257,247
1999	2,513,064	2,080,264	432,800
2000	2,584,318	2,287,542	296,776
2001	2,650,336	2,367,123	283,213
Total	$ 33,405,083	$ 28,883,399	$ 4,521,684

Sources:

Depreciation Expense - Company response to Data Request No. 29

1986 - 1999 Additions - Company response to Data Request No. 10.

2000 - 2001 Additions calculated using BOY and EOY balances from response to Data Request No. 8, p. 29 and retirements from response to Data Request No. 2, p. 20.

MONTANA DAKOTA UTILITY COMPANY
GAS PLANT
SUMMARY OF ANNUAL DEPRECIATION AMOUNTS AND RATES
UTILITY PLANT IN SERVICE AT DECEMBER 31,1991

CASE NO. _____
STATEMENT I
PAGE 3 OF 6

ACCOUNT NUMBER AND DESCRIPTION	PLANT BALANCE	EST. SALVAGE OR RETIREMENT PCT	COST AMOUNT	ESTIMATED SERVICE VALUE	MORT. DISPERS YRS	CRV	BOOK DEPR. RESERVE	UNRECOVERD SERVICE VALUE	EST. REM. LIFE	ANNUAL DEPRECIATION AMOUNT	PCT.
DISTRIBUTION PLANT											
374.2 LAND RIGHTS	72132			72132	FORECAST		34762	37370	20.1	1859	2.58
375 STRUCTURES AND IMPROVEMENTS	364728	-10	-36473	401201	39	R2	203226	197975	22.6	8760	2.40
376 DISTRIBUTION MAINS	51885311	-40	-20754124	72639435	36	R5	29073442	43565993	20.1	2167462	4.18
378 MEASURING AND REGULATING EQUIPMENT - GENERAL	1076163			1076163	33	R2.5	613745	462418	18.7	24728	2.30
379 MEASURING AND REGULATING EQUIP-CITY GATE	323078			323078	30	R0.5	160214	162864	18.4	8851	2.74
380 SERVICES	20072746	-140	-28101844	48174590	34	R3	12210080	35964510	21.8	1649748	8.22
381 METERS	19054646	10	1905465	17149181	33	R1.5	6598738	10550443	21.5	490718	2.58
383 HOUSE REGULATORS	2933282	10	293328	2639954	34	R1.5	1048699	1591255	22.9	69487	2.37
385 INDUSTRIAL MEASURING AND REGULATING EQUIPMENT	444153	20	88831	355322	35	R2.5	153853	201469	23.7	8501	1.91
387 OTHER EQUIPMENT	1200559			1200559	20	R2	356058	844501	13.5	62556	5.21
TOTAL	97426798		-46604817	144031615			50452817	93578798		4492670	4.61
GENERAL PLANT											
390 STRUCTURES AND IMPROVEMENTS	1781026	-5	-89051	1870077	36	R1.5	853464	1016613	24.4	41664	2.34
391 OFFICE FURNITURE AND EQUIPMENT	492877	5	24644	468233	17	S1	216720	251513	12.6	19961	4.05
393 STORES EQUIPMENT	134157			134157	39	R4	108291	25866	21.5	1203	0.90
394.1 TOOLS, SHOP & GARAGE EQUIPMENT	1566403	10	156640	1409763	20	R0.5	655173	754590	13.5	55896	3.57
394.3 VEHICLE MAINTENANCE EQUIPMENT	17674			17674	25	S3	643	17031	22.9	744	4.21
394.4 VEHICLE REFUELING EQUIPMENT	324491			324491	15	R2.5	-12195	336686	11.1	30332	9.35
395 LABORATORY EQUIPMENT	194819			194819	35	S2	65040	129779	28.7	4522	2.32
397.1 RADIO COMMUNICATION EQUIPMENT -FIXED	314490			314490	24	R2	140147	174343	15.1	11546	3.67
397.3 GENERAL TELEPHONE COMMUNICATIONS EQUIPMENT	56555	5	2828	53727	15	R2.5	8864	44863	12.1	3708	6.56
397.5 SUPERVISORY AND TELEMETERING EQUIPMENT	112400			112400	12	L5	41976	70424	9.4	7492	6.67
397.6 COMMUNICATION EQUIPMENT - SCADA	29510			29510	14	SQ	9505	20005	4.5	4446	15.07
398 MISCELLANEOUS EQUIPMENT	93493	15	14024	79469	35	S6	68563	10906	19.9	548	0.59
TOTAL	5117895		109085	5008810			2156191	2852619		182062	3.56
TOTAL DEPRECIABLE PLANT	102544693		-46495732	149040425			52609008	96431417		4674732	4.56

MONTANA DAKOTA UTILITY COMPANY
COMMON PLANT
SUMMARY OF ANNUAL DEPRECIATION AMOUNTS AND RATES
UTILITY PLANT IN SERVICE AT DECEMBER 31,1991

CASE NO. ____
STATEMENT I
PAGE 4 OF 6

ACCOUNT NUMBER AND DESCRIPTION		PLANT BALANCE	EST. SALVAGE OR RETIREMENT COST PCT	AMOUNT	ESTIMATED SERVICE VALUE	MORT. DISPERS YRS	CRV	BOOK DEPR. RESERVE	UNRECOVERD SERVICE VALUE	EST. REM. LIFE	ANNUAL DEPRECIATION AMOUNT	PCT.
	GENERAL PLANT											
390	STRUCTURES AND IMPROVEMENTS	15187083	-10	-1518708	16705791	35	S5	3789606	12916185	22.6	571513	3.76
391	OFFICE FURNITURE AND EQUIPMENT	3575250	15	536287	3038963	28	R0.5	1969838	1069125	20.2	52927	1.48
394.3	TOOLS, SHOP & GARAGE EQUIPMENT	33440			33440	25	S3	3721	29719	19.9	1493	4.46
394.4	TOOLS, SHOP & GARAGE EQUIPMENT	448613			448613	15	R2.5	48324	400289	10.6	37763	8.42
397.1	FIXED RADIOS	573054			573054	24	R2	218472	354582	14.3	24796	4.33
397.2	MOBILE RADIOS	1203656			1203656	16	R3	617116	586540	7.3	80348	6.68
397.3	TELEPHONE COMMUNICATION EQUIPT	263485	5	13174	250311	15	R2.5	51588	198723	7.1	27989	10.62
397.5	SUPERVISORY AND TELEMETERING EQUIPMENT	10015			10015	12	L5	9521	494	8.4	59	0.59
398	MISCELLANEOUS EQUIPMENT	364023	5	18201	345822	18	R2	253703	92119	10.1	9121	2.51
	TOTAL	21658619		-951046	22609665			6961889	15647776		806009	3.72
	TOTAL DEPRECIABLE PLANT	21658619		-951046	22609665			6961889	15647776		806009	3.72
	OTHER PROPERTY											
389	LAND	1432010						0				
391.1	COMPUTER EQUIPMENT	5234972						3042402				
392	TRANSPORTATION EQUIPMENT	9189325						6019667				
303	FRANCHISES AND CONSENTS	101280						0				
	TOTAL	15957587						9062069				
	TOTAL UTILITY PLANT	37616206						16023958				

Montana-Dakota Utilities Co. - North Dakota

Geometric Mean Turnover Analysis

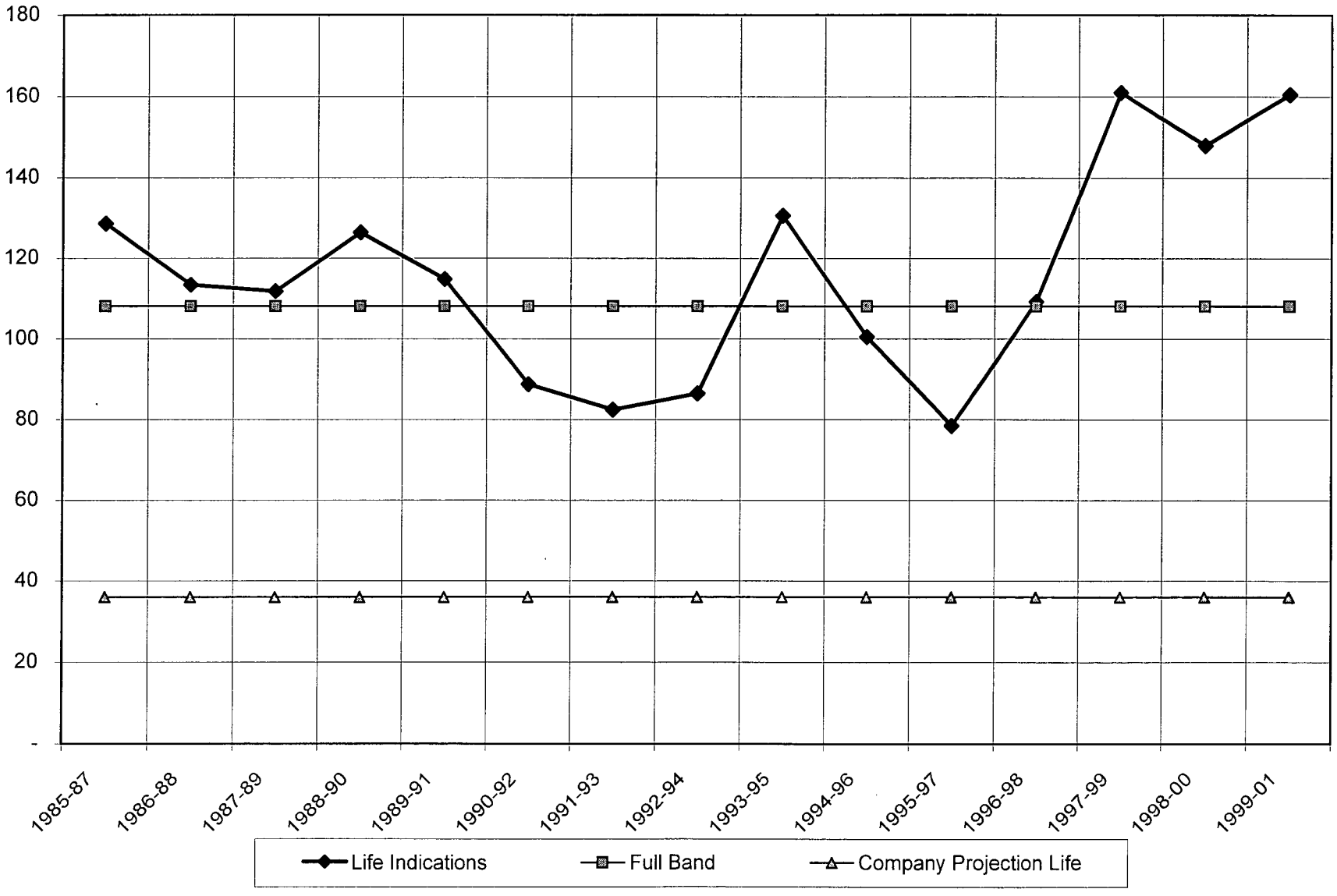
Account 376 - Mains

									3 Year Band					
Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	Avg. Plant Balance	Additions	Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate
	a	b=(a+prev a)/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1985	18,780,327	N/A	474,801	42,916										
1986	19,212,212	18,996,269	394,155	48,000	0.02075	0.00253	138.11							
1987	19,558,366	19,385,289	266,848	86,709	0.01377	0.00447	127.44	1985-87	38,381,558	661,003	134,709	0.01722	0.00351	128.62
1988	19,738,506	19,648,436	510,037	65,716	0.02596	0.00334	107.32	1986-88	39,033,725	776,886	152,424	0.01990	0.00390	113.43
1989	20,182,828	19,960,667	372,697	76,399	0.01867	0.00383	118.29	1987-89	39,609,103	882,734	142,115	0.02229	0.00359	11[illegible]
1990	20,479,126	20,330,977	444,200	47,959	0.02185	0.00236	139.30	1988-90	40,291,644	816,897	124,358	0.02027	0.00309	12[illegible]
1991	20,875,367	20,677,246	467,206	91,888	0.02260	0.00444	99.79	1989-91	41,008,223	911,406	139,847	0.02222	0.00341	114.87
1992	21,250,685	21,063,026	829,382	78,780	0.03938	0.00374	82.40	1990-92	41,740,272	1,296,588	170,668	0.03106	0.00409	88.73
1993	22,001,287	21,625,986	872,174	78,846	0.04033	0.00365	82.47	1991-93	42,689,012	1,701,556	157,626	0.03986	0.00369	82.43
1994	22,794,615	22,397,951	756,750	80,319	0.03379	0.00359	90.85	1992-94	44,023,937	1,628,924	159,165	0.03700	0.00362	86.46
1995	23,471,047	23,132,831	594,555	9,642	0.02570	0.00042	305.53	1993-95	45,530,782	1,351,305	89,961	0.02968	0.00198	130.59
1996	24,055,960	23,763,503	1,096,116	119,219	0.04613	0.00502	65.74	1994-96	46,896,334	1,690,671	128,861	0.03605	0.00275	100.47
1997	25,032,857	24,544,408	700,195	91,885	0.02853	0.00374	96.77	1995-97	48,307,911	1,796,311	211,104	0.03718	0.00437	78.45
1998	25,641,167	25,337,012	455,309	88,485	0.01797	0.00349	126.23	1996-98	49,881,420	1,155,504	180,370	0.02317	0.00362	109.26
1999	26,007,991	25,824,579	293,318	46,498	0.01136	0.00180	221.13	1997-99	51,161,591	748,627	134,983	0.01463	0.00264	160.94
2000	26,254,811	26,131,401	644,328	85,066	0.02466	0.00326	111.62	1998-00	51,955,980	937,646	131,564	0.01805	0.00253	147.93
2001	26,814,073	26,534,442	295,335	29,525	0.01113	0.00111	284.15	1999-01	52,665,843	939,663	114,591	0.01784	0.00218	160.50
1985 - 2001	382,151,224	359,354,024	9,467,406	1,167,850	0.02635	0.00325	108.07							

Sources: Company responses to Data Requests Nos. 2 and 10.

Company: Montana-Dakota Utilities Co. - ND
Account: 376
Category: Mains

Geometric Mean Rolling Band Analysis
Life Indications - Account 376 - Mains



Montana-Dakota Utilities Co. - North Dakota

Geometric Mean Turnover Analysis

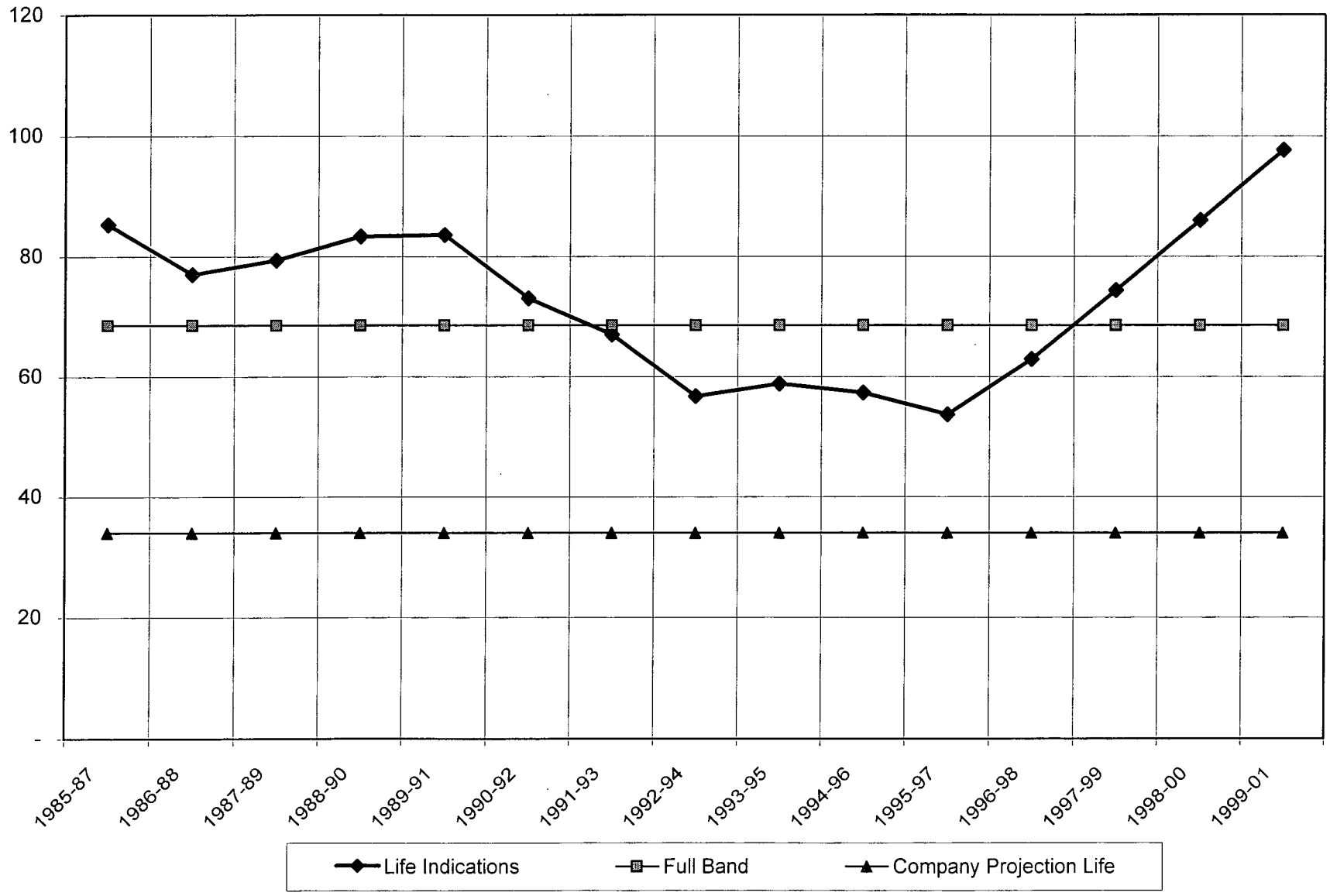
Account 380 - Services

									3 Year Band					
Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	Avg. Plant Balance	Additions	Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate
	a	b=(a+prev a)/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1985	7,393,465	N/A	316,440	32,872										
1986	7,677,033	7,535,249	245,045	22,522	0.03252	0.00299	101.43							
1987	7,899,556	7,788,294	248,375	42,782	0.03189	0.00549	75.55	1985-87	15,323,543	493,420	65,304	0.03220	0.00426	85.36
1988	8,105,149	8,002,352	257,548	40,346	0.03218	0.00504	78.50	1986-88	15,790,646	505,923	83,128	0.03204	0.00526	77.00
1989	8,322,351	8,213,750	245,279	42,650	0.02986	0.00519	80.31	1987-89	16,216,102	502,828	82,995	0.03101	0.00512	7
1990	8,524,981	8,423,666	237,720	39,812	0.02822	0.00473	86.59	1988-90	16,637,416	483,000	82,461	0.02903	0.00496	8
1991	8,722,889	8,623,935	252,518	44,953	0.02928	0.00521	80.94	1989-91	17,047,601	490,239	84,765	0.02876	0.00497	83.63
1992	8,930,455	8,826,672	277,931	62,678	0.03149	0.00710	66.88	1990-92	17,450,607	530,449	107,631	0.03040	0.00617	73.03
1993	9,145,708	9,038,081	302,772	59,744	0.03350	0.00661	67.20	1991-93	17,864,754	580,703	122,422	0.03251	0.00685	67.00
1994	9,388,736	9,267,222	456,259	77,407	0.04923	0.00835	49.31	1992-94	18,305,303	759,031	137,151	0.04147	0.00749	56.73
1995	9,767,587	9,578,162	404,949	41,810	0.04228	0.00437	73.61	1993-95	18,845,383	861,207	119,217	0.04570	0.00633	58.81
1996	10,130,726	9,949,156	464,213	91,796	0.04666	0.00923	48.20	1994-96	19,527,318	869,161	133,606	0.04451	0.00684	57.30
1997	10,503,142	10,316,934	457,193	62,906	0.04431	0.00610	60.84	1995-97	20,266,090	921,405	154,702	0.04547	0.00763	53.68
1998	10,897,429	10,700,286	395,971	67,997	0.03701	0.00635	65.21	1996-98	21,017,220	853,163	130,903	0.04059	0.00623	62.89
1999	11,225,403	11,061,416	311,083	53,208	0.02812	0.00481	85.98	1997-99	21,761,701	707,054	121,205	0.03249	0.00557	74.34
2000	11,483,278	11,354,340	403,227	41,783	0.03551	0.00368	87.48	1998-00	22,415,756	714,310	94,991	0.03187	0.00424	86.05
2001	11,844,722	11,664,000	315,390	35,434	0.02704	0.00304	110.34	1999-01	23,018,340	718,617	77,216	0.03122	0.00335	97.72
1985 - 2001	159,962,609	150,343,515	5,591,912	860,699	0.03719	0.00572	68.53							

Sources: Company responses to Data Requests Nos. 2 and 10.

Company: Montana-Dakota Utilities Co. - ND
Account: 380
Category: Services

Geometric Mean Rolling Band Analysis
Life Indications - Account 380 - Services



MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
CALCULATION OF FIVE-YEAR AVERAGE NET SALVAGE EXPERIENCE
TWELVE MONTHS ENDED DECEMBER 31, 2001

Year	Description	Salvage	Removal	Net Salvage	Net Salvage		
					Electric	Natural Gas	Common Utility
2001	Common Utility	4,905,677	16,641	4,889,037			4,889,037
2001	Electric	924,510	328,856	595,655	595,655		
2001	Natural Gas	528,464	87,760	440,703		440,703	
2000	Common Utility	90,868	33,319	57,549			57,549
2000	Electric	1,436,388	273,406	1,162,982	1,162,982		
2000	Natural Gas	190,282	67,530	122,752		122,752	
1999	Common Utility	27,425	7,655	19,770			19,770
1999	Electric	132,232	256,807	(124,574)	(124,574)		
1999	Natural Gas	485,174	111,081	374,093		374,093	
1998	Common Utility	549,402	(1,126)	550,528			550,528
1998	Electric	254,880	211,148	43,732	43,732		
1998	Natural Gas	180,060	100,376	79,685		79,685	
1997	Common Utility	60,096	47,719	12,377			12,377
1997	Electric	146,914	412,261	(265,347)	(265,347)		
1997	Natural Gas	488,278	61,060	427,218		427,218	
Total		10,400,651	2,014,492	8,386,160	1,412,448	1,444,452	5,529,260
Allocation of Common Utility (based on net salvage)					2,733,660	2,795,600	
Total Gas Utility						4,240,052	
Gas Utility 5-year Average Net Salvage						$ 848,010	

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
CALCULATION OF DEPRECIATION ACCRUALS
GAS UTILITY - NORTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Acct. No.	Account	Balance @ 12/31/00	Balance @ 12/31/01	Average Balance	Majoros Recommended Depreciation Rate	Annual Depreciation	To Clearing Accounts
	Distribution Plant						
374.1	Land	$41,687	$41,687	$41,687			
374.2	Rights of Way	42,598	44,836	43,717	2.58%	$1,128	
375	Structures & Improvements	180,117	180,117	180,117	1.96%	3,530	
376	Mains	26,814,073	27,079,883	26,946,978	2.19%	590,139	
378	Meas. & Reg. Equip.-General	514,232	520,093	517,163	2.30%	11,895	
379	Meas. & Reg. Equip.-City Gate	174,002	174,002	174,002	2.74%	4,768	
380	Services	11,844,722	12,124,678	11,984,700	1.80%	215,725	
381	Positive Meters	11,417,140	11,983,141	11,700,140	3.04%	355,684	
383	Service Regulators	1,635,648	1,677,415	1,656,532	2.81%	46,549	
385	Ind. Meas. & Reg. Station Eqpt.	369,866	371,028	370,447	2.76%	10,224	
386.1	Misc. Property on Cust. Premise	1,680	1,680	1,680	9.35%	157	
386.2	Other Property on Cust. Premise	113,207	113,207	113,207	9.35%	10,585	
387.1	Cathodic Protection Equip.	422,588	443,741	433,164	5.21%	22,568	
387.2	Other Distribution Equip.	331,598	331,598	331,598	5.21%	17,276	
	Total Distribution Plant	$53,903,158	$55,087,106	$54,495,132		$1,290,228	
	General Plant						
389	Land	$154,460	$154,460	$154,460			
390	Structures and Improvements	875,241	892,385	883,813	2.13%	18,825	
391.1	Furniture and Fixtures	220,644	216,111	218,378	4.45%	9,718	
391.3	Computer Equip. - PC	301,619	308,212	304,915	12.50%	38,114	
392.1	Trans. Equip., Non-Unitized	34,635	41,617	38,126	5.74% 2/		2,188
392.2	Trans. Equip., Unitized	1,988,947	2,052,922	2,020,935	5.74% 2/		116,002
393	Stores Equipment	74,396	74,396	74,396	0.90%	670	
394.1	Tools,Shop&Gar. Eq.-Non-Un.	1,053,692	1,084,749	1,069,220	4.31%	46,083	
394.2	Tools,Shop&Gar. Eq.-Unitized	123,956	123,956	123,956	4.83% 2/		5,987
394.3	Vehicle Maintenance Equip.	6,615	6,615	6,615	4.21%	278	
394.4	Vehicle Refueling Equip.	97,808	97,809	97,809	9.35%		9,145
395	Laboratory Equipment	110,077	119,514	114,795	2.32%		2,663
396.1	Power Operated Equip.	114,117	114,117	114,117	4.83% 2/		5,512
396.2	Work Equipment Trailers	1,268,061	1,317,959	1,293,010	4.83% 2/		62,452
397.1	Radio Comm. Equip.-Fixed	113,542	122,012	117,777	3.67%	4,322	
397.2	Radio Comm. Equip.-Mobile	98,837	98,837	98,837	3.67%	3,627	
397.3	General Tele. Comm. Equip.	28,055	28,055	28,055	6.97%	1,955	
397.5	Supervisory & Tele. Equip.	1,848	1,844	1,846	6.67%	123	
397.8	Network Equipment	10,599	11,308	10,954	12.50%	1,369	
398	Miscellaneous Equipment	59,571	60,179	59,875	1.34%	802	
	Total General Plant	$6,736,720	$6,927,057	$6,831,889		$125,886	$203,949
303	Intangible Plant - General	$195,788	$207,216	$201,502	2.19% 3/	4,413	
	Common Plant						
389	Land	$222,146	$208,685	$215,415			
390	Structures and Improvements	2,748,356	2,404,468	2,576,412	3.32%	85,537	
391.1	Furniture and Fixtures	506,882	449,917	478,400	2.22%	10,620	
391.2	Computer Equip.- Bull/AS400	11,141	11,535	11,338	15.55% 1/		
391.3	Computer Equip. - PC	577,050	509,396	543,223	12.50%	67,903	
391.5	Computer Equip. - Other	97,897	101,183	99,540	26.51% 1/		
392.1	Trans. Equip., Non-Unitized	34,284	36,269	35,277	5.74% 2/		2,025
392.2	Trans. Equip., Unitized	567,625	598,300	582,962	5.74% 2/		33,462
392.3	Aircraft	122,196	126,521	124,359	15.00% 2/		18,654
393	Stores Equipment	4,330	5,168	4,749	3.36%	160	
394.1	Tools, Shop & Gar. Equip.	33,905	38,118	36,011	3.44%	1,239	
394.3	Vehicle Maint. Equip.	14,508	15,170	14,839	4.46%	662	
394.4	Vehicle Refueling Equip.	103,617	111,753	107,685	8.42%	9,067	
396.2	Work Equipment Trailers	18,819	21,680	20,250	4.83% 2/		978
397.1	Radio Comm. Equip.-Fixed	87,804	89,113	88,458	4.33%	3,830	
397.2	Radio Comm. Equip.-Mobile	158,078	163,356	160,717	6.68%	10,736	
397.3	General Tele. Comm. Equip.	93,699	98,802	96,251	11.33%	10,905	
397.5	Supervisory & Tele. Equip.	570	10,166	5,368	0.59%	32	
397.8	Network Equipment	102,956	99,548	101,252	12.50%	12,657	
398	Miscellaneous Equipment	78,444	79,145	78,794	3.00%	2,364	
	Total Common Plant	$5,584,307	$5,178,293	$5,381,300		$215,712	$55,119
303	Intangible Plant - Common	1,724,072	$1,813,895	1,768,983	10.21% 3/	180,613	
386.3	Gas Plant Leased to Others	11,374	11,374	11,374	9.35%	1,063	
114.2	Acquisition Adjustment	97,266	$97,266	97,266		2,819	
	Total Gas Plant in Service	$68,252,685	$69,322,207	$68,787,446		$1,820,734	$259,068

1/ Fully depreciated.
2/ Charged to a clearing account.
3/ Amortized. Rate reflects annual amortization/plant.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF COMPOSITE DEPRECIATION RATES
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2001

	Average Plant	Majoros Recommended Annual Depreciation	%
Depreciation			
Distribution 1/	$54,506,506	$1,291,291	2.37%
General			
Other	$3,355,862	$125,886	3.75%
Clearing Accounts	3,476,027	203,949	5.87%
Total General	$6,831,889	329,835	4.83%
Common			
Other	$4,618,452	215,712	4.67%
Clearing Accounts	762,848	55,119	7.23%
	$5,381,300	270,831	5.03%
	$66,719,695	$1,891,957	2.84%
Amortization			
General Intangible	$201,502	4,413	2.19%
Common Intangible	1,768,983	180,613	10.21%
Acquisition Adjustment	97,266	2,819	2.90%
	$2,067,751	$187,845	9.08%
Total Plant	$68,787,446	$2,079,802	3.02%

1/ Includes gas plant leased to others.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
DEPRECIATION EXPENSE
PROJECTED 2002-2003
(000s)

Company Proposal

Function	2001	Projected 2002 1/	Projected 2003 1/
Distribution	2,523	$ 2,608	$ 2,703
General	128	112	104
Intangible Plant - General	3	5	5
Common	220	214	217
Intangible Plant - Common	185	201	229
Acquisition Adjustment	-	3	3
Total	$ 3,059	$ 3,143	$ 3,261

Snavely King Recommendation

Function	2001	Projected 2002	Projected 2003
Distribution	$ 2,523	$ 1,329	$ 1,378
General	128	119	111
Intangible Plant - General	3	5	5
Common	220	208	211
Intangible Plant - Common	185	201	229
Acquisition Adjustment	-	3	3
Subtotal	$ 3,059	$ 1,865	$ 1,937
Amortization of Five-Year Net Salvage			(848)
Total Depreciation Expense			$ 1,089

MONTANA-DAKOTA UTILITIES CO.
OTHER OPERATION AND MAINTENANCE EXPENSE
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003
(000s)

Company Proposal

Function	Total	Labor	Benefits	Insurance	Advertising	Rate Case Expense	Energy Share	All Other O&M
Other Gas Supply	$ 228	$ 150						$ 78
Distribution	5,480	4,506						974
Customer Accounts	3,006	1,969						1,037
Customer Service & Information	182	107			60			15
Sales	441	356			-			85
Administrative & General	5,017	1,397	1,462	306	76	56	11	1,709
Total Other O&M	$ 14,354	$ 8,485	$ 1,462	$ 306	$ 136	$ 56	$ 11	$ 3,898

Snavely King Recommendation

Total Other O&M	$ 13,109	$ 7,736	$ 1,197	$ 306	$ 136	$ 34	$ 11	$ 3,689

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
LABOR EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

Company Proposal

			Projected	
	2001		2002 1/	2003 2/
Gas Supply	$	142	146	150
Distribution		4,241	4,375	4,506
Customer acct.		1,854	1,912	1,969
Customer Service & Info.		101	104	107
Sales		335	346	356
A&G		1,315	1,356	1,397
Total	$	7,988	$ 8,239	$ 8,485

1/ Reflects average 3.15% increase reflecting average 2000-2002 bonus.
2/ Reflects projected 3.0% increase effective January 1, 2003.

Snavely King Recommendation

		Projected 3/	
	2001	2002	2003
Total	$ 7,988	$ 7,736	$ 7,736

3/ Reduced by 6.1% to eliminate bonuses from 2002 and also eliminates arbitrary 3% increase.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
PAYROLL TAXES
PROJECTED 2002-2003
(000s)

Company Proposal

		Projected	
	2001	2002 1/	2003 1/
FICA	$ 580		
Federal & State Unemployment	8		
Total	$ 588	$ 662	$ 682

1/ Calculated based on 2001 ratio of payroll taxes to labor.

Snavely King Recommendation

		Projected 2/	
	2001	2002	2003
Total	$ 588	$ 622	$ 622

3/ Reduced by 6.1% due to elimination of 2002 bonuses.

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - NORTH DAKOTA
PROJECTED 2002-2003
(000s)

Company Proposal

	2001	Projected 2002	2003
Type of Tax			
Ad Valorem			
Distribution	$ 489	$ 503	$ 522
General	52	52	51
Common	60	59	60
Intangible	3	3	3
Total Ad Valorem Taxes	$ 604	$ 617	$ 636
O&M Related Taxes - Other			
FICA	580	662	682
Federal & State Employment	8		
Franchise	13	13	13
Delaware Franchise	21	21	21
Total O&M Related Taxes	622	696	716
Total Taxes Other Than Income	$ 1,226	$ 1,313	$ 1,352

Snavely King Recommendation

Total Ad Valorem Taxes	$ 604	$ 617	$ 636
Total O&M Related Taxes	622	656	656
Total Taxes Other Than Income	$ 1,226	$ 1,273	$ 1,292

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
BENEFITS EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2001
PROJECTED 2002-2003
(000s)

Company Proposal

		Projected	
	2001	2002	2003
Medical/Dental	$ 823	$ 814	$ 879
Pension Expense	(649)	(575)	(475)
Post-retirement	468	541	527
401-K	200	211	217
Workers Compensation	22	48	49
SISP	-	259	265
Total	$ 864	$ 1,298	$ 1,462

Snavely King Recommendation

		Projected 1/	
	2001	2002	2003
Medical/Dental	$ 823	$ 814	$ 879
Pension Expense	(649)	(575)	(475)
Post-retirement	468	541	527
401-K	200	211	217
Workers Compensation	22	48	49
Total	$ 864	$ 1,039	$ 1,197

1/ Reflects disallowance of SISP.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE CASE EXPENSE
PROJECTED 2002-2003
(000s)

Company Proposal

	2001	2002 1/	2003 1/
Rate Case Expense	$ 1	$ 56	$ 56

1/ Reflects three year amortization of rate case expense.

Snavely King Recommendation

	2001	2002 2/	2003 2/
Rate Case Expense	$ 1	$ 34	$ 34

2/ Reflects five year amortization of rate case expense.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ADJUSTMENT TO OTHER O&M FOR INFLATION
PROJECTED 2002-2003
(000s)

Company Proposal

Function	2001	Projected 2002 1/	2003 1/
Other Gas Supply	$ 74	$ 76	$ 78
Distribution	921	947	974
Customer Accounts	981	1,009	1,037
Customer Service & Info.	15	15	15
Sales	81	83	85
Administrative & General	1,617	1,662	1,709
Total Other O&M	$ 3,689	$ 3,792	$ 3,898

1/ Increase of 2.81%.

Snavely King Recommendation

Function	2001	Projected 2/ 2002	2003
Other Gas Supply	$ 74	$ 74	$ 74
Distribution	921	921	921
Customer Accounts	981	981	981
Customer Service & Info.	15	15	15
Sales	81	81	81
Administrative & General	1,617	1,617	1,617
Total Other O&M	$ 3,689	$ 3,689	$ 3,689

2/ Reflects no adjustment for inflation.

DIRECT TESTIMONY OF CHARLES W. KING

RECEIVED
AUG 30 2002
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 30-year history, members of the firm have participated in over 500 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

PENGAD 800-631-6989
EXHIBIT
15-48

48 PU-399-02-183 Pages: 87
Direct Testimony of Charles W King
by Snavely King Majoros O'Connor & Lee, Inc.
Exhibit # 15
08/30/2002 CC: Comm Legal Illona, Pat, Jerry Mike

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Advocacy Staff of the North Dakota Public Service Commission.

Q. WHAT SUBJECTS DOES YOUR TESTIMONY ADDRESS?

A. My testimony addresses four subjects. Part I develops the appropriate rate of return on the rate base associated with the North Dakota gas distribution activities of Montana-Dakota Utilities, Inc. ("MDU" or "the Company"). Part II discusses the class cost of service study submitted as Statement M and sponsored by MDU witness Tamie A. Aberle. Part III evaluates the rate design proposals made by witness Tamie Aberle and supported by witness Russell A. Feingold. Finally, Part IV addresses the alternative Distribution Delivery Stabilization Mechanism, presented by MDU witness Feingold.

PART I – RATE OF RETURN

Q. WHAT HAVE YOU FOUND TO BE THE APPROPRIATE RATE OF RETURN FOR THE COMPANY'S NORTH DAKOTA ELECTRIC OPERATIONS?

A. Based on the analyses presented in this testimony, I find that the appropriate rate of return on the Company's electric operations in North Dakota is **7.98 percent,** inclusive of a return to equity of **10.5 percent.**

Q. WHAT INFORMATION DID YOU EXAMINE IN PREPARING YOUR TESTIMONY ON RATE OF RETURN?

A. I began by reading the testimonies of MDU witnesses Craig Keller and J. Stephen Gaske and their associated exhibits and statements. I prepared a series of data requests to which the Company responded. These responses in turn prompted a further round of data requests to which the Company has since responded. I have also reviewed the rate of return portion of the Commission's April 24, 2002 decision in Case No. PU-399-01-186, which related to MDU's electric operations. Finally, I have conducted considerable independent research, which I will discuss in the course of this testimony.

Q. HOW WILL YOU STRUCTURE YOUR TESTIMONY ON RATE OF RETURN?

A. I will first discuss the capital structure of the Company, that is, the mix of debt, preferred stock and common equity. I will next quantify the cost of the Company's debt and preferred stock. I will then discuss the theory of return to equity, the methodology for estimating it, and my development of the equity return requirement of MDU. I will conclude by applying the respective cost rates to the components of the capital structure to develop the appropriate return to total capital.

A. CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE DOES MDU PROPOSE TO USE IN CALCULATING ITS OVERALL RATE OF RETURN?

A. MDU witness Gaske uses a capital structure consisting of 43.039 percent long-term debt, 4.622 percent preferred stock, and 51.687 percent common equity. This capital structure conforms with that presented on page 3 of Statement F, which presents the Company's projected capital structure for the year 2003.

Q. DO YOU AGREE WITH THIS CAPITAL STRUCTURE?

A. No, I do not. There are two objections to the Company's proposed capital structure. The first is that it is a projected capital structure. It is therefore effectively a creation of the Company that has no basis in any verifiable financial statements. The second is that it includes no short-term debt.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND USING?

A. I propose to use the latest actual capital structure available, which is that for the year 2001.

Q. WHY DO YOU OBJECT TO THE COMPANY'S EXCLUSION OF SHORT-TERM DEBT?

A. The makeup of the capital structure used to develop a rate of return on rate base should reflect the nature of that rate base. If the rate base consists solely of capital investments in plant and equipment that are financed by long-term debt, preferred stock and equity, then it might be appropriate to exclude short-term debt. However, the Company's rate base also consists of materials and supplies inventories, fuel stocks, and prepayments. These short-term capital commitments will be financed in part with short-term debt. For this reason, I believe it is appropriate to include short-term debt in the capital structure.

Q. WHAT WAS THE LONG-TERM DEBT DURING THE YEAR 2001?

A. MDU Statement A, page 2, shows that long-term debt was $173,843,965 on December 31, 2000 and $158,304,439 on December 31, 2001. The average for the year is $166,094,202.

Q. WHAT WAS THE SHORT-TERM DEBT DURING THE YEAR?

A. Exhibit _____(CWK-1) is part of a response to a data request that shows the quarterly amounts of short-term debt during 2001. The last page of this exhibit shows that the average amount of short-term debt outstanding during 2001 was $9,639,726.

Q. WHAT WAS THE AMOUNT OF PREFERRED STOCK DURING 2001?

A. Statements A and F identify preferred stock during the year as $16,450,000.

Q. WHAT WAS THE AMOUNT OF COMMON EQUITY DURING 2001?

A. Statement F shows that the Company's total equity is $997,932,340 of which $843,497,103 represents the "subsidiary portion." For purposes of this calculation I am accepting the Company's calculation of common equity as $154,435,237.

Q. WHAT IS MDU'S CAPITAL STRUCTURE?

A. MDU's capital structure for the year 2001 is as follows:

Table 1
MDU Capital Structure, 2001
($000)

Short-term Debt	$9,639,726	2.78%
Long-term Debt	166,094,202	47.92%
Preferred Stock	16,450,000	4.75%
Common Equity	154,435,237	44.55%
Total	$346,619,165	100.00%

B. THE COST OF DEBT AND PREFERRED STOCK

Q. WHAT DOES THE COMPANY CLAIM TO BE THE COST OF THE COMPANY'S LONG-TERM DEBT?

A. On Schedule F-1, page 1 of Statement F, the Company calculates its 2001 cost of long-term debt as 9.302 percent.

Q. IS THIS THE CORRECT COST OF THE COMPANY'S LONG-TERM DEBT?

A. No. This cost rate is the weighted average cost of the medium term secured notes and the pollution control refunding revenue bonds that represent only a portion of the long-term debt of the parent Company, MDU Resources Group, Inc. While the pollution control bonds are arguably related to the electric service activities of MDU Utilities Company, the funds raised by the secured notes are available to any of the subsidiary activities of the parent company.

Excluded from the Company's calculation of its long-term debt rate are $405.2 million in senior notes, $219.7 million in commercial paper, $25 million in a revolving line of credit, $11.8 million in term credit agreements, and $2.3 million in a pollution control note obligation.

Q. WHY HAS THE COMPANY EXCLUDED THESE OTHER COMPONENTS OF DEBT?

A. The Company claims that its parent, MDU Resources Group, incurred these components of debt on behalf of other subsidiaries than MDU Utilities Company.

Q. IS THIS A VALID REASON TO EXCLUDE THESE ELEMENTS OF DEBT FROM THE DEBT COST CALCULATION?

A. No. The funds raised by debt issues are fungible. Apparently, MDU Resources Group has applied its low-cost sources of debt to the non-regulated subsidiaries and has left the high-cost debt to be recovered from the regulated operations of

MDU Utilities Company. I regard this as an artifice to manipulate the regulatory system into covering high-cost debt without providing any recognition of the parent's lower-cost financing resources. For this reason, I recommend that all of the components of MDU Resources Group's long-term debt be included in the calculation of debt costs.

Q. WHAT IS THE COST OF LONG-TERM DEBT WHEN THESE MISSING COMPONENTS OF THE PARENT COMPANY'S PORTFOLIO ARE INCLUDED?

A. Exhibit_____(CWK-2) presents a calculation of the weighted average long-term debt cost as of December 31, 2001 as reported in the Company's Statement A, pages 11 and 12 and Statement F, Schedule F-1, page 4. It shows that the composite, weighted average cost of long-term debt is 6.167 percent.

Q. WHAT IS THE COST OF SHORT-TERM DEBT?

A. The final page of Exhibit_____(CWK-1) shows that the average cost of short-term debt during 2001 was 4.542 percent.

Q. WHAT IS THE COST OF PREFERRED STOCK?

A. MDU's Statement F shows that the cost of preferred stock is 4.63 percent.

C. THE COST OF EQUITY

Q. WHAT IS THE BASIS FOR FINDING A RATE OR RETURN TO THE EQUITY COMPONENT OF THE CAPITAL DEVOTED TO MDU'S GAS UTILITY OPERATIONS IN NORTH DAKOTA?

A. In its landmark Hope Natural Gas decision, the United States Supreme Court established the following standards for the return to equity that must be allowed a regulated public utility:

> ..the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[1]

It can be seen from this excerpt that there are essentially three standards for determining an appropriate return to equity. The first is the "comparable earnings" standard, that the earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks." The second is that they must be sufficient to assure "confidence in the financial integrity of the enterprise," and the third is that they must allow the utility to be able to attract capital.

Q. HOW CAN THE COMPARABLE EARNINGS STANDARD BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. There is a certain circularity to the comparable earnings standard because the competitive nature of the capital markets virtually ensures that the returns to all enterprises having corresponding risks are comparable with each other. Investors establish the price of each traded stock based on that stock's present and prospective earnings in comparison with the present and prospective earnings of all other stocks and other investments available to them. If the earnings of a firm are depressed, then investors will pay only a low price for that firm's stock. As a result, their return on the market value of that stock will be comparable to the return on the market value of the stock of other highly profitable companies which, as a consequence of their profitability, have been bid up to a very high price.

[1]Federal Power Commission et. al. vs. Hope Natural Gas Company, 320 U.S. 592, at 603.

Thus, if "return" is defined as the earnings of an equity investment relative to its current market price, then the comparable earnings test becomes a cipher. All returns are comparable with all other returns.

In public utility regulation the conventional procedure for resolving this circularity is to identify the required equity return based on the market value of a utility's stock. That return is combined with the cost of debt and preferred stock, using either the actual or a hypothetical minimum-cost capital structure. The blended return to total capital is then applied to a rate base reflective of the book value of the utility's investment. The book value is the accountant's quantification of the original cost of the utility's assets adjusted for ratepayer contributions such as deposits and deferred taxes. Under this procedure, the market price of a stock is used only to determine the return that investors expect from that stock. That expectation is then applied to the book value of the utility's investment to identify the level of earnings which regulation will allow the utility's common shareholders to recover.

Q. HOW CAN THE FINANCIAL INTEGRITY AND CAPITAL ATTRACTION STANDARDS BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. If the utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit. Investors would have no reason to shun such a utility in favor of other investment opportunities. Thus, if the comparable earnings test is met, then the financial integrity and capital attraction standards are met as well.

Q. IN SEEKING "ENTERPRISES OF COMPARABLE RISK," WHAT IS THE RELEVANT "RISK" FOR PURPOSES OF THIS INQUIRY?

A. The purpose of this inquiry is to find the cost of the equity capital of MDU that is devoted to providing regulated gas distribution service in North Dakota. The

relevant risk is therefore that associated with providing regulated gas distribution service.

This level of risk is not the same risk as that of MDU Resources Group, Inc., the parent corporation of the company that provides the gas distribution service at issue in this inquiry. That is because regulated utility service is a relatively small proportion of the total revenue and earnings of the parent corporation, and regulated gas distribution service is an even smaller proportion, as demonstrated in Table 2:

Table 2

MDU Resources Group, Inc.
Year Ended December 31, 2001
(Dollars in Millions)

Business Segment	Revenues		Operating Income	
Electric Retail	$168.8	7.6%	$38.7	14.2%
Natural Gas Distribution	255.4	11.5%	3.6	1.3%
Total Regulated	$424.2	19.1%	$42.3	15.5%
Utility Services	364.8		25.2	
Pipeline and Energy Services	531.1		30.4	
Natural Gas, Oil Production & Other	209.8		103.9	
Construction Materials and Mining	806.9		71.5	
Intersegment eliminations	(113.2)			
Total Company	$2,223.6	100.0%	$273.3	100.0%

Source: MDU Resources Group, Inc. 2001Annual Report to Stockholders, page 1.
Note: numbers may not add due to rounding.

Q. FOR PURPOSES OF THIS INQUIRY, WHAT TYPES OF ENTERPRISES HAVE COMPARABLE RISK TO MDU'S REGULATED RETAIL ELECTRIC SERVICE?

A. The enterprises likely to have business risks most comparable to MDU's gas distribution service are those engaged in the same business, that is, the distribution of natural gas to retail end-users.

One of the central difficulties of this inquiry is that the procedures for identifying the cost of equity capital require that we be able to analyze the market prices of traded stocks. This means that we must deal with stand-alone corporations whose stock is traded on public markets. We cannot look at subsidiaries, affiliates, divisions or sectors of larger companies.

For this inquiry, we must therefore find companies with traded stock whose market risk is driven principally by the earnings, both present and prospective, from providing regulated utility gas distribution service. If the risk driver is some other business, the company cannot be said to be comparable.

Since we are attempting to find a rate of return sufficient to maintain credit and attract capital, we cannot examine utilities that have poor credit ratings. Accordingly, I have established as a criterion for acceptability that the company must have an "investment grade" bond rating, which is defined as BBB or better from Standard & Poors and Baa or better from Moody's. The company must be of broadly comparable size to MDU Resources, meaning that must be a large corporation. I have established a criterion of $100 million or more in gross revenues. Finally, in order to have business risks comparable to MDU's gas distribution service, the company must derive a substantial majority of its revenue from gas distribution service.

Q. HAVE YOU IDENTIFIED SPECIFIC COMPANIES THAT YOU BELIEVE COMPARABLE TO MDU'S GAS DISTRIBUTION SERVICE?

Yes. Exhibit_____(CWK-3) shows the companies that are listed as gas distribution companies in Value Line's Investment Survey; have investment grade bonds and total operating revenues in excess of $100 million, and derive more than 75 percent of their revenue from gas distribution services.

These criteria yield the list of 11 gas distribution utilities presented on Exhibit___(CWK-3):

Atmos Energy Corp.
AGL Resources
Cascade Natural Gas Corp.
LaClede Group, Inc.
NICOR, Inc.
Northwest Natural Gas Co.
People's Energy Corp.
Piedmont Natural Gas Co.
South Jersey Industries, Inc.
Southwest Gas
WGL Holdings, Inc.

Q. HOW WILL YOU IDENTIFY THE MARKET-DETERMINED RATE OF RETURN TO THE EQUITY CAPITAL INVESTMENT IN YOUR BAROMETER GROUP OF GAS DISTRIBUTION COMPANIES?

A. I shall first apply the Discounted Cash Flow ("DCF") procedure, which I consider to be the most accurate test of a market return. I shall then consider the interest rate risk premium approach as a "sanity check" on my DCF results.

1. DISCOUNTED CASH FLOW PROCEDURE

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW PROCEDURE.

A. The basic premise of the Discounted Cash Flow ("DCF") procedure is that the market values each stock at the discounted present value of all future flows of cash that investors expect from purchasing that stock. The discount rate that equates those future cash flows with the market value of the stock is the investors' required rate of return.

The DCF approach is usually represented by the following formula:

$$k = {}^{d}/_{P} + g$$

where k = required rate of return
d = dividend in the immediate period
P = market price
g = expected growth rate in dividends

While the DCF method is usually presented in mathematical notation format (as above), it can also be described in narrative fashion. The formula says that the return that any investor expects from the purchase of a stock consists of two components. The first is the immediate cash flow in the form of a dividend. The second is the prospect for future growth in dividends. The sum of the rates of these two flows, present and future, equals the return that investors require. Investors adjust the price they are willing to pay for the stock until the sum of the dividend yield and the annual rate of expected future growth in dividends equals the rate of return they expect from other investments of comparable risk. The DCF test thus determines what the investing community requires from the company in terms of present and future dividends relative to the current market price.

Q. DON'T MOST INVESTORS REGARD CAPITAL APPRECIATION AS A PORTION OF THEIR EXPECTED RETURN?

A. Yes. The expectation of capital appreciation is captured in the "g" or growth portion of the DCF formula. If dividends grow, then it follows that the market price of the stock will grow as well. It is this growth that most equity investors seek, at least in part, in purchasing shares in a traded company.

Q. IS THERE A CONVENTIONAL PROCEDURE FOR CALCULATING DCF RETURNS?

A. Yes. There is a conventional procedure for calculating equity return under the DCF formula that is often referred to as the "classic" DCF calculation. The Federal Communications Commission ("FCC") has concluded that this method

should be given the greatest weight in determining the rate of return to equity.[2] I agree with this conclusion.

Q. HOW IS THE "g" OR GROWTH FACTOR IN THE DCF FORMULA IDENTIFIED UNDER THE CLASSIC DCF CALCULATION?

A According to the DCF theory, the relevant measure of "g" should be the growth in dividends. Dividends, however, are largely a function of management discretion, and they do not necessarily reflect the underlying driver of earnings. Simply by changing the dividend payout ratio, a company's management can create a rate of dividend growth that is unsustainable. For this reason, I believe that earnings per share ("EPS") is the most reliable indicator of the "g" factor.

The classic DCF calculation employs predictions of EPS growth, usually in the three to five year time horizon. Investment analysts routinely attempt to forecast future earnings of traded companies. No one forecast can be considered reliable, but presumably a consensus of forecasts might be a good indication of investors' collective expectations as regards the company's future prospects.

The two most commonly used sources of investment analysts' predictions are the Institutional Brokers Estimate System ("I/B/E/S") and a somewhat broader survey of investment analysts by Zacks Investment Research, Inc., which includes retail as well as institutional brokers.

Q. WHAT ARE THE CONSENSUS ESTIMATES OF EPS GROWTH FOR THE COMPARABLE COMPANIES THAT YOU HAVE IDENTIFIED?

A. The Zacks' five year consensus growth estimates are as follows:

[2] *Notice Initiating a Prescription Proceeding and Notice of Proposed Rulemaking,* CC Docket No. 98-166, October 5, 1998.

Table 3
Zacks Five Year Consensus EPS Forecasts

Atmos Energy Corp.	6.43%
AGL Resources	11.42%
Cascade Natural Gas Corp.	5.25%
LaClede Group, Inc.	4.25%
NICOR, Inc.	6.10%
Northwest Natural Gas Co.	6.06%
People's Energy Corp.	6.80%
Piedmont Natural Gas Co.	4.67%
South Jersey Industries, Inc.	6.00%
Southwest Gas	6.80%
WGL Holdings, Inc.	3.65%

Source: Zacks Investments Research, Inc., Company Reports.

Q. HOW DOES THE CLASSIC DCF CALCULATION DERIVE THE DIVIDEND YIELD PORTION OF THE DCF FORMULA?

A. Under the classic calculation, the dividend yield is calculated as the next year's dividend divided by an average of recent prices of the stock. The resultant yield should reasonably match the dividend yields shown by the financial reporting services.

There are several ways to predict next year's dividend. Several investors' services provide forecasts of dividends. Another, somewhat more mechanical approach is to compute the next year's dividend as the most recent dividend annualized and then increased by one half of the analysts' prediction of long-term annual growth rate in earnings per share.

Q. WHAT ARE THE NEXT YEAR'S DIVIDENDS FOR THE COMPARISON COMPANIES YOU HAVE IDENTIFIED?

A. Using the mechanical approach, I calculate the following dividends for the comparison companies.

Table 4
Next Period Dividends

Company	Dividend (1)	½ Growth	Next Year Dividend
Atmos Energy Corp.	$1.18	3.22%	$ 1.22
AGL Resources	$1.08	5.71%	$ 1.14
Cascade Natural Gas Corp.	$0.96	2.63%	$ 0.99
LaClede Group, Inc.	$1.34	2.13%	$ 1.37
NICOR, Inc.	$1.84	3.05%	$ 1.90
Northwest Natural Gas Co.	$1.26	3.03%	$ 1.30
People's Energy Corp.	$2.08	3.40%	$ 2.15
Piedmont Natural Gas Co.	$1.60	2.34%	$ 1.64
South Jersey Industries, Inc.	$1.50	3.00%	$ 1.55
Southwest Gas	$0.82	3.40%	$ 0.85
WGL Holdings, Inc.	$1.27	1.83%	$ 1.29

(1) Zacks Company Reports

Q. HOW IS THE DENOMINATOR IN THE DIVIDEND YIELD CALCULATION, THE RECENT PRICE OF THE STOCKS, IDENTIFIED?

A. Some judgement is required to establish a set of price observations that capture the investing public's current perception of value, while at the same time reflecting some stability in the market. Given the fluctuations of the markets, a price observation for a single day, week, or even month runs the risk of becoming obsolete in a very short time. Market fluctuations also mean that the use of monthly highs and lows may exaggerate the effect of some of the sharp drops and rises that the markets have experienced recently. For this reason, I believe it is best to use the average of prices over a period somewhat longer than a month. Since CBS MarketWatch routinely publishes the average of the 50 most recent trading day closing prices, I have chosen this series as the price basis for the calculation of dividend yield.

Q. WHAT IS THE DIVIDEND YIELD OF YOUR COMPARISON COMPANIES?

A. Using the foregoing dividends and the MarketWatch price averages, I calculate the dividend yields as follows:

Table 5

Next Period Dividend Yields

Company	Dividend	50-Day Avg. Price	Dividend Yield
Atmos Energy Corp.	$ 1.22	$ 21.63	5.63%
AGL Resources	$ 1.14	$ 21.76	5.25%
Cascade Natural Gas Corp.	$ 0.99	$ 19.69	5.00%
LaClede Group, Inc.	$ 1.37	$ 22.65	6.04%
NICOR, Inc.	$ 1.90	$ 35.06	5.41%
Northwest Natural Gas Co.	$ 1.30	$ 28.28	4.59%
People's Energy Corp.	$ 2.15	$ 34.00	6.33%
Piedmont Natural Gas Co.	$ 1.64	$ 34.45	4.75%
South Jersey Industries, Inc.	$ 1.55	$ 32.85	4.70%
Southwest Gas	$ 0.85	$ 22.79	3.72%
WGL Holdings, Inc.	$ 1.29	$ 24.21	5.34%

Note: 50 day prices prior to August 24, 2002. Source: CBS MarketWatch.

Q. WHAT ARE THE RESULTS FOR THE "CLASSIC" DCF FORMULATION?

A. The "classic" formulation of the DCF procedure is the sum the growth rates identified in Table 3 with the dividend yields in Table 5, as follows:

Table 6
"Classic" DCF Results

Company	Growth	Dividend Yield	DCF Return
Atmos Energy Corp.	6.43%	5.63%	12.06%
AGL Resources	11.42%	5.25%	16.67%
Cascade Natural Gas Corp.	5.25%	5.00%	10.25%
LaClede Group, Inc.	4.25%	6.04%	10.29%
NICOR, Inc.	6.10%	5.41%	11.51%
Northwest Natural Gas Co.	6.06%	4.59%	10.65%
People's Energy Corp.	6.80%	6.33%	13.13%
Piedmont Natural Gas Co.	4.67%	4.75%	9.42%
South Jersey Industries, Inc.	6.00%	4.70%	10.7%
Southwest Gas	6.80%	3.72%	10.52%
WGL Holdings, Inc.	3.65%	5.34%	8.99%
Average	6.13%	5.16%	**11.29%**

Q. ARE THERE ALTERNATIVE FORMULATIONS OF THE DCF PROCEDURE?

A. Yes. There are broadly two alternative formulations to the DCF procedure that have been used in utility rate of return studies, both reflecting different ways of estimating the "g" or growth factor. The first is based on the proposition that growth in earnings and dividends for a regulated public utility is constrained by the growth in book value per share. This is because public utility regulation has traditionally authorized earnings in relation to a "rate base" reflective of the book value of the investment devoted to utility service. The rate of growth in per-share book value is a function of (1) the earnings retention ratio, (2) the authorized rate of return and (3) dilution or accretion from sales of new stock.

The other alternative uses historical trends in growth in earnings and dividends to calculate the "g" factor in the DCF formula.

Q. WHAT IS YOUR ASSESSMENT OF THE BOOK VALUE GROWTH MODEL FOR THE COMPARABLE COMPANIES YOU HAVE IDENTIFIED?

A. The book value growth model is less useful for gas utilities than it used to be for two reasons. Although I have limited my selection of comparable utilities to those deriving over 75 percent of their revenues from gas distribution, only two of these companies generate all of their revenue from this source. The remaining eight still have some unregulated – or FERC regulated – activities for which the book value growth model does not apply as well.

Possibly more relevant is the fact that very few utilities are so closely regulated that the only source of growth in earnings is the increase in book value. Since the late 1980s, when the gas distribution utility industry generally began experiencing declining costs, there have been relatively few rate cases. MDU is a good example. MDU's last gas rate case, No. PU-399-96-325, resulted in a settlement agreement that reduced rates in December 1998. The last general gas rate increase was in November 1994 in Case No. PU-399-94-297. This suggests that MDU apparently has earned more than its authorized rate of return during the intervening years. If MDU has been able to enjoy returns above what regulation might have established as the authorized rate of return, then its "g" factor would be greater than would be indicated by the earnings growth model.

Q. RECOGNIZING THESE LIMITATIONS TO THE BOOK VALUE GROWTH MODEL, HAVE YOU DEVELOPED "g" FACTORS FOR YOUR COMPARISON COMPANIES REFLECTING THAT APPROACH?

A. Yes. Exhibit___(CWK-4) develops this approach using data forecast by Value Line for the period 2005-2007. I divide the predicted dividend by the forecast earnings and use the complement as the earnings retention ratio, that is, the proportion of earnings not distributed as dividends. I multiply this ratio by Value

Line's forecast return on book common equity to derive the growth in book value from retained earnings.

The second factor in the book value growth model is the opportunity to augment book value by selling stock at prices that exceed book value. For each company, I chart the annual percentage increase in shares of stock between 2002 and 2006 as predicted by Value Line. I then multiply the average percentage increase in shares by the percentage that recent market prices (last 50 days) have exceeded book value.

The results for this version of the DCF model are as follows:

Table 7
Book Value Growth DCF Results

Company	Earnings Retention Growth	Stock Sales Increment	Dividend Yield	DCF Return
Atmos Energy Corp.	5.73%	3.06%	5.63%	14.42%
AGL Resources	5.82%	0.46%	5.25%	11.53%
Cascade Natural Gas Corp.	7.91%	2.20%	5.00%	15.11%
LaClede Group, Inc.	4.27%	0.92%	6.04%	11.23%
NICOR, Inc.	10.55%	0.00%	5.41%	15.96%
Northwest Natural Gas Co.	5.53%	0.00%	4.59%	10.12%
People's Energy Corp.	5.75%	0.00%	6.33%	12.07%
Piedmont Natural Gas Co.	4.52%	1.97%	4.75%	11.24%
South Jersey Industries, Inc.	5.44%	2.42%	4.70%	12.57%
Southwest Gas	4.80%	0.00%	3.72%	8.52%
WGL Holdings, Inc.	5.87%	0.00%	5.34%	11.21%
Average	6.02%	1.00%	5.16%	**12.18%**

Q. HOW DO YOU INTERPRET THE RESULTS OF THIS APPROACH?

A. This application of the book value growth model is entirely dependent on Value Line's forecasts of growth between now and the period 2005-2007. Value Line, like most Wall Street analysts, tends to be quite optimistic regarding business prospects. For example, there are no examples of level or declining earnings,

even though the historical record of these companies show a number of years in which earnings have declined. There are no examples where the return to book equity is assumed to be any lower than recent years, even where the earnings (e.g. NICOR at 21.5%) are clearly above those that regulators would likely allow in formal rate cases. For these reasons, I believe that the results of the earnings growth model must be considered the upper bound of the likely return requirements of my comparison companies.

Another factor suggesting a possible up-side bias is the probability that the companies will not realize the increments in share value resulting from the sale of shares above book value. In many cases, the new shares are not sold, or if they are sold, not at market value. For example, when officers exercise stock options for which they pay prices much lower than market, the effect can be to dilute the book value of the shares, not increase them. In this analysis, however, I have assumed that every new share results in an increment in equity equivalent to the market price.

Q. WHAT IS THE RELEVANCE OF HISTORICAL GROWTH MODEL TO THE ESTIMATION OF EARNINGS REQUIREMENTS?

A. Historical trends in dividends and earnings are relevant to an estimation of the "g" factor only to the extent that investors regard them as indicators of their future expectations. Most financial reports display considerable historical data, including past earnings per share and dividends, which suggests that this information is of interest to investors and analysts. The weight that they give to the trends in these indicators is, of course, unknown and unknowable.

Q. WHAT IS THE RESULT OF THE DCF MODEL IF HISTORICAL TRENDS IN EARNINGS PER SHARE ARE USED TO ESTIMATE THE "g" FACTOR?

A. Using the record of average growth in diluted earnings per share before non-recurring items from Zacks Research Reports beginning in 1997 and running through Value Line's forecast for 2002, the DCF model yields the following estimates of earnings requirements.

Table 8

Historical 1997-2002 EPS Growth DCF Results

	EPS Growth	Dividend Yield	DCF Return
Atmos Energy Corp.	12.04%	5.63%	17.67%
AGL Resources	6.94%	5.25%	12.18%
Cascade Natural Gas Corp.	10.21%	5.00%	15.21%
LaClede Group, Inc.	-7.15%	6.04%	-1.11%
NICOR, Inc.	4.55%	5.41%	9.96%
Northwest Natural Gas Co.	5.34%	4.59%	9.93%
People's Energy Corp.	0.69%	6.33%	7.01%
Piedmont Natural Gas Co.	1.21%	4.75%	5.97%
South Jersey Industries, Inc.	10.47%	4.70%	15.17%
Southwest Gas	33.84%	3.72%	37.56%
WGL Holdings, Inc.	-6.02%	5.34%	-0.68%
Mean	6.56%	5.16%	**11.72%**
Median			**10.84%**

Q. WHAT IS YOUR ASSESSMENT OF THE USE OF HISTORICAL EARNINGS GROWTH AS AN INDICATOR OF THE "g" FACTOR IN THE DCF FORMULA?

A. I doubt that investors take seriously earnings trends that are at either the high or the low end of the earnings growth spectrum. For example, it is unlikely that anyone expects Southwest Gas to continue to experience earnings growth of 37.56 percent annually, particularly as that number is an average of annual changes that range from an increase 170 percent to a decrease of 16 percent. At the other extreme, investors clearly do not expect LaClede's earnings to continue to decline. If they did, the stock would not be experiencing a dividend yield of only

6.04 percent. Possibly there is credence to the evidence of earnings trends that reflect a consistent pattern of growth from year to year. For this reason , I would give more weight to the median growth weight than to the mean, particularly as the mean rate of growth is affected by the high number for Southwest Gas and the low numbers for LaClede and WGL.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR DCF ANALYSES.

A I have applied the "classic" DCF procedure and two modifications based on alternative ways of calculating the "g" or growth factor. The results can be summarized as follows:

Table.9
Discounted Cash Flow Analysis Results

	Classic	Book Value Growth	Historical Growth
Atmos Energy Corp.	12.06%	14.42%	17.67%
AGL Resources	16.67%	11.53%	12.18%
Cascade Natural Gas Corp.	10.25%	15.11%	15.21%
LaClede Group, Inc.	10.29%	11.23%	-1.11%
NICOR, Inc.	11.51%	15.96%	9.96%
Northwest Natural Gas Co.	10.65%	10.12%	9.93%
People's Energy Corp.	13.13%	12.07%	7.01%
Piedmont Natural Gas Co.	9.42%	11.24%	5.97%
South Jersey Industries, Inc.	10.7%	12.57%	15.17%
Southwest Gas	10.52%	8.52%	37.56%
WGL Holdings, Inc.	8.99%	11.21%	-0.68%
Average	**11.29%**	**12.18%**	**11.72%**

Q. HOW DO YOU INTERPRET THESE RESULTS?

A. As noted earlier, the "classic" form of the DCF model should be given the most weight. However, when those results are widely different from the book value growth model, there is reason to question the sustainability of the earnings

forecasts derived from Zacks survey of investment analysts. For example, Zacks' survey shows that analysts are predicting earnings growth of 11.4 percent annually for AGL. However, the pattern of earnings retention by this company indicates that it would support book value growth of only 5.9 percent. In this case, it is reasonable to assume that the classic DCF model is overestimating the earnings expectation of serious investors in this company. The reverse is true of WGL Holdings, where Zacks reports that analysts are forecasting earnings growth of only 3.65 percent, yet the rate of earnings retention will generate a growth in book value, hence earnings capability, of 5.9 percent. In other cases, e.g. LaClede, Northwest, the classic and book value growth models are within 100 basis points of each other.

Q. CAN YOU PROVIDE AN ESTIMATE OF THE DCF RETURNS FOR EACH OF YOUR COMPARISON COMPANIES?

A. While precision is impossible, I can estimate the DCF returns of each company by using the classic result as the baseline and adjusting upward or downward where there are marked differences between that result and the book value growth, and to a lesser extent, the historical growth models. Here is my best set of estimates:

Table 10
Discounted Cash Flow Results

Company	Return
Atmos Energy Corp.	12.5%
AGL Resources	14.0%
Cascade Natural Gas Corp.	11.0%
LaClede Group, Inc.	10.5%
NICOR, Inc.	12.0%
Northwest Natural Gas Co.	10.5%
People's Energy Corp.	12.5%
Piedmont Natural Gas Co.	10.0%
South Jersey Industries, Inc.	11.0%
Southwest Gas	10.0%
WGL Holdings, Inc.	9.5%
Average	**11.23%**

Q. CAN YOU EXPLAIN THE VARIATIONS AMONG THESE RETURNS?

A. Considerable light can be shed on the differences among these companies' returns by looking at two sets of data, the proportion of revenue derived from regulated gas distribution service and the proportion of common equity in the company's capital structure:

Table 11
Proportions of Gas Distribution Revenue and Equity in Capital Structure

Company	% Gas Distribution	% Equity
Atmos Energy Corp.	95.6%	39.0%
AGL Resources	87.1%	35.1%
Cascade Natural Gas Corp.	100.0%	42.4%
LaClede Group, Inc.	92.8%	41.7%
NICOR, Inc.	83.4%	49.9%
Northwest Natural Gas Co.	97.8%	45.5%
People's Energy Corp.	80.8%	39.2%
Piedmont Natural Gas Co.	100.0%	50.8%
South Jersey Industries, Inc.	100.0%	32.5%
Southwest Gas	85.4%	31.9%
WGL Holdings, Inc.	74.6%	49.8%
MDU Utilities' Gas Distribution	**100.0%**	**44.55%**

The very high return requirements of Atmos, AGL and People's Energy can be explained by their relatively low equity proportions. The less equity in the capital structure, the greater the financial risk from variations in operating income. In the case of People's Energy, there is the added risk that the proportion of gas distribution revenue is relatively low in comparison to the other members of the comparison group. The relatively low proportion of gas distribution revenue may also explain the high return for NICOR, in spite of its high equity ratio and consequent low financial risk.

The companies showing very low return requirements can also be explained. Piedmont is a clear example of a low-risk company, with 100 percent of its revenue derived from gas distribution service and an equity proportion of over 50 percent. WGL also has a low-risk capital structure. Its 75 percent gas distribution revenue percentage might suggest higher risk except that most of the non-regulated revenue is derived from Washington Gas Energy Services, a supplier of gas to the very same customers who receive gas distributed by its regulated subsidiary.

Southwest Gas appears to be an anomaly, with a very low return requirement in spite of having less than 86 percent of its revenue from gas distribution and common equity proportions of only about 32 percent. These figures are somewhat deceiving, however. Southwest Gas has a low earnings growth forecast, but it serves very fast-growing population centers in Arizona, Nevada and California. Possibly, this assurance of long-term growth reduces the perceived risk of this company.

Q. HOW DOES MDU FIT INTO THIS PICTURE?

A. Table 11 shows that MDU's gas distribution operation service, with 100 percent gas distribution revenue and an equity proportion of 44.6 percent, is at the low end of the risk spectrum. Its profile most closely corresponds to that of Piedmont Natural Gas, with a return requirement of only 10.0 percent.

Q. WHAT RATE OF RETURN DO YOU RECOMMEND FOR MDU'S GAS OPERATIONS?

A. In light of low level of MDU's business and financial risk, I believe a good case could be made for setting its rate of return to equity at the very bottom of the scale shown on Table 10, 9.5 to 10 percent. However, the rate of return set in this

proceeding is likely to remain in effect for a number of years. I therefore believe it unadvisable to lock the company into a relatively low return for an extended period during which business conditions, capital costs and the company's outlook might change. For this reason, I recommend a return at the mid-point between the average for the 11 comparison companies, 11.23 percent, and the return requirement for three lowest-risk companies, 9.5 to 10.0 percent. That mid-point between 11.23 percent and 9.75 percent is **10.5 percent.**

Q. YOUR RECOMMENDATION IS BETWEEN 220 AND 330 BASIS POINTS LOWER THAN THE DCF RETURN FOUND BY DR. GASKE. WHAT ACCOUNTS FOR THE DIFFERENCE?

A. Dr. Gaske has used a much smaller sample of proxy companies than I have, six versus 11. Five of his companies are included in my comparison group, but the sixth, Keyspan, does not belong in any comparison with MDU's gas operations. Keyspan derives only 50 percent of its revenue from gas distribution operations and undoubtedly has a higher level of risk as a consequence.

A major difference between Dr. Gaske's results and mine relates to the LaClede Group. Dr. Gaske reports that Zacks has forecast a 12 percent 5-year earnings growth rate for this company. I do not find this result. I have attached Zacks report on LaClede as of August 24, 2002 as Exhibit____(CWK-5). Page 3 of that report indicates that the analysts' forecast as of that date was that LaClede's 5-year growth will be 4.25 percent.

There are two other identifiable differences between my DCF application and that of Dr. Gaske. First, Dr. Gaske inflates his results by 4.75 percent to account for flotation costs associated with new issues of stock. Second, Dr. Gaske uses a 1.625 percent inflator to the current dividend to calculate next year's dividend.

Q. IS DR. GASKE'S ADDER FOR FLOTATION COSTS APPROPRIATE?

A. No. Flotation costs are incurred only when a company issues new stock, and then only when there is a public stock offering. Existing stock incurs no flotation cost, and even new stock incurs no such costs if it is distributed as an employee or shareholder benefit either through options or as bonuses.

The effect of Dr. Gaske's flotation cost adjustment is to increase his equity return by 60 basis points, or .60 percentage points. When multiplied by the $1.125 million book equity value of the MDU Resources, Inc., this allowance amounts to $6.75 million annually, which is substantially more than the $5.4 million in flotation costs that the Company has incurred over the past five years.[3]

If a flotation cost adder is to be used, it should be equal to a reasonable estimate of the annual flotation cost incurrence divided by the entire amount of the Company's equity. In MDU's case, annual flotation costs during the past five years have been about $1.1 million. The Company's total book equity value is $1,125 million, for a flotation cost allowance of 0.1 percent. This amount is so small as to be lost in the rounding. For this reason, I recommend that there be no explicit flotation cost adder.

In Case No. PU-399-01-186 involving MDU's electric rates, the Commission agreed with this position.[4]

Q. IS DR. GASKE'S INFLATOR OF 1.625 FOR THE CURRENT DIVIDEND APPROPRIATE?

A. No. Dr. Gaske's factor is incorrect because it assumes that the investor will not receive his/her first dividend until exactly three months from the date of purchase. The average for the next dividend increase is thus (.25+.50+.75+1.0)/4 = .625.

[3] Case No. PU-399-01-186, MDU Response to King January 22 Data Request No. 6.
[4] See Order dated April 24, 2002, ¶ 15.

My .5g factor assumes that the probability of the dividend increase is randomly distributed throughout the year following the purchase of the stock. The average delay in the dividend increase under this assumption is one-half a year, so that the appropriate factor is .5g.

The effect of this disagreement on the final result, however, is minimal.

2. INTEREST RATE RISK PREMIUM APPROACH

Q. WHAT IS THE INTEREST RATE RISK PREMIUM APPROACH?

A. While equity return requirements are difficult to estimate, bond yields and interest rates can be measured with precision and currency. Indeed, they are reported daily in business publications and weekly by the Federal Reserve Board. The interest rate risk premium approach attempts to analyze the relationship between measurable interest rates and bond yields and immeasurable equity returns.

The reason for this relationship is that fixed income investments – bonds and preferred stock – compete with common stock for investors' dollars. If interest rates fall, then (all other things being equal) investors have an increased incentive to commit their funds to the stock market. As more funds flow into stocks, their prices increase, reducing the return available from current and forecast profits. Conversely, if interest rates increase, then stock prices fall, and the return to the newly repriced equity market increases.

To be sure, the return requirements of the two forms of investment do not move in lock step. Bonds suffer inflation risk, while stocks are considered a hedge against inflation. Conversely, stocks are far more susceptible to the effects of the business cycle than bonds, so when recession threatens, the spread between bond yields and required stock returns is likely to increase. Nonetheless, over time, a

decline in bond yields should signal a corresponding (although not directly correlated) decline in equity return requirements.

Q. WHAT IS THE VALUE OF THE INTEREST RATE RISK PREMIUM APPROACH?

A. It is worthwhile to examine the trend in bond yields and interest rates over the time since earlier equity return prescriptions were made for gas utilities in North Dakota to determine whether a finding of 10.5 percent is reasonable. If it appears that bond yields have increased, but I am recommending a reduced return to equity, then there may be reason to question my finding. On the other hand, if my proposed equity return tracks with the changes in bond yields, then there is at least a "sanity check" on the propriety of my finding.

Q. WHAT IS THE RELATIONSHIP BETWEEN EQUITY RETURN ALLOWANCES AND BOND YIELDS OVER THE YEARS?

Exhibit_____(CWK-6) provides this comparison. It shows the average monthly yields to 10-year Treasury and Moody's Aaa Corporate bonds from 1990 through to the latest month 2000 and to July 2002. It also shows the three gas equity return findings by North Dakota Commission since 1990. The chart shows that bond yields have been declining generally and are now at almost their lowest level in 12 years, significantly below their position when the previous return findings were made.

The specific relationship between the equity return findings and the then-current bond yields is as follows:

Table 12
Gas Equity Return Allowances and Contemporaneous Bond Yields

Case	Utility	Date	ROE Allowed	10-Yr Treas.	Aaa Corporate
399-90-820	MDU	July 30, 1991	12.0%	8.27%	9.00%
400-95-559	NSP	June 7, 1996	12.0%	6.91%	7.71%
400-00-521	NSP	June 27, 2001	11.5%	5.28%	7.18%
399-02-183	**MDU**	August , 2002	**10.5%***	4.35%	6.45%

*Staff proposed
Source: PSC Records and Federal Reserve Statistical Releases.

Q. WHAT DO YOU CONCLUDE FROM THESE COMPARISONS?

A. I conclude that while my recommended equity return allowance is lower than any that have been approved for gas utilities in the past 12 years, this result is justified by the evidence of lower overall capital costs. Those lower capital costs are demonstrated by a dramatic reduction in bond yields relative to the experience of the past 12 years. For this reason, I conclude that my recommended equity return of 10.3 percent is reasonable.

Q. WOULD YOU PLEASE COMMENT ON DR. GASKE'S RISK PREMIUM ANALYSIS.

A. In pages 22-24 of his testimony, Dr. Gaske purports to measure the required return to equity by adding the historical difference in experienced earnings from stocks and bonds to the current levels of bond yields. These historical differences, as measured by Ibbotson Associates, go back to 1926.

I have encountered this historical risk premium approach in a number of rate-of-return proceedings and have always found it so flawed, both conceptually and statistically, as to be virtually worthless.

The historical risk premium approach calculates the experienced returns to common stocks, bonds and Treasury bills on a monthly basis since 1926. It then

assumes that the experienced differences in return between stocks and bonds represent the expected differences in return. The theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials.

This is a statement of faith, not experience, and it defies logic. If investors' short-term expectations are continually being frustrated (as has been the case during the last year), what possible logic supports the proposition that the sum of those failed short-term expectations represents a valid long-term representation of their expectations? Moreover, it is flatly untrue that the differential in required returns between bonds and stocks is fixed and unchanging, as this theory postulates. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.

Quite apart from this conceptual failing, the theory fails statistically. The standard deviations of the observations, particularly the observations of the return differences, are greater than the mean of those observations. The means therefore lack statistical significance and are useless as a predictive tool.

Q. WOULD YOU PLEASE COMMENT ON DR. GASKE'S ALTERNATIVE EQUITY INVESTMENT ANALYSIS?

A. In pages 24-26 of his testimony, Dr. Gaske purports to demonstrate that MDU should be allowed a high return by observing that the returns to book equity on the S&P 500 companies from 1977 to 2000 have averaged 21.47 percent. He also observes that the book equity returns to 746 industrial, retail and transportation companies included in *The Value Line Investment Survey* have ranged from 27.57 percent to 31.75 percent over the five years 1996-2000. He argues that the average of 29.4 percent, along with the return of 21.47 percent experienced by

S&P's 500 companies, represents a "benchmark" which suggests that the 13.25 percent he proposes for MDU is quite low.

These comparisons are utterly irrelevant. Investors in unregulated industrial, retail and transportation firms have no access to book equity value. The only value that is meaningful for investors in such firms is the market value. That is what an investor must pay to acquire the stock, and conversely, the value an investor will receive by selling the stock. Book equity value in an industrial firm is a purely historical number representing the dollars of original investment in equity capital contributed to (or retained by) the company. It has little relevance to the current market value, even for fairly capital-intensive firms. Since most stocks sell well above their book value, the return that is accessible to investor is considerably less than the 20 to 30 percent noted by Dr. Gaske.

Book values are relevant for regulated utilities because regulation makes them so. Regulation sets the earnings allowance for such companies relative to a rate base reflective of the book value of the capital invested utility operations. This condition does not apply to industrial firms.

Q. IS THERE ANY JUSTIFICATION FOR DR. GASKE'S CLAIM THAT MDU IS ENTITLED TO A RISK PREMIUM BY REASON OF ITS SMALL SIZE?

A. No. While MDU's gas operations are relatively small, those operations do not sell stock. The parent company, MDU Resources Group, Inc is the entity that sells stock on behalf of MDU's gas operations. As Schedule 2 to Dr. Gaske's Exhibit (JSG-2) shows, MDU Resources is well within the size range of Dr. Gaske's own group of proxy gas companies. There is no small company effect whatever associated with MDU's equity capital cost.

D. RETURN TO TOTAL CAPITAL

Q. WHAT IS YOUR RECOMMENDED RETURN TO MDU's TOTAL CAPITAL?

A. My recommended return to total capital is **7.98 percent**, calculated as follows:

Table 13
Return to Total Capital

Item	Proportion	Cost	Weighted Cost
Long-term Debt	47.92%	6.167%	2.96%
Short Term Debt	2.78%	4.542%	0.13%
Preferred Stock	4.75%	4.630%	0.22%
Equity	44.55%	10.50%	4.68%
Total	100.00%		**7.98%**

PART II - CLASS COST OF SERVICE STUDY

Q. WHAT IS A CLASS COST OF SERVICE STUDY?

A. A class cost of service study is an analysis of the embedded or incremental costs of providing utility services to the customers or classes of customers that either cause these costs, or to whom these costs can reasonably be allocated.

Q. WHAT IS THE PURPOSE OF A CLASS COST OF SERVICE STUDY?

A The purpose of a class cost of service study is to provide an indication of what it costs to provide utility service to each customer class. This information can be used as a guideline for determining what portion of the revenue requirement should be recovered from each customer class.

Q. HOW HAS THE COMMISSION USED THESE STUDIES IN THE PAST?

A. In prior rate applications the Commission has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers.

Q. WHAT TYPE OF CLASS COST OF SERVICE STUDY HAS MDU SUBMITTED IN THIS CASE?

A. MDU Witness Tamie Aberle has sponsored Statement M, which is an embedded cost of service study for the year ended December 31, 2001. An embedded cost of service study allocates the recorded costs of an historical year among the respective customer classes. The sum of the embedded costs reconcile generally with the revenue requirement for the same historical year. Embedded cost of service studies contrast with incremental cost studies that measure the going-

forward costs that each customer class will generate in the coming years. Incremental costs do not necessarily reconcile with the revenue requirement.

Q. PLEASE DESCRIBE BRIEFLY THE MECHANICS OF A CLASS COST OF SERVICE STUDY.

A. The first step in performing a cost of service study is to funtionalize costs according to the major functions they serve, such as gas acquisition, transportation, storage and distribution. In this particular case, the focus is almost entirely on the last of these functions, distribution, because the other functions represent costs that are calculated and recovered through the Purchased Gas Cost Adjustment.

The next step is to classify the functionalized distribution costs into three broad categories for allocation purposes:

- Capacity related costs vary with the amount of gas sendout on the peak days of the year. Examples include the sizing of distribution mains and meters to account for the maximum volume of gas handled on any one day;
- Throughput related costs vary with the total amount of gas distributed throughout the year. Uncollectible accounts is a good example of this type of cost;
- Customer related costs vary with the number of customers. Examples include the cost of meters, services and billing.

After the costs have been classified they are allocated or assigned to each customer class. These allocations and assignments are then summed by class to provide an indication of the costs of service to each customer class.

Q. ARE THERE DEFINITE RULES FOR CLASSIFYING AND ALLOCATING COSTS WHEN PERFORMING A CLASS COST OF SERVICE STUDY?

A. No. Many costs do not fall into obvious classifications, and there can be more than one method for each allocation. Implementation is influenced by the judgments of the particular analyst. This is particularly true of gas distribution costs, as I shall discuss. The National Association of Regulatory Utility Commissioners ("NARUC") has published a Gas Distribution Rate Design Manual that describes cost classification and commonly used allocation methods. It does not, however, endorse any single specific method.

Q. HOW ARE CAPACITY COSTS ALLOCATED IN THE MDU COST OF SERVICE STUDY?

A. Capacity costs are allocated according to the class distribution of sales or throughput during the peak two days of the year.

Q. HOW ARE CUSTOMER COSTS ALLOCATED IN THE MDU COST OF SERVICE STUDY?

A. Most customer costs are allocated based on the count of customers in each class. Some costs, such as meters, are weighted according to the cost of the meters required for customers consuming different quantities of gas.

Q. WHAT ARE THE LARGEST CATEGORIES OF DISTRIBUTION PLANT?

A Three categories of plant account for almost 75 percent of MDU's gas distribution plant, as follows:

Table 14
MDU Gas Distribution Plant
December 31, 2001

Mains	$ 27,079,883	39.1%
Services	12,124,678	17.5%
Meters	11,963,141	17.3%
Other Distribution	4,391,190	6.3%
General & Common	13,763,316	19.9%
Total	$ 69,322,208	100.0%

Q. HOW HAS MDU ALLOCATED THESE THREE PRINCIPAL CATEGORIES OF PLANT AMONG THE CLASSES?

A. MDU has allocated services and meters by the number of customers weighted for their different consumption levels. MDU allocates 64 percent of its mains costs on the basis of peak 2 day throughput and 36 percent on the basis of the number of customers.

Q. DO YOU AGREE WITH THIS ALLOCATION?

A. I accept the allocation of services and meters based on weighted customers, but I question the propriety of allocating mains partially on the basis of customers.

Q. WHY DO YOU QUESTION THE ALLOCATION OF MAINS BASED ON THE NUMBER OF CUSTOMERS?

The issue is whether the mains system has been built to serve customers or to deliver gas. Arguably, the purpose is both, but the value derived and the benefits received from the mains system are more related to the amount of gas delivered than the number of customers. One customer receiving twice as much gas as another customer enjoys exactly twice the BTU heating content. The two cannot be equated in terms of benefit received, yet that is what a customer allocation of mains does.

Proponents of the customer allocation argue that the purpose of the mains system is to reach customers, and that when more customers are added, the mains system has to be extended. That is true only at the very edges of the system, where gas mains are being extended to serve new developments in previously unserved areas. Even then, the added cost of mains for new customers can vary dramatically depending on the location of those customers.

The vast majority of customers are served through the existing, embedded system of gas mains. For them, the customer allocation is irrational. Consider a 1,000-foot section of main line. Suppose that in 1995, that line served a single factory. In that year, its cost would be allocated to the commercial class on the basis of a single customer – a very small allocation. Then, in 1996, the factory moves, and the property is turned into a residential development of 10 homes. The same main is then given a weighting ten times as great as its previous allocation and assigned to the residential class. Then, in 2001, a strip mall containing 10 stores replaces five of the homes. The customer weighting of the main then increases to 15, split one third to the residential and two thirds to the commercial class. Yet it has been the same main all along, and its costs have remained the same.

Assume that the main delivered the same amount of gas throughout these changes in configuration. The benefit in terms of heating content was the same for the single factory as it was for the 10 homes. The 10 homes derived the same heating value as did the five homes and 10 stores. The heating content was the value delivered, and it should be the allocator of the main's cost.

Q. WHAT ALLOCATION OF MAINS COSTS DO YOU RECOMMEND?

A. I recommend an allocation that recognizes that the purpose of the mains system is to deliver gas, not to reach a count of customers. I therefore propose that the cost of mains be allocated one half to peak 2-day throughput and one-half to total

annual sales. I have requested the Company to rerun its cost of service study based on this alternative allocation of mains costs. Exhibit____(CWK-7) presents the summary pages of this alternative cost of service study.

Q. WHAT IS THE EFFECT OF THIS ALTERNATIVE ALLOCATION OF MAINS COSTS?

A. A comparison of the class rates of return under these two allocations of mains is as follows:

Table 15
Customer Class Rates of Return
Year Ended December 31, 2001

	Customer Allocation of Mains	No Customer Allocation
Residential	3.083%	7.731%
Firm General	3.998%	2.161%
Air Force	50.281%	3.502%
Small Interruptible Sales	83.992%	38.040%
Small Interruptible Transport	169.437%	48.490%
Large Interruptible	78.644%	-0.673%
Total North Dakota	6.439%	6.442%

The customer assignment of mains costs has a very significant effect on the cost allocation. It results in excessive costs being allocated to the residential class and away from the interruptible classes. Indeed, when mains costs are reallocated as I recommend, the Large Interruptible class goes from a very high rate of return to a negative return. The Air Force return drops dramatically, while the residential class return rises above the average for the system. The only consistent finding under the two allocation procedures is that the firm general class under-recovers costs, while the two small interruptible classes over-recover.

Q. HAS THE COMMISSION PREVIOUSLY REJECTED THE CUSTOMER ALLOCATION OF MAINS COSTS?

A. Yes. In MDU's 1991 rate case and in Northern States Power's 1996 case, the Commission rejected the allocation of mains costs partially on the basis of customer counts. In each of those cases, the Commission adopted the alternative of allocating all mains costs on the basis of peak day usage.[5] I believe that allocation overstates peak demand costs by failing to acknowledge that a portion of the mains system is required to deliver even a minimum amount of gas throughout the system. That is why I recommend that half the costs be allocated on the basis of annual sales.

PART III – RATE DESIGN

Q. HOW DOES THE COMPANY'S COST OF SERVICE STUDY AFFECT RATE DESIGN?

A. In the past, the Commission has used the cost of service study as a guide to determining differentials in the rate increases or decreases among classes. The Commission has also used these studies to set ceilings on specific charges, most notably the customer charge.[6]

Q. WHAT RATE DESIGN PROPOSALS HAS THE COMPANY MADE IN THIS CASE?

A. The Company has made a number of rate design proposals, as follows:

- Increase residential and firm general service rates by 4.6 percent, reduce the small interruptible class rates by 4.1 percent, and leave the Air Force and large interruptible rates unchanged;

[5] Case No. PU-399-90-820, decided July 30, 1991, ¶ 58; Case No. PU 400-95-559, decided August 7, 1996, ¶ 42.
[6] See Case No. PU-399-90-820, decided July 30, 1991; Case No. PU 400-95-559, decided August 7, 1996; Case No. PU-400-00-521, decided June 27, 2001.

- Separate the commodity rate into a Distribution Delivery Charge and a Cost of Gas charge, eliminating the Purchased Gas Cost Adjustment;
- Eliminate the declining block rate form from the commodity charges and substitute a flat per-dekatherm ("dk") rate;
- Change the customer, or "Basic Service Charge" from a monthly to a daily charge;
- Increase the Basic Service Charges by very large percentages. For example, the residential charge increases from $6.50 to $11.70, the small firm service charge from $8.50 to $24.00 and the large firm service charge from $17.00 to $51.00.
- Eliminate the residential seasonal rate;
- Increase the penalty for failure of interruptible customers to interrupt from $10 to $50 per dk;
- Increase the return check fee to $20;
- Increase the reconnection fees for seasonal customers to match the avoided Basic Service Charges;
- Increase the reconnection charge for disconnected customers for nonpayment to $30;
- Modify the Firm Gas Extension Policy Rate 120 and 124 to reflect the Company ownership of all prospective service lines.

Q HOW WILL YOU ADDRESS THESE RATE DESIGN PROPOSALS?

A. I will first address rate design changes that should be made in the absence of any overall revenue change whatever. These are changes that should be adopted whether the Commission increases, decreases or maintains the existing level of rates. I will then address rate changes that should be made if the Commission increases, or alternatively decreases current rates.

Q. WHAT RATE DESIGN CHANGES SHOULD BE MADE REGARDLESS OF THE CHANGE IN TOTAL REVENUE APPROVED BY THE COMMISSION?

A. I recommend that the Commission accept the following rate design changes proposed by MDU:

- The commodity rate should be separated into two clearly distinct rates, the Distribution Delivery Charge and the Cost of Gas Rate.
- The declining block rates should be eliminated and the revenue collected through the higher initial block rates should be reallocated to the Basic Service Charge.
- The residential seasonal rates should be eliminated, since there are no customers on these rates.
- Penalties for failure to interrupt should be increased, since the Company apparently believes that the current penalties are not sufficient to ensure that interruptible customers respond to their calls for interruption or curtailment.
- The reconnection charges for seasonal customers should be adjusted to match the higher Basic Service Charges resulting from the elimination of declining commodity blocks.
- The Company's proposed modifications to the line extension policy should be adopted.

Q. WHY DO YOU RECOMMEND ADOPTION OF THE DISTRIBUTION DELIVERY CHARGE AND THE COST OF GAS RATE?

A. This change makes the customer's bill more understandable. Customers will be able to distinguish between the portion of their bills that accrues to MDU for providing delivery service and the portion that is a pass-through of the gas acquisition, transportation and storage costs that accrue to other parties.

Q. WHY DO YOU SUPPORT THE ELIMINATION OF DECLINING BLOCK RATES?

A. Declining block rates implicitly encourage customers to use more gas and thereby discourage conservation. To the extent that they collect fixed customer costs in the commodity rate, they misstate the cause of the costs. They also allow customers who use minor amounts of gas for non-heating purposes to escape the cost of providing the basic elements of service to them.

Q. HAVE YOU CALCULATED THE INCREASED CUSTOMER CHARGES THAT WOULD RESULT FROM ELIMINATING DECLINING BLOCK RATES?

A. Yes. Exhibit_____(CWK-8) presents the calculation of the customer charges that result if declining blocks are eliminated from the residential and firm general service rate schedules. The exhibit identifies the excess revenues recovered by the higher initial blocks. It then divides those revenues by the total customer charges to compute the increase in each customer charge that would yield the same revenue. This calculation is based on historical 2001 billing determinants adjusted for normal weather conditions.

Exhibit_____(CWK-8) shows that the elimination of declining block rates would increase the small residential Basic Service Charge from $6.50 to $8.43 and the large residential charge from $13.00 to $15.31. The small Firm Service customer charge would increase from $8.50 to $14.34, while the large Firm Service customer charge would go from $17.00 to $45.16.

These Firm General Service rate increases seem quite large, but their impact on the average customer should be negligible because the commodity rates for the initial blocks will be substantially lower.

Q. HAVE YOU DETERMINED WHETHER THESE CUSTOMER CHARGES ARE EXCESSIVE FROM A COST STANDPOINT?

A. Yes. Exhibit _____(CWK-7) shows that the average customer cost for the residential class is $10.70 and the for the Firm General Service class it is $35.91. The final column in Exhibit_____(CWK-8) shows the weighted average customer charges of each of these classes. The residential weighted average customer charge is $8.44 and the Firm General customer charge averages $22.84, both well below the average unit customer costs for these classes.

Q. ARE THERE ANY OTHER PROPOSALS THAT THE COMPANY HAS MADE THAT YOU BELIEVE THE COMMISSION SHOULD CONSIDER REGARDLESS OF THE CHANGE IN OVERALL REVENUES?

A. I recommend that the Commission consider the Company's proposal to convert the Basic Service Customer Charge from a monthly charge to a daily charge. I agree with the Company that this proposal simplifies the calculation of the Basic Service Charge when customer take service during partial months, and it permits the Company to use billing intervals other than a month. My only concern is whether it might be accepted by the average customers as a reasonable way of charging for service. Unless there are strong customer objections to this proposal, I recommend it be adopted.

Q. ARE THERE ANY COMPANY PROPOSALS YOU RECOMMEND BE REJECTED REGARDLESS OF THE CHANGE IN REVENUE?

A. Yes. I recommend that the Commission reject the Company's proposal to increase the reconnection charge for discontinued service to $30. The Company claims that this is a cost-based rate, but I believe there is a legitimate public policy reason for not increasing this rate. The customers to whom this charge applies are almost certainly the lowest income customers. Otherwise, they would not have been disconnected. Since they have to pay their arrearages anyway, they are likely suffering some difficulty getting reconnected. To impose on them yet more

cost, such as an increase in the reconnection fee, might prevent some of these customers from obtaining vital utility service.

Q. HOW DOES MDU RECOMMEND THAT A RATE INCREASE BE DISTRIBUTED AMONG CUSTOMER CLASSES?

A. MDU proposes that the rate increase be imposed on the residential and general service classes and that a rate decrease be allowed to the Small Interruptible Class. The Air Force and the Large Interruptible Classes would experience no rate change. These proposals are based on the results of the Company's cost of service study, which shows the Air Force and the Interruptible classes earning significantly higher rates of return than the firm service classes.

Q. IS THIS PROPOSAL CONSISTENT WITH PAST COMMISSION PRECEDENT?

A. No. In previous cases the Commission has recognized different rates of return among classes by permitting lower rate increases to those classes showing the highest rates of return. It has not allowed rate reductions to some classes when most customers are suffering rate increases. For example, in the NSP rate case last year, the Commission allowed an increase to the interruptible class one-half the overall increase.[7] The same treatment was adopted in MDU's 1991 gas rate increase case, when the Company sought to withhold any increase to the Air Force and interruptible classes.[8]

Q. DO YOU RECOMMEND THAT THIS TRADITOINAL TREATMENT BE APPLIED IF THERE IS A RATE INCREASE IN THIS CASE?

[7] Case No. PU-400-00-521, decided June 27, 2001, ¶ 22
[8] Case No. PU-399-90-820, decided July 30, 1991, ¶ 61

A. Yes, I do. The two cost studies in the record disagree as to the rates of return earned by the Air Force and Large Interruptible rate schedules, but they agree that the Small Interruptible class generates a much higher than average rate of return. For this reason, and consistent with Commission precedent, I recommend that the Small Interruptible class receive only half of any rate increase and that the remaining increase be distributed pro rata among the other customer classes.

Q. IF THERE WERE A RATE REDUCTION, HOW SHOULD THE RATE CHANGE BE DISTRIBUTED?

A. Again consistent with Commission precedent, all classes, regardless of their rates of return, should receive a rate reduction. However, in the case of a rate reduction, the Commission can be much more aggressive in equalizing rates of return. In the 1996 NSP gas rate reduction case, the Commission accepted a proposal to reduce small and large interruptible class margins by 25 and 40 percent, respectively, and reduce the margins for the firm service classes by only 3.5 percent.[9] If the Commission reduces MDU's rates, I recommend that the rate of return for the Small Interruptible class be reduced by 40 percent, based on the alternative rate of return study summarized in Exhibit____(CWK-7), provided that this reduction allows the remaining classes to receive at least one-half the overall percentage reduction in rates.

Q. HOW DOES MDU PROPOSE THAT ITS REQUESTED RATE INCREASE BE DISTRIBUTED AMONG RATE ELEMENTS?

A. MDU proposes to increase all the customer charges significantly, even for those classes, such as the Air Force and the Large Interruptible class, that receive no overall rate change. Even though the Small Interruptible customers are to receive a rate reduction, their customer charge would increase from $35 to $100 per month. For most residential customers, the monthly customer rate would increase

[9] Case No. PU-400-95-559, decided August 7, 1996, ¶¶ 35, 43.

from $6.50 to $11.70. Small General Service customer charges would jump from $8.50 to $24.00 and large General Service charges would go from $17.00 to $51.00.

MDU witness Russell Feingold discusses the rationale for these proposals at some length. He argues that shifting revenue recovery from the commodity to the customer component allows the Company to recover much more of its fixed costs on a non-weather sensitive basis. This also protects customers from the volatility in their gas bills caused by variations in weather. During cold winters, their bills will be somewhat lower and during warm winters, they will be somewhat higher. Their winter bills, the highest of the year, will be reduced, and their small summer bills will be increased.

Q. DO YOU AGREE WITH THE COMPANY'S RATIONALE?

A. I certainly understand the Company's rationale, and I agree with the Company's statement of its effects. However, there is a matter of rate continuity to be considered. This change will result in dramatically different bills for different types of customers. For example, I suspect that very low-use customers will find the increases in their average monthly bills extortionate. Customers accustomed to low gas bills in the summer, that possibly offset high electric bills, will be surprised by the sudden jump in their gas invoices.

Customers may also resent high monthly customer charges. When most of the cost of gas is based on the level of gas consumption, customers can avoid high gas bills by conserving gas. But no amount of conservation permits a customer to avoid a monthly customer charge. As long as this charge is not a major portion of the bill, it is likely to be acceptable to most customers. But if it looms as a major element in the cost of gas, customers will come to regard it as a tax from which there is no escape. This will not enhance MDU's reputation as a public utility concerned with its customers' good will.

For these reasons, I question the advisability of such a radical restructuring of the tariff schedules. If MDU seeks to increase the customer component of its rate schedules, it should do so over a series of rate cases, not as a drastic stoke in a single rate case.

Q. HOW DO YOU RECOMMEND ANY RATE INCREASE OR DECREASE BE DISTRIBUTED BETWEEN CUSTOMER AND COMMODITY CHARGES?

A. In the case of a rate increase, I recommend that the customer charges be increased no more than twice the overall increase. This increase allowance would be in addition to the increases in customer charges that I have recommended from the flattening of the declining block rates.

If rates are reduced, I recommend that the reductions be flowed entirely into the commodity component of each rate schedule. Customer charges should not be increased when rates are reduced, except to eliminate the declining block feature of the rate schedules.

PART IV – DISTRIBUTION DELIVERY STABILIZATION MECHANISM

Q. WHAT IS THE "DISTRIBUTION DELIVERY STABILIZATION MECHANISM?"

A. This is a proposal put forth by Company witness Russell Feingold that would substitute for the increases in the customer charges should the Commission disapprove them. It is intended to modify the effects of weather variations by adjusting bills for the difference between the actual heating degree days and heating degree days under normal weather. Following a cold winter, the excess in

each class's revenue from the greater number of heating degree days would be divided by the projected annual sales volumes in that class and credited to all customers over the following year on a per-dk basis. The revenue shortfall from a warmer than normal summer would similarly be collected through a surcharge to all customers during the subsequent year.

Q. DO YOU SUPPORT THIS PROPOSAL?

A. No. I do not. The value of a weather normalization adjustment should be to ameliorate the volatility in customer bills caused by variations in weather from season to season. Of particular concern is the effect of unusually cold winters. In such winters, ratepayers typically experience a "double whammy." First, they consume more gas than usual, which increases their bills even if the price of gas remains the same. Then, because cold winters are usually a widespread phenomenon, the demand for gas is higher across the continent, which means that the price of gas is higher. The result is a further inflation in their bills. Just this sort of inflation occurred across the country during the winter of 2000-2001.

The Company's proposal could result in a "triple whammy." If North Dakota experiences an unusually warm winter, and it is followed by an unusually cold winter, ratepayers during the cold winter, already hard-hit, would find themselves paying a surcharge to make up for the shortfall in revenue collections in the previous year. The effect of the Company's program could be to increase, not decrease the volatility in customers' bills from year to year.

The objection to the Company's proposal is its delayed effect. For a weather normalization adjustment to be beneficial to ratepayers and not just the utility, it must affect their bills when the unusual weather is occurring, not after it has occurred. For this reason, I oppose the program offered by the Company.

Q. DO YOU OBJECT TO THE CONCEPT OF A WEATHER NORMALIZATION ADJUSTMENT?

A. No. A weather normalization adjustment can be beneficial to both customers and the utility if it ameliorates the impact of unusual weather. It benefits customers if winter is unusually cold and it benefits the utility if the winter is unusually warm. To be effective, however, these benefits have to flow during the unusually cold or unusually warm winters.

Q. BUT DIDN'T THE COMMISSION REJECT JUST SUCH A REAL-TIME WEATHER NORMALIZATION ADJUSTMENT WHEN MDU PROPOSED IT IN 1992?

A. Yes. The Commission rejected MDU's weather normalization adjustment partly because it was not presented in the context of a rate case and partly because it was deemed to be too complex. Since 1992, however, a number of utilities around the country have adopted weather normalization adjustments, and they have been greeted with approval not only by commissions, but by investments analysts. These adjustments are perceived as significant risk-reduction devices that reduce the cost of capital to the utility.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Charles W. King

Experience

Snavely King Majoros O'Connor & Lee, Inc. Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, earnings and depreciation. Mr. King recently directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc. Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

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Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AK	Exxon USA	P-89-1,2	Trans Alaska Pipeline System	October 18, 1990
AZ	Arizona Corporation Commission Arizona Retailers Association	U-1345-I U-1345-II	Arizona Public Service Co. Arizona Public Service Co.	December 16, 1980 January 15, 1981
CA	California Retailers Association California Retailers Association California Retailers Association California Retailers & California Manufacturers California Retailers Association	57666 57602 59351 59351 61138	Pacific Gas & Electric Co. Southern California Edison Pacific Gas & Electric Co. Southern California Edison Southern California Edison	March 6, 1978 April 25, 1978 June 12, 1981 May 20, 1982 May 28, 1982
CO	U. S. Department of Defense J.C. Penny Company U.S. Department of Defense U. S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense	I&S 1100 5693 I&S 1339 I&S 1540 C. Council C. Council C. Council C. Council	Colorado Springs (Elec) All Electric Utilities Colorado Springs DPU (Gas) Colorado Springs DPU (Gas) Colorado Springs DPU (Gas) Colorado Springs DPU (Elec) Colorado Springs DPU (Elec) Colorado Springs DPU (Elec)	June 14, 1977 March 8, 1978 October 18, 1979 February 9, 1982 September 30, 1984 June 6, 1985 May 19, 1986 June 30, 1987
CT	Retailers Merchants Association Division of Consumer Counsel Public Utilities Control Auto Division of Consumer Counsel Division of Consumer Counsel Division of Consumer Counsel Division of Consumer Counsel Coalition of Hotels, Alloys & Retailers Coalition of Hotels, Alloys & Retailers	72-0204 76-0604,5 78-0303 80-0403,4 81-0413 81-0602,4 82-0701 85-10-22 87-07-01	Various Electric Utilities CL&P and HELCO Bridgeport Hydraulic Co. CL&P and HELCO United Illuminating Company CL&P and HELCO CL&P CL&P CL&P	July 22, 1976 November 10, 1977 (none) August 11, 1980 July 20, 1981 October 5, 1981 September 28, 1982 (none) April 25, 1988

Attachment B

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
DC	D.C. People's Counsel	685	Potomac Electric Power Company	March 6, 1978
	D.C. People's Counsel	715	Potomac Electric Power Company	(none)
	D.C. People's Counsel	725	Potomac Electric Power Company	April 4, 1980
	D.C. People's Counsel	737	Potomac Electric Power Company	January 1, 1981
	Washington Metro Area Transit Authority	748	Potomac Electric Power Company	June 26, 1981
	Washington Metro Area Transit Authority	758	Potomac Electric Power Company	December 15, 1981
	D.C. People's Counsel	785	Potomac Electric Power Company	September 21, 1982
	Washington Metro Area Transit Authority	759	Potomac Electric Power Company	March 29, 1984
	D.C. People's Counsel	685 Remand	Potomac Electric Power Company	June 10, 1985
	D.C. People's Counsel	905	Potomac Electric Power Company	August 20, 1991
	D.C. People's Counsel	912	Potomac Electric Power Company	May 7, 1992
	D.C. People's Counsel	834, III	Potomac Electric Power Company	May 22, 1992
	D.C. People's Counsel	917	Potomac Electric Power Company	September 24, 1992
	D.C. People's Counsel	922	Washington Gas Light Company	June 15, 1993
	D.C. People's Counsel	929	Potomac Electric Power Company	December 16, 1993
	D.C. People's Counsel	934	Washington Gas Light Company	Filed April 22, 1994
	D.C. People's Counsel	939	Potomac Electric Power Company	March 16, 1995
	D.C. People's Counsel	917	Potomac Electric Power Company	April 16, 1995
	D.C. People's Counsel	951	Potomac Electric Power Company	February 20, 1997
	D.C. People's Counsel	945	Potomac Electric Power Company	September 29, 1999
	D.C. People's Counsel	847	Washington Gas Light Company	June 27, 2001
DE	DPSC Staff	94-164	Artesian Water Company	(none)
	DPSC Staff	94-149	Wilmington Surburban Water Company	March 10, 1995
FL	Florida Retail Federation	790593-EU	All Electric Utilities	March 5, 1981
	Florida Retail Federation	810002-EU	Florida Power and Light Company	July 23, 1981
	Florida Retail Federation	820097-EU	Florida Power and Light Company	September 22, 1982
	Florida Retail Federation	820097-EU	Florida Power and Light Company	April 11, 1983
	Florida Retail Federation	830012-EU	Tampa Electric Company	August 19, 1983
	Florida Retail Federation	830465-EI	Florida Power and Light Company	April 19, 1984
	Florida Retail Federation	830465-EI	Tampa Electric Company	(none)
GA	Georgia Retail Federation	3270-U	Georgia Power Company	September 3, 1981
	Georgia Public Service Commission	4007-U	Georgia Power Company	August 21, 1991
	Georgia Public Service Commission	4384-U	All Electric Utilities	August 1, 1993
	Georgia Public Service Commission	4755-U	Georgia Power Company	January 25, 1994
	Georgia Public Service Commission	4697-U	All Utilities	May 10, 1994
	Georgia Public Service Commission	9355-U	Georgia Power Company	November 4, 1998
	Georgia Public Service Commission	14000-U	Georgia Power Company	October 23, 2001
	Georgia Public Service Commission	14618-U	Savannah Electric & Power Company	March 27, 2002
HI	Public Utilities Department	2793	All Electric Utilities	February 14, 1978
	Hawaii Consumer Advocate	4536	Hawaiian Electric Company	February 1, 1983

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
IL	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	76-0698	Commonwealth Edison	June 22, 1977
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	76-0568	All Eletric Utilities	(none)
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	80-0546	Commonwealth Edison	March 5, 1981
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	82-0026	Commonwealth Edison	July 22, 1982
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	83-0537	Commonwealth Edison	March 19, 1984
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	87-0427	Commonwealth Edison	March/April 22, 1988
	Illinois Retail Merchants Association/	90-0169	Commonwealth Edison	October 29, 1990
IN	Indiana Retail Council	35780-S2	N. Ind. Public Service co.	June 1, 1980
	Indiana Retail Council	35780-S1	Public Service of Indiana	October 15, 1980
	Indiana Retail Council	36318	Public Service of Indiana	May 4, 1982
KS	J.C. Penny Company	115,379-U	All Kansas Utilities	January 22, 1981
KY	Seven Kentucky Retailers	7310	Louisville Gas & Electric Co.	April 25, 1979
	Kentucky Cable Telecommunications Assn.	2000-414	Blue Grass Energy Cooperative	January 11, 2001
	Kentucky Cable Telecommunications Assn.	2000-39	Cumberlant Valley Electric, Inc.	January 11, 2001
MA	Coalition of Municipalities	20279	Western Massachusetts Electric	March 19, 1980
	Coalition of Municipalities	557/558	Western Massachusetts Electric	May 14, 1981
	Coalition of Municipalities	957	Western Massachusetts Electric	March 9, 1982
	Coalition of Municipalities	1300	Western Massachusetts Electric	January 1, 1983
	Coalition of Municipalities	85-270	Western Massachusetts Electric	March 26, 1986
MD	Maryland People's Counsel	6977	Washington Gas & Light Company	September 17, 1976
	Maryland People's Counsel	6814	Potomac Electric Power Company	
	Maryland People's Counsel	6807	All Electric Utilities	September 1, 1977

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MD	Maryland People's Counsel	6882	Baltimore Gas & Electric Company	(none)
	Maryland People's Counsel	6985	Baltimore Gas & Electric Company	September 28, 1976
	Maryland People's Counsel	7070	Baltimore Gas & Electric Company	December 20, 1976
	Maryland People's Counsel	7149	Potomac Electric Power Company	April 18, 1978
	Maryland People's Counsel	7163	All Electric Utilities	January 17, 1979
	Maryland People's Counsel	7236	Delmarva Power & Light Company	October 23, 1978
	Retail Merchants of Baltimore	7397	Baltimore Gas & Electric Company	June 20, 1980
	Maryland People's Counsel	7427	Delmarva Power & Light Company	September 8, 1980
	Maryland People's Counsel	7574	Baltimore Gas & Electric Company	December 2, 1981
	Maryland People's Counsel	7597	Potomac Electric Power Company	February 18, 1982
	Organization of Consumer Justice	7604	Potomac Electric Power Company	April 20, 1982
	Maryland People's Counsel	7588	Baltimore Gas & Electric Company	October 19, 1982
	Maryland People's Counsel	7663	Potomac Electric Power Company	November 22, 1982
	Retail Merchants of Baltimore	7685	Baltimore Gas & Electric Company	April 12, 1983
	Genstar Stone Products, et al.	7878	Potomac Electric Power Company	December 9, 1985
	Industrial Intervenors	7878	Potomac Electric Power Company	June 28/July 1986
	Maryland People's Counsel	7983	Baltimore Gas & Electric Company	March 4, 1987
MI	General Services Administration	U-10102	Detroit Edison Company	March 22, 1993
	Michigan Attorney General	U-11722	Detroit Edison Company	November 6, 1998
	Michigan Attorney General	U-11772	Consumers Energy/Detroit Edison	November 16, 1998
	Michigan Attorney General	U-11495	Detroit Edison Company	December 8, 1999
	Michigan Attorney General	U-11956	Consumer Energy/Detroit Edison	December 15, 1999
	Michigan Attorney General	U-12505	Consumers Energy Company	September 7, 2000
	Michigan Attorney General	U-12478	Detroit Edison Company	October 5, 2000
	Michigan Attorney General	U-12639	Consumers Energy/Detroit Edison	July 18, 2001
	Michigan Attorney General	U-13000	Consumers Energy Company	January 29,2002
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975
ND	North Dakota Public Service Commission	PU-400-00-521	Xcel Energy, Inc.	April 20, 2001
	North Dakota Public Service Commission	PU-399-01-786	Monatan-Dakota Utilities	February 25, 2002
NH	Business & Industry Association of N.H.	79-187-II	Public Service of N.H.	February 6, 1981
	Business & Industry Association of N.H.	80-260	Public Service of N.H.	February 5, 1981
	Business & Industry Association of N.H.	82-333	Public Service of N.H.	November 2, 1983

State	Electric, Gas, Water Utility Cases			
	Client	Case		Date of Cross-Examination
		Case Number	Utlilty	
NJ	Dept. of Public Advocate	761-8	Public Service Electric & Gas	January 18, 1977
	Dept. of Public Advocate	7911-951	Atlantic City Electric Co.	April 21, 1980
	N.J. Retail Merchants Association	803-151	All New Jersey Utilities	March 31, 1981
	Department of Public Advocate	815-459	N.J. Natural Gas Company	(none)
	Resorts International Hotel, Inc.	8011-827	Atlantic City Sewerage Co.	(none)
	Dept. of Public Advocate	822-116	Atlantic City Electric Co.	August 11, 1982
	Dept. of Public Advocate	355-87	Elizabethtown Gas	June 9, 1987
	Dover Township Fire Chiefs	88-080967	Tom's River Water Company	February 22, 1989
NY	N.Y. Council of Retail Merchants	26806	All Electric Utilities	February 3, 1976
	Metropolitan N.Y. Retail Council	27029	Consolidated Edison Company	(none)
	Metropolitan N.Y. Retail Council	27136	Long Island Lighting Company	July 1, 1977
	N.Y. Metro. Transit Authority	27353	Consolidated Edison Company	September 5, 1980
OH	Ohio Council of Retail Association	88-170-EL	Cleveland Elec. Illuminating	(none)
	Ohio Council of Retail Association	83-1529-EL	Cincinnati Gas & Electric	February 15, 1992
PA	Pennsylvania Retail Association	76-PRMD-7	All Electric Utilities	September 7, 1977
	Southeastern Pa. Transp. Authority	R-811626	Philadelphia Electric Company	December 11, 1981
	Eastern Penn Energy Users Group	R-822169	Penn. Power & Light Company	March/April 1983
	Eastern Penn Energy Association	R-842651	Penn. Power & Light Company	December 3, 1984
	Penn Business Utility User Group	R-850152	Philadelphia Electric Company	February 19, 1986
	Pennsylvania Office of Consumer Advocate	R-00016339	Pennsylvania-American Water Co.	September 19, 2001
TX	Houston Retailers Association	5779	Houston Lighting Company	October 19, 1984
	Houston Retailers Association	6765	Houston Lighting Company	September 25, 1986
	Cities for Fair Utility Rates	8425/8431	Houston Lighting Company	April 25, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
UT	Div. Of Public Utilities Dept of Commerce	98-2035-33	Pacific Corp	Filed August 16, Sept 22, 1999
VA	Consumer Congress of Virginia Consumer Congress of Virginia Va. Business Committee on Energy Virginia Pipe Trades Council	19426 19960 PUE 7900012 PUE 8900051	Virginia Electric Power Company Virginia Electric Power Company Virginia Electric Power Company Old Dominion Electric Corp. &	July 1, 1975 September 19, 1978 February 25, 1981 October 31, 1989
WI	Wisconsin Merchants Federation	6630-ER-2	Wisconsin Electric Power Company	May 15, 1978

State	Telecommunications Cases			
	Client	Case		Date of Cross-Examination
		Case Number	Utlilty	
AL	U.S. Department of Defense	24472	All Telephone Companies	June 14, 1995
AZ	Arizona Burglar & Fire Alarm Association	9981-E-1051-80-64	Mountain State Telephone	(none)
	Federal Executive Agencies	E-1051-88-146	Mountain State Telephone	(none)
	U.S. Department of Defense	T-01051B-99-0105	US WEST Communications	Filed July 26, Sept 8, 2000
CA	Western Burglar & Fire Alarm Association	59849	Pacific Telephone & Telegraph	March 25, 1981
	Western Burglar & Fire Alarm Association	5984cont.	Pacific Telephone & Telegraph	June 23, 1982
	Western Burglar & Fire Alarm Association	A83-01-22	Pacific Telephone & Telegraph	June 29, 1983
	Western Burglar & Fire Alarm Association	A83-02-02	General Telephone of California	January 17, 1984
	Western Burglar & Fire Alarm Association	A82-11-07	Pacific Telephone & Telegraph	Jan. 18, Oct. 31 November 28, 1984
	Western Burglar & Fire Alarm Association	A85-01-034	Pacific Telephone & Telegraph	June 4, 1985 October 2, 1986
	Western Burglar & Fire Alarm Association	A87-01-02	General Telephone of California	October 22, 1987
	Western Burglar & Fire Alarm Association	A88-07-17019	Pac. Bell Tel. & GTE of CA.	January 23, 1989
	California Cellular Resellers	A.88-11-1040	All Cellular Carriers	August 11, 1989
	Federal Executive Agencies	1.87-11-033	All Telephone Companies	March 6-7, 1991
	California Cellular Resellers	1.88-11-040	All Cellular Carriers	August 19, 1991
	Cellular Services, Inc.	1.88-11-040	All Cellular Carriers	October 3, 1991
	Federal Executive Agencies	A92-05-004	Pacific Telephone & Telegraph	June 9, 1993
CO	U.S. Department of Defense	I&S 717	Mountain Bell Telephone Company	1972
	U.S. Department of Defense	I&S 1700	Mountain Bell Telephone Company	(none)
	U.S. Department of Defense	Appl.	Mountain Bell Telephone Company	September 18, 1986
	U.S. Department of Defense	I&S 1766	Mountain Bell Telephone Company	November 28, 1988
	Colorado Municipal League	Appl 36883	Mountain Bell Telephone Company	December 13, 1988
	U.S. Department of Defense	I&S 891-O82T	U.S. West Communications	February 21, 1990
	U.S. Department of Defense	905-544T	U.S. West Communications	July 17, 1991
	U.S. Department of Defense	90A-665T	U.S. West Communications	October 23, 1991
	U.S. Department of Defense	92M-039T	U.S. West Communications	February 24-24, 1992
	U.S. Department of Defense	92S-229T	U.S. West Communications	July 30-31, 1992
	U.S. Department of Defense	90A-665T	U.S. West Communications	November 6, 1996
	AT&T	96S-331T	U.S. West Communications	April 17, 1997

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
CT	Connecticut Consumer Counsel	770526	Southern New England Telephone Co.	November 10, 1977
	CT Cellular Resellers Assn.	89-12-05	Southern New England Telephone Co.	(none)
	CT Cellular Resellers Coalition	94-03-27	Springwich Cellular/Bell Atlantic	May 16, June, 1994
	AT&T	AT&T/SNET Arbitration	Southern New England Telephone Co.	Filed October 28, 1996
	Connecticut Consumer Counsel	96-04-07	Southern New England Telephone Co.	February 10,1998
	Connecticut Consumer Counsel	00-07-17	Southern New England Telephone Co.	December 5, 2000
DC	D.C. People's Counsel	729	Chesapeake & Potomac Tel. Co.	May 13, 1980
	D.C. People's Counsel	798	Chesapeake & Potomac Tel. Co.	July 18, 1983
	General Services Administration	827	Chesapeake & Potomac Tel. Co.	May 7, 1985
	General Services Administration	854	Chesapeake & Potomac Tel. Co.	April 16, 1987
	General Services Administration	850	Chesapeake & Potomac Tel. Co.	October 7, 1991
	General Services Administration	926	Chesapeake & Potomac Tel. Co.	October 7, 1993
DE	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	April 1, 1985
	Federal Executive Agencies	86-20	Diamond State Telephone Co.	July 31, 1987
	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	March 8, 1988
FL	GTE Sprint Communications Company	720536-TP	All Telephone Companies	September 12, 1983
	Office of Public Counsel	Depr.Repre	Southern Bell	July 30, 1986
	Federal Executive Agencies	880069-TL	Southern Bell	July 21, 1988
	Federal Executive Agencies	880069-TL	Southern Bell	November 30, 1990
	Federal Executive Agencies	880069-TL	Southern Bell	February 11, 1992
GA	Georgia Attorney General	3893-U	Southern Bell Telephone Co.	January 8, 1990
	Federal Executive Agencies	3905-U	Southern Bell Telephone Co.	June 12, 1990
	Federal Executive Agencies	3987-U	Southern Bell Telephone Co.	February 13, 1992
	Georgia Public Service Commission	4018-U	Southern Bell Telephone Co.	Jan 14, Feb 10, 1993
HI	Hawaii Public Utility Commission	1871	Hawaiian Telephone Company	July 8, 1971
	Four Hawaii Counties	4588	Hawaiian Telephone Company	December 15, 1983
	Department of Defense	7579	Hawaiian Telephone Company	April 26, 1994
	Department of Defense	94-0093	Oceanic Communications	March 13, 1995
	Department of Defense	7702	All Communications Carriers	June 2, 1995
	Department of Defense	94-0298	GTE Hawaiian Telephone Company	May 7, 1996
	Department of Defense	7720	Verizon-Hawaii	November 15, 2000

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
ID	U.S. Department of Energy U.S. Department of Energy	U-1000-63 U-1000-70	Mountain Bell Telephone Co. Mountain Bell Telephone Co.	May 16, 1983 March 6, 1984
IL	Illinois Aalarm Companies Attorney Generaal of Illinois GTE Sprint Communications Co. Federal Executive Agencies	79-0143 81-0478 83-0142 89-0033	Illinois Bell Telephone Illinois Bell Telephone All Telephone Companies Illinois Bell Telephone	September 26, 1979 December 28, 1981 August 4, 1983 June 12, 1989
KS	State Corporation Commission Federal Executive Agencies Federal Executive Agencies	Depr. Repr. 166.856-U 190, 492	Southwestern Bell Southwestern Bell All Telephone Companies	May 12-14, 1986 November 7, 1989 November 4, 1994
MD	Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Federal Executive Agencies Federal Executive Agencies Federal Executive Agencies	6813 6881 7025 7467 7851 8106 8274	C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company	1975 December 17, 1975 March 15, 1975 October 20, 1981 March 20, 1985 May 9, 1988 August 2, 1990
MI	Michigan Attorney General Michigan Attorney General	U-8911 U-9553	Michigan Bell Telephone Co. AT&T Communications/MCI	November 7, 1988 December 4, 1990
MN	GTE Sprint Communications Co. U.S. Department of Defense	83-102-HC 87-021-BC	All Telephone Companies Northwest Bell Telephone Co.	August 5, 1983 (none)
MO	GTE Sprint Communications Co. Federal Executive Agencies Federal Executive Agencies	TR83-253 TC-89-14 TO-89-56	Southwestern Bell Tel. Co. Southwestern Bell Tel. Co. Southwestern Bell Tel. Co.	September 5, 1983 (none) November 7, 1990
MS	Federal Executive Agencies	U-5453	South Central Bell Tel. Co.	May 15, 1990

State	Telecommunications Cases			
	Client	Case		Date of Cross-Examination
		Case Number	Utility	
NJ	Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate	Depr.Repr. 815-458 Depr.Repr. Depr.Repr. T092030358	N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company	Mar-79 October 15, 1981 March 1, 1982 February 1, 1985 September 30, 1992
NM	New Mexico Corporation Commission New Mexico Corporation Commission	1032 86-151-TC	Mountain Bell Telephone Co. General Telephone of Southwest	November 14, 1983 February 5, 1987
NV	Prime Cable of Las Vegas Prime Cable of Las Vegas	95-8034/8035 96-9035	Central Telephone - NV Sprint/Centel, Nevada Bell	Filed November 22, 1995 June 2, 1997
NY	Holmes Protection, Inc. Holmes Protection, Inc. 5 Alarm Companies GTE Sprint Communications Co.	27350 27469 27710 28425	New York Telephone Company New York Telephone Company New York Telephone Company All Telephone Companies	October 17, 1978 May 17, 1979 July 24, 1980 July 8, 1983
PA	City of Philadelphia	R-832316	Pennsylvania Bell Telephone	September 20, 1983
SC	Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate	Depr.Repr. 86-511-C 86-541-C Depr.Repr. 89-180-C	Southern Bell Southern Bell General Telephone of South Southern Bell ALLTEL of South Carolina	July 1, 1986 December 11, 1986 April 8, 1987 July 10, 1989 September 26, 1989
TX	U.S. Department of Defense	8585/8218	Southwestern Bell Telephone Co.	(none)
VA	U.S. Dept. Of Defense, GSA, et Federal Executive Agencies	19696 PUC 890014	C&P Telephone Company All Telephone Companies	October 6, 1976 February 13, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
VI	V.I. Department of Commerce	205	Virgin Islands Telephone Co.	April 29, 1980
	V.I. Public Service Commission	341	Virgin Islands Telephone Co.	March 20, 1991
WA	U.S. Department of Defense	U-72-39	Pacific Northwest Bell	1973
	U.S. Department of Defense	U-87-796-T	Pacific Northwest Bell	December 20, 1983
	U.S. Department of Defense	U-88-20524	Pacific Northwest Bell	November 8, 1988
	U.S. Department of Defense	U-89-2698-F	US West Communications	November 28, 1989
	WA Attorney General/TRACER	UT-940641	US West Communications	Filed October 14, 1994
	U.S. Department of Defense	UT-941464	US West Communications	June 22, 1995
	U.S. Department of Defense		US West Communications	January 22, 1996
	WA Attorney General/TRACER	UT-951425	US West Communications	Filed June 23, 1997
	WA Attorney General/TRACER	UT-961632	GTE Northwest, Inc	July 29, 1997
WI	GTE Sprint	6720-TR-38	All Telephone Companies	October 20, 1983
	Wisconsin Consumers Utility Board	2055-TR-102	CenturyTel of Central Wisconsin	June 26, 2002
	Wisconsin Consumers Utility Board	5846-TR-102	Telephone USA, LCC	June 26, 2002

Client	Docket	Subject	Date of Cross-Examination
Federal Communications Commission			
Department of Defense	16020	Consat Rate of Return	1973
Airline Parties	16258	Bell System Rates	July 22, 1968
Airline Parties	18128	TELPAK	3/22, 10/15 1971, Feb. 22, 1972
National Data Corporation	19989	WATS	(none)
Press Wire Services	19919	Private Line Rates	(none)
Aeronautical Radio	20814	Private Line Rates	October 5, 1978
Department of Defense	20690	1,544 Mbps Service	January 30, 1979
State of Hawaii	21263	Interstate Separation	February 7, 1979
International Record Carriers	CC78-97	Telex/TWX Rates	March 6, 1980
ITT World Communications	CC84-633	Rate of Return	(none)
Aeornautical Radio	CC78-72	Access Line Charges	(none)
MCI	CC84-800	Rate of Return	(none)
Ind. Data Com. Mfg. Assn.	CC85-26	AT&T Accounting Plan	(none)
Tymnet, Inc.	ENF84-22	Packet Switching Costs	(none)
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 7/29/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 8/23/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 2/21/95
Nuclear Regulatory Commission			
Fauquier League for Environment Protection	50-328 50-329	Va. Electric Power Co.	1976
Postal Rate Commission			
Association of Third Class Mail Users	R71-1	Rates	1970
Dow Jones & Company	R72-1	Rates	1972
Dow Jones & Company	R74-1	Rates	September 13, 1974
Dow Jones & Company	MC76-2	Rate Structure	January 6, 1979
Dow Jones & Company	MC79-3	Rate Structure	September 12, 1979
Dow Jones & Company	R80-1	Rates	November 25, 1980
Warshawsky & Company	C82-1	Rate Structure	(none)
Dow Jones & Company	R84-1	Postal Costs	June 14, 1984
Dow Jones & Company	R87-1	Rate Structure Costs	November 2, 1987
Dow Jones & Company	R90-1	Rate Structure Costs	Sept 12, Oct 10, 1990
Dow Jones & Company	MC91-1	Pre-barcoding Discounts	November 19, 1991
Dow Jones & Company	MC91-3	Palletization Discounts	March 2, 1992

CHARLES W. KING
Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date of Cross-Examination
U.S. Congress			
National Retail Merchants Association	House/Senate Hearings	Electric Rate Reform Legislation	1976, 1977 & 1979
National Wireless Resellers Association	House Commerce Committee	Interconnection & Resale of Wireless Services	October 12, 1995
Federal Maritime Commission			
State of Hawaii	71-18	Ocean Shipping Rates	October-71
Foss Alaska Line	79-54	Barge Rate Increase	July 1979
Palmetto Shipping and Stevadoring	85-20	Vessel Charge Liability	October 27, 1986
Interstate Commerce Commission			
Western Coal Traffic League	Ex Parte 349	R.R. Rate Increase	May-76
Western Coal Traffic League	Ex Parte 357	R.R. Rate Increase	Oct-78
Western Coal Traffic League	Ex Parte 375 (Sub1)	R.R. Rate Increase	June 1, 1980
Arkansas Power & Light Co.	37276	Cost of Capital	(none)
Central Illinois Light Co.	37450	Cost of Capital	March 10, 1981
Western Coal Traffic League	Ex Parte 347	Costing Methods	(none)
Civil Aeronautics Board			
Thomas Cook, Inc.	36595	Air Fare Deregulation	(none)
Copyright Royalty Tribunal			
Public Broadcasting Service	88-2-86CD	Television Valuation	(none)
Federal Energy Regulatory Commission			
Exxon USA	OR89-2-000	Pipeline Quality Bank	October 18, 1990
Canadian Transport Commission			
Rail Costing Inquiry, 1967-1969 Telecommunications Costing Inquiry, 1972-1975			
Surface Transportation Board			
Williams Energy Services, Inc	Ex Parte 582, Sub 1	Rail Merger Guidelines	April 5, 2001

MONTANA-DAKOTA UTILITIES CO.
FIRST DATA REQUESTS
CHARLES KING ON BEHALF OF THE NORTH DAKOTA
PUBLIC SERVICE COMMISSION STAFF
DATED JULY 25, 2002
CASE NO. PU-399-02-183

Request No. 3 Reference: Statements A-F, G-L, N-O.

See Statement A. State the amount of short-term borrowings by MDU Utilities Co. and MDU Resources, Inc, respectively at the end of each month in 2000 and 2001. Identify the weighted average cost of MDU Utilities' short-term borrowing.

Response:

Please see Attachment A for Montana-Dakota's short-term borrowings. Please see Attachment B for the short-tem borrowings for MDU Resources Group, Inc. Attachment B is considered "Trade Secret" material by the Company and an Application For Trade Secret Protection has been filed with the Commission. The material will be available for review following a Commission decision.

MONTANA-DAKOTA UTILITIES CO.
COMMERCIAL PAPER BORROWINGS
2001

F:\GENACT\HEIDJ\CONTROLS\[COMPAPER.xlw]2001 RECAP

					{----------CURRENT MONTH----------}		
AMOUNT	ISSUANCE DATE	MATURITY DATE	DAYS O/S	INTEREST RATE	DAYS O/S	MONTHLY TOTAL	INTEREST EXPENSE
January-01							
8,000,000	12/29	1/3	5	0.06600	2	16,000,000	2,933.33
10,000,000	1/2	1/10	8	0.06600	8	80,000,000	14,666.67
10,000,000	1/2	1/17	15	0.06570	15	150,000,000	27,375.00
10,000,000	1/2	1/24	22	0.06530	22	220,000,000	39,905.56
10,000,000	1/2	1/31	29	0.06500	29	290,000,000	52,361.11
5,000,000	1/3	1/31	28	0.06450	28	140,000,000	25,083.33
4,000,000	1/17	2/7	21	0.06050	15	60,000,000	10,083.33
5,000,000	1/24	2/14	21	0.05820	8	40,000,000	6,466.67
15,000,000	1/25	2/21	27	0.05680	7	105,000,000	16,566.67
9,000,000	1/31	2/28	28	0.05550	1	9,000,000	1,387.50
	1/31	1/31	Rounding correction				0.01
						1,110,000,000	$196,829.18
						/ 31 DAYS	
						$35,806,451.61	
		AVERAGE SHORT-TERM RATE (%) -JANUARY 2001				6.472	
February-01							
4,000,000	1/17	2/7	21	0.06050	6	24,000,000	4,033.33
5,000,000	1/24	2/14	21	0.05820	13	65,000,000	10,508.33
15,000,000	1/25	2/21	27	0.05680	20	300,000,000	47,333.33
9,000,000	1/31	2/28	28	0.05550	27	243,000,000	37,462.50
8,000,000	2/26	3/7	9	0.05540	3	24,000,000	3,693.33
9,000,000	2/28	3/14	14	0.05500	1	9,000,000	1,375.00
	2/28	2/28	Rounding correction				0.00
						665,000,000	$104,405.82
						/ 28 DAYS	
						$23,750,000.00	
		AVERAGE SHORT-TERM RATE (%) -FEBRUARY 2001				5.731	
March-01							

MONTANA-DAKOTA UTILITIES CO.
COMMERCIAL PAPER BORROWINGS
2001

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AMOUNT	ISSUANCE DATE	MATURITY DATE	DAYS O/S	INTEREST RATE	{----------CURRENT MONTH----------} DAYS O/S	MONTHLY TOTAL	INTEREST EXPENSE
8,000,000	2/26	3/7	9	0.05540	6	48,000,000	7,386.67
9,000,000	2/28	3/14	14	0.05500	13	117,000,000	17,875.00
2,000,000	3/1	3/2	1	0.05670	1	2,000,000	315.00
4,000,000	3/2	3/21	19	0.05530	19	76,000,000	11,674.44
2,000,000	3/26	3/30	4	0.05050	4	8,000,000	1,122.22
	3/31	3/31	Rounding correction				0.00
						251,000,000	$38,373.33
						/ 31 DAYS	
						$8,096,774.19	
			AVERAGE SHORT-TERM RATE (%) - MARCH 2001			5.580	

1ST QUARTER

						2,026,000,000	$339,608.33
						/ 90 DAYS	
						$22,511,111.11	
			AVERAGE SHORT-TERM RATE (%) - 1ST QUARTER 2001			6.118	

April-01

3,000,000	4/2	4/11	9	0.05200	9	27,000,000	3,900.00
	4/30	4/30	Rounding correction				0.00
						27,000,000	$3,900.00
						/ 30 DAYS	
						$900,000.00	
			AVERAGE SHORT-TERM RATE (%) - APRIL 2001			5.272	

May-01

	5/31	5/31	Rounding correction				0.00
						0	$0.00
						/ 31 DAYS	

MONTANA-DAKOTA UTILITIES CO.
COMMERCIAL PAPER BORROWINGS
2001

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					{----------CURRENT MONTH----------}		
AMOUNT	ISSUANCE DATE	MATURITY DATE	DAYS O/S	INTEREST RATE	DAYS O/S	MONTHLY TOTAL	INTEREST EXPENSE
						$0.00	
	AVERAGE SHORT-TERM RATE (%) - MAY 2001					0.000	
June-01							
	6/30	6/30	Rounding correction				0.00
						0	$0.00
						/ 30 DAYS	
						$0.00	
	AVERAGE SHORT-TERM RATE (%) -JUNE 2001					0.000	
2ND QUARTER							
						27,000,000	$3,900.00
						/ 91 DAYS	
						$296,703.30	
	AVERAGE SHORT-TERM RATE (%) - 2ND QUARTER 2001					5.272	
YEAR-TO-DATE							
						2,053,000,000	$343,508.33
						/ 181 DAYS	
						$11,342,541.44	
	AVERAGE SHORT-TERM RATE (%) - YEAR TO DATE 2001					6.107	
July-01							
2,000,000	7/25	8/1	7	0.03850	7	14,000,000	1,497.22
	7/31	7/31	Rounding correction			0	0.00
						14,000,000	$1,497.22
						/ 31 DAYS	

MONTANA-DAKOTA UTILITIES CO.
COMMERCIAL PAPER BORROWINGS
2001

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AMOUNT	ISSUANCE DATE	MATURITY DATE	DAYS O/S	INTEREST RATE	{----------CURRENT MONTH----------} DAYS O/S	MONTHLY TOTAL	INTEREST EXPENSE
						$451,612.90	
	AVERAGE SHORT-TERM RATE (%) -JULY 2001					3.903	
August-01							
3,000,000	8/24	8/29	5	0.03580	5	15,000,000	1,491.67
3,000,000	8/29	9/5	7	0.03700	3	9,000,000	925.00
	8/31	8/31	Rounding correction				0.00
						24,000,000	$2,416.67
						/ 31 DAYS	
						$774,193.55	
	AVERAGE SHORT-TERM RATE (%) - AUGUST 2001					3.675	
September-01							
3,000,000	8/29	9/5	7	0.03700	4	12,000,000	1,233.33
3,000,000	9/5	9/12	7	0.03700	7	21,000,000	2,158.33
4,000,000	9/25	9/28	3	0.03150	3	12,000,000	1,050.00
	9/30	9/30	Rounding correction				0.00
						45,000,000	$4,441.66
						/ 30 DAYS	
						$1,500,000.00	
	AVERAGE SHORT-TERM RATE (%) - SEPTEMBER 2001					3.603	
3RD QUARTER							
						83,000,000	8,355.55
						/ 92 DAYS	
						$902,173.91	

MONTANA-DAKOTA UTILITIES CO.
COMMERCIAL PAPER BORROWINGS
2001

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AMOUNT	ISSUANCE DATE	MATURITY DATE	DAYS O/S	INTEREST RATE	CURRENT MONTH DAYS O/S	CURRENT MONTH MONTHLY TOTAL	CURRENT MONTH INTEREST EXPENSE
		AVERAGE SHORT-TERM RATE (%) - 3RD QUARTER 2001				3.674	
YEAR-TO-DATE							
						2,136,000,000	351,863.88
						/ 273 DAYS	
						$7,824,175.82	
		AVERAGE SHORT-TERM RATE (%) - YEAR TO DATE 2001				6.013	
October-01							
6,000,000	10/1	10/3	2	0.03250	2	12,000,000	1,083.33
4,000,000	10/3	10/10	7	0.02650	7	28,000,000	2,061.11
1,000,000	10/9	10/10	1	0.02650	1	1,000,000	73.61
4,000,000	10/10	10/17	7	0.02650	7	28,000,000	2,061.11
2,000,000	10/17	10/24	7	0.02650	7	14,000,000	1,030.56
1,000,000	10/19	10/24	5	0.02600	5	5,000,000	361.11
4,000,000	10/22	10/31	9	0.02550	9	36,000,000	2,550.00
3,000,000	10/24	11/7	14	0.02550	8	24,000,000	1,700.00
3,000,000	10/25	11/7	13	0.02550	7	21,000,000	1,487.50
15,000,000	10/30	11/15	16	0.02520	2	30,000,000	2,100.00
2,000,000	10/31	11/15	15	0.02520	1	2,000,000	140.00
	10/31	10/31	Rounding correction			0	0.00
						201,000,000	$14,648.33
						/ 31 DAYS	
						$6,483,870.97	
		AVERAGE SHORT-TERM RATE (%) - OCTOBER 2001				2.660	
November-01							
3,000,000	10/24	11/7	14	0.02550	6	18,000,000	1,275.00
3,000,000	10/25	11/7	13	0.02550	6	18,000,000	1,275.00

MONTANA-DAKOTA UTILITIES CO.
COMMERCIAL PAPER BORROWINGS
2001

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					{----------CURRENT MONTH----------}		
	ISSUANCE	MATURITY	DAYS	INTEREST	DAYS	MONTHLY	INTEREST
AMOUNT	DATE	DATE	O/S	RATE	O/S	TOTAL	EXPENSE
15,000,000	10/30	11/15	16	0.02520	14	210,000,000	14,700.00
2,000,000	10/31	11/15	15	0.02520	14	28,000,000	1,960.00
250,000	11/7	11/21	14	0.02100	14	3,500,000	204.17
2,750,000	11/7	11/21	14	0.02100	14	38,500,000	2,245.83
14,000,000	11/15	11/29	14	0.02150	14	196,000,000	11,705.56
6,000,000	11/21	12/5	14	0.02250	10	60,000,000	3,750.00
14,000,000	11/29	12/12	13	0.02120	2	28,000,000	1,648.89
	11/30	11/30	Rounding correction			0	0.00
						600,000,000	$38,764.45
						/ 30 DAYS	
						$20,000,000.00	
			AVERAGE SHORT-TERM RATE (%) - NOVEMBER 2001			2.358	

December-01

6,000,000	11/21	12/5	14	0.02250	4	24,000,000	1,500.00
14,000,000	11/29	12/12	13	0.02120	11	154,000,000	9,068.89
4,000,000	12/5	12/19	14	0.02100	14	56,000,000	3,266.67
10,000,000	12/12	12/28	16	0.01930	16	160,000,000	8,577.78
2,000,000	12/17	12/31	14	0.02000	14	28,000,000	1,555.56
2,000,000	12/18	12/31	13	0.01900	13	26,000,000	1,372.22
2,000,000	12/19	12/31	12	0.01900	12	24,000,000	1,266.67
9,000,000	12/21	12/31	10	0.01950	10	90,000,000	4,875.00
6,500,000	12/28	12/31	3	0.02050	3	19,500,000	1,110.42
	12/31	12/31	Rounding correction			0	0.00
						581,500,000	$32,593.21
						/ 31 DAYS	
						$18,758,064.52	
			AVERAGE SHORT-TERM RATE (%) - DECEMBER 2001			2.046	

MONTANA-DAKOTA UTILITIES CO.
COMMERCIAL PAPER BORROWINGS
2001

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					{----------CURRENT MONTH----------}		
AMOUNT	ISSUANCE DATE	MATURITY DATE	DAYS O/S	INTEREST RATE	DAYS O/S	MONTHLY TOTAL	INTEREST EXPENSE
4TH QUARTER							
						1,382,500,000	86,005.99
						$15,027,173.91	
AVERAGE SHORT-TERM RATE (%) - 4TH QUARTER 2001						2.271	
YEAR-TO-DATE							
						3,518,500,000	437,869.87
						/ 365 DAYS	
						$9,639,726.03	
AVERAGE SHORT-TERM RATE (%) - YEAR TO DATE 2001						4.542	

MDU Resources Group, Inc.
Long-term Debt Outstanding
December 31, 2001

	Principal Outstanding	Cost Rate	Annual Cost
First Mortgage Bonds			
Secured Medium-term Notes			
8.25%	$ 30,000,000	10.177%	$ 3,053,100
8.60%	35,000,000	11.020%	3,857,000
6.52%	15,000,000	7.811%	1,171,650
6.71%	15,000,000	8.195%	1,229,250
5.83%	15,000,000	6.068%	910,200
			-
Pollution Control Revenue Bonds			-
Mercer County	15,000,000	7.288%	1,093,200
Richland County	3,250,000	7.243%	235,398
Morton County	2,600,000	7.344%	190,944
Senior Notes	405,200,000	7.340%	29,741,680
			-
Commercial Paper	$ 219,700,000	2.430%	5,338,710
			-
Revolving Line of Credit	$ 25,000,000	4.750%	1,187,500
			-
Term Credit Agreements	$ 11,769,000	7.380%	868,552
			-
Pollution Control Note Obligation	$ 2,500,000	6.200%	155,000
Discount	$ (225,000)	6.200%	(13,950)
Total Long-term Debt	$ 794,794,000	**6.167%**	$ 49,018,234

Sources: Statement F, Schedule F-1, page 4
Statement A, pages 11, 12

List of Comparison Companies

Company	Gas Distribution Revenue	Total Revenue	Gas Distribution Percent	Moody's Rating	S&P's Rating
Atmos Energy Corp.	1,378	1,442	95.6%	A3	A-
AGL Resources	914	1,049	87.1%	A3	A-
Cascade Natural Gas Corp.	336	336	100.0%	Baa1	BBB+
LaClede Group, Inc.	930	1,002	92.8%	Aa3	AA-
NICOR, Inc.	2,121	2,544	83.4%	A2	AA
Northwest Natural Gas Co.	636	650	97.8%	A2	A
People's Energy Corp.	1,835	2,270	80.8%	Aa2	AA-
Piedmont Natural Gas Co.	1,108	1,108	100.0%	A2	A
South Jersey Industries, Inc.	837	837	100.0%*	Baa1	BBB+
Southwest Gas	1,193	1,397	85.4%	Baa1	BBB-
WGL Holdings, Inc.	1,447	1,940	74.6%	Aa2	AA-
Average	1,158	1,325	90.7%	Aa2	A

*Includes wholesale gas operations

Book Value Growth Model
Comparison Gas Distribution Companies

Value Line Forecasts	1/ Earnings per Share (1)	1/ Dividends per Share (2)	2/ Earnings Retention (3)	1/ Return on Book (4)	3/ Book Value Growth (5)	1/ Shares 2002 (6)	1/ Shares 2006 (7)	4/ Annual Growth Rate (8)	5/ 2001 Book Value (9)	6/ 50 Day Avg. Market Price (10)	7/ % Mkt Over Book (11)	8/ Share Sales Increment (12)	9/ Total "g" Factor (13)	Dividend Yield (14)	10/ DCF Return (15)
Atmos Energy Corp.	2.20	1.30	40.9%	14.0%	5.73%	42.00	50.00	5.98%	14.31	$ 21.63	51.2%	3.06%	8.79%	5.63%	14.42%
AGL Resources	2.10	1.16	44.8%	13.0%	5.82%	56.00	57.00	0.59%	12.19	$ 21.76	78.5%	0.46%	6.28%	5.25%	11.53%
Cascade Natural Gas Corp.	2.00	0.98	51.0%	15.5%	7.91%	11.05	12.00	2.79%	11.01	$ 19.69	78.8%	2.20%	10.10%	5.00%	15.11%
LaClede Group, Inc.	2.25	1.45	35.6%	12.0%	4.27%	18.90	20.00	1.90%	15.26	$ 22.65	48.4%	0.92%	5.19%	6.04%	11.23%
NICOR, Inc.	4.40	2.24	49.1%	21.5%	10.55%	44.25	43.00	0.00%	16.13	$ 35.06	117.4%	0.00%	10.55%	5.41%	15.96%
Northwest Natural Gas Co.	2.60	1.35	48.1%	11.5%	5.53%	25.50	25.50	0.00%	18.56	$ 28.28	52.4%	0.00%	5.53%	4.59%	10.12%
People's Energy Corp.	4.30	2.24	47.9%	12.0%	5.75%	35.00	32.00	0.00%	22.75	$ 34.00	49.5%	0.00%	5.75%	6.33%	12.07%
Piedmont Natural Gas Co.	2.85	1.82	36.1%	12.5%	4.52%	33.00	35.00	1.98%	17.26	$ 34.45	99.6%	1.97%	6.49%	4.75%	11.24%
South Jersey Industries, Inc.	3.00	1.58	47.3%	11.5%	5.44%	12.30	13.50	3.15%	18.57	$ 32.85	76.9%	2.42%	7.87%	4.70%	12.57%
Southwest Gas	2.20	0.88	60.0%	8.0%	4.80%	33.00	33.00	0.00%	17.27	$ 22.79	32.0%	0.00%	4.80%	3.72%	8.52%
WGL Holdings, Inc.	2.45	1.30	46.9%	12.5%	5.87%	48.50	48.50	0.00%	16.24	$ 24.21	49.1%	0.00%	5.87%	5.34%	11.21%
					6.02%							1.00%	7.02%	5.16%	12.18%

1/ Value Line Company Reports 2005 - 2007
2/ (3) = 1-((2)/(1))
3/ (5) = (3) * (4)
4/ (8) = (((7)/(6))^1/3)-1
5/ Value Line Company Reports
6/ CBS MarketWatch
7/ (11) = ((10)/(9))-1
8/ (12) = (8) * (11)
9/ (13) = (5) + (12)
10/ (15) = (13) + (14)

The Whole Enchilada

Zacks
Investment
Research, Inc.
-Company Reports-

LACLEDE GRP INC

Ticker	**LG**	**Shares/ Outstanding**	**18.9 MM**
Exchange	**NYSE**		
Industry	**UTIL-GAS DISTR**		
Type	**Small**	**Institutions**	**23.66%**
		Insiders	

The Laclede Group, Inc. is a public utility engaged in the retail distribution and transportation of natural gas. The Company, which is subject to the jurisdiction of the Missouri Public Service Commission, serves the City of St. Louis, St. Louis County, the City of St. Charles, St. Charles County, the town of Arnold, and parts of Franklin, Jefferson, St. Francois, Ste. Genevieve, Iron, Madison and Butler Counties, all in Missouri.

Rec Price	P/E	Mkt Cap	Div Rate	Yield	Sales (12Mo)	Sls Gr	EPS Gr	Div Gr	Zacks Rank
$23.70	19.9	$447 MM	$1.34	5.7%	$721 MM	12%	-5%	0%	Hold

Price/Volume Data

52 Week High	$25.00
52 Week Low	$19.45
Price Change-Year To Date	-1%
Year To Date(Relative To S & P 500)	-23%
Average Daily Volume	29,000s
Beta	0.03

Wall Street Recommendations

	Natl Retail Broker	Inst Broker	Reg Broker	Total	Z Indicator
Strong Buy	1	0	0	1	0
Strong Buy Changes: *increase, 1 week*					
Moderate Buy	0	0	0	0	0
Mod Buy Changes: *increase, 1 week* *decrease, 1 week*					
Hold	1	0	0	1	1
Hold Changes: *increase, 1 week* *decrease, 1 week*					
Moderate Sell	0	0	0	0	0
Mod Sell Changes: *increase, 1 week* *decrease, 1 week*					
Strong Sell	0	0	0	0	0
Strong Sell Changes: *decrease, 1 week*					

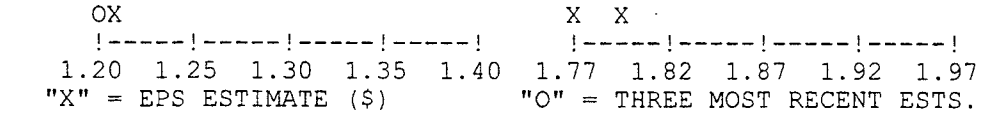
Estimates and actuals are both EPS before extras and other non-recurring items

DISTRIBUTION OF EPS ESTIMATES
HISTOGRAM AS OF 08/18/02

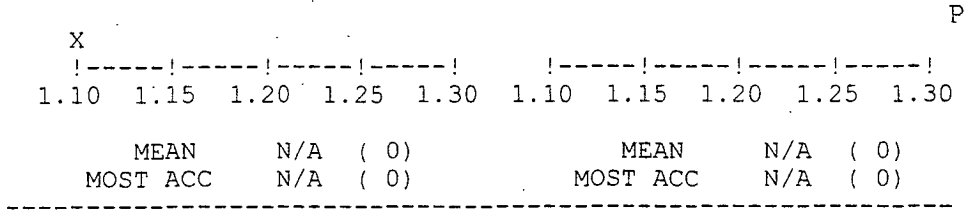
LACLEDE GRP INC

FY1 - 0209
2 ESTS.

FY2 - 0309
2 ESTS.



03/02 QTR: LACLEDE GRP INC 06/02 QTR:
REPT DATE: 04/25/02 * EXP.REPT: 07/25/02



Current EPS Estimates

Period	Ending	Mean Est. ($/SH)	High Est. ($/SH)	Low Est. ($/SH)	Number Ests.	Mean Change, Last Month ($)
Year Ending	09/03	1.78	1.80	1.77	2	0.00
Year Ending	09/02	1.21	1.21	1.20	2	0.00
VS Actual	09/01	1.61				
Quarter End	06/02	N/A	N/A	N/A	0	N/A
VS Actual	06/01	-0.20				
Quarter End	09/02	-0.31	-0.31	-0.31	1	0.00
VS Actual	09/01	-0.27				
Next 5 Year Growth (%)		4.25	4.50	4.00	2	-0.25

Surprise History

Quarter End	% Surprise	Actual	Estimate	Std Dev	# Analysts
03/02	N/A	1.10	N/A	N/A	0
12/01	-44.59	0.41	0.74	N/A	1
09/01	3.57	-0.27	-0.28	N/A	1

Financial History

Year End	Sales	Net Income	EPS ex NRI	EPS Reported	Dividends	High	Low
2001	N/A	N/A	1.61	1.61	N/A	25	21
2000	N/A	N/A	1.37	1.37	N/A	23	19
1999	N/A	N/A	1.43	1.43	N/A	24	20

EPS History

Fiscal Year	1st Q	2nd Q	3rd Q	4th Q	Year
2003	0.90E	1.20E	N/A	-0.30E	1.78E
2002	0.41	1.10	-0.05	-0.31E	1.21E
2001	0.98	1.10	-0.20	-0.27	1.61

Company vs Industry

	Last 5 Yrs Actual (%)	EPS Growth Rates 02/01 (%)	03/02 (%)	Nxt 5 Yrs (%)	P/E on 02 EPS
Company	-1.0	-25.2	48.1	4.3	19.7
Ind: (UTIL-GAS DISTR) (Ind Group #294)	5.0	-1.1	14.8	6.9	14.2
S&P 500	-1.1	30.2	13.2	8.0	18.4
Comp VS Ind	-6.0	888.0	33.3	-2.7	5.4
Comp VS S&P	888.0	-55.3	34.9	-3.8	1.3

Company Ratios: Current vs History

	Current	5-Year Avg
P/E (12 Mo)	19.9	15.8
Rel P/E	83%	
Net Margin	3%	4.4%
ROE	7.6%	9.7%
LT Debt/Cap	47%	43%

Company vs Industry Ratios

	LACLEDE GRP INC	INDUSTRY AVG	S&P 500
Pr Chg YTD	-1%		-19%
P/E (12Mo)	19.9	14.7	23.9
Price/Book	1.5	1.5	4.6
Price/Sales	0.6		
Price/CF	7.9	6.5	
Impl Ret/ P/E	0.50	0.76	
Div Yield	5.7%	4.7%	1.8%
Net Margin	3.1%	4.3%	
ROE	8%	12%	12%
Debt/Cap	47%		

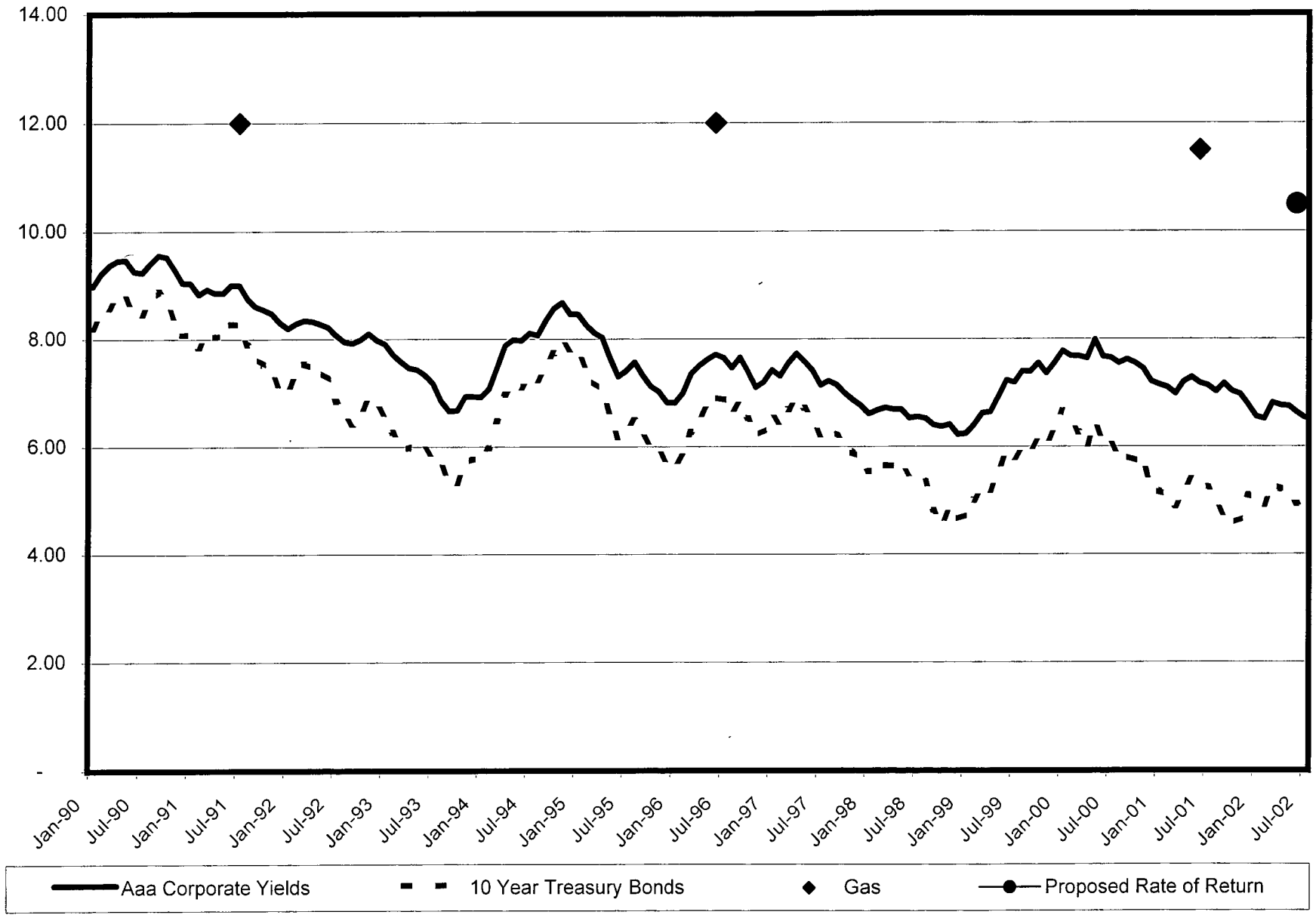
* Ranked 13/30 in UTIL-GAS DISTR. UTIL-GAS DISTR Ranked 179/211.

Zacks Company Report was last updated 08/19/02.

LACLEDE GRP INC
Annual Income Statement
(in millions except EPS data)

Fiscal Year End for LACLEDE GRP INC(LG) falls in the month of September.

Gas Equity Return Allowances and Contemporaneous Bond Yields



Source: Federal Reserve Board, http://www. federalreserve.gov, PUD Statistics

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
SUMMARY REPORT
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Operating Income and Rate of Return	Total North Dakota	Residential	Firm General	Air Force	Small Interruptible Sales	Small Interruptible Transport	Large Interruptible
Operating Revenues	95,413,765	52,578,009	34,740,173	4,935,516	1,946,488	625,072	588,507
Elimination of Unbilled Revenues	6,333,652	3,534,224	2,335,226	332,402	130,989	0	811
Adjustment to Operating Revenues	(34,111,944)	(17,742,221)	(12,641,390)	(2,759,326)	(670,672)	(61,663)	(236,672)
Adjusted Operating Revenues	67,635,473	38,370,012	24,434,009	2,508,592	1,406,805	563,409	352,646
Operating Expenses							
Cost of Gas	77,058,145	42,310,356	29,567,926	3,485,448	1,694,415	0	0
Adjustment to Cost of Gas	(28,065,930)	(15,412,151)	(10,769,989)	(1,267,554)	(616,236)	0	0
Other O&M Expense	12,722,671	8,171,782	3,950,475	116,449	111,627	155,925	216,413
Total Operation & Maint Exp.	61,714,886	35,069,987	22,748,412	2,334,343	1,189,806	155,925	216,413
Depreciation	3,059,362	1,604,902	1,182,853	54,607	42,150	68,900	105,950
Taxes Other Than Income Taxes	1,225,456	713,454	423,766	17,980	13,970	22,004	34,282
Fed & State Inc Taxes - Current	4,322,343	1,904,264	1,255,421	771,547	163,683	144,559	82,869
Tax Effect of Adjustments	100,673	421,454	162,339	(405,779)	26,794	(21,583)	(82,552)
Deferred Income Taxes	(4,031,688)	(2,120,656)	(1,499,911)	(278,083)	(134,012)	282	692
Total Operating Expenses	66,391,032	37,593,405	24,272,880	2,494,615	1,302,391	370,087	357,654
Operating Income	1,244,441	776,607	161,129	13,977	104,414	193,322	(5,008)
Rate Base	19,319,039	10,045,377	7,457,208	399,164	274,488	398,681	744,121
Rate of Return	6 442%	7.731%	2.161%	3.502%	38.040%	48.490%	-0 673%

Exhibit ___ (CWK-7
Page 1 of 5

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Cost of Service By Component	Total North Dakota	Residential			Firm General		
		Demand	Energy	Customer	Demand	Energy	Customer
Rate Base	19,319,039	2,642,618	2,060,043	5,342,716	1,804,409	1,467,581	4,185,218
Operating Income for Proposed Return	2,133,597	291,851	227,511	590,050	199,279	162,080	462,215
Current Operating Income	1,244,441	(613,202)	2,834,262	(1,444,453)	(418,703)	2,051,636	(1,471,804)
Increase in Operating Income	889,156	905,053	(2,606,751)	2,034,503	617,982	(1,889,556)	1,934,019
Related Taxes for Increase							
Federal Income	583,201	593,627	(1,709,777)	1,334,437	405,336	(1,239,366)	1,268,529
Total Increase in Revenue	1,472,357	1,498,680	(4,316,528)	3,368,940	1,023,318	(3,128,922)	3,202,548
Adjusted Revenue Before Increase	67,635,473	12,243,592	20,299,772	5,826,648	8,360,096	14,526,951	1,546,962
Total Cost of Service Required From Rates	69,107,830	13,742,272	15,983,244	9,195,588	9,383,414	11,398,029	4,749,510
Less Cost of Gas Items Recovered thru PGA	48,776,394	12,207,455	14,577,663	0	8,335,422	10,381,976	0
Net Distribution Costs	20,331,436	1,534,817	1,405,581	9,195,588	1,047,992	1,016,053	4,749,510
Billing Units at Customer							
Dk Throughput	35,875,902	7,681,994	7,681,994	0	5,470,992	5,470,992	0
Bills	993,588	0	0	859,416	0	0	132,276
Peak Day Dk Demand	200,723	114,254	0	0	78,014	0	0
Unit Cost of Service							
$ Per Dk		0 200	0 183	0 000	0.192	0.186	0.000
$ Per Customer Per Month		0 000	0 000	10 700	0.000	0 000	35.906

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Cost of Service By Component	Air Force			Small Interruptible Sales		
	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base	58,680	272,084	68,400	30,070	130,883	113,535
Operating Income for Proposed Return	6,481	30,049	7,554	3,321	14,455	12,539
Current Operating Income	(13,611)	42,960	(15,372)	(6,964)	147,969	(36,591)
Increase in Operating Income	20,092	(12,911)	22,926	10,285	(133,514)	49,130
Related Taxes for Increase						
Federal Income	13,178	(8,468)	15,037	6,746	(87,572)	32,225
Total Increase in Revenue	33,270	(21,379)	37,963	17,031	(221,086)	81,355
Adjusted Revenue Before Increase	271,903	2,226,002	10,687	142,108	1,233,379	31,318
Total Cost of Service Required From Rates	305,173	2,204,623	48,650	159,139	1,012,293	112,673
Less Cost of Gas Items Recovered thru PGA	271,101	1,931,807	0	141,695	929,275	0
Net Distribution Costs	34,072	272,816	48,650	17,444	83,018	112,673
Billing Units at Customer						
Dk Throughput	1,018,005	1,018,005	0	489,700	489,700	0
Bills	0	0	36	0	0	888
Peak Day Dk Demand	2,537	0	0	1,300	0	0
Unit Cost of Service						
$ Per Dk	0 033	0 268	0 000	0 036	0 170	0.000
$ Per Customer Per Month	0.000	0 000	1,351.389	0.000	0 000	126.884

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

	Small Interruptible Transport			Large Interruptible Sales		
Cost of Service By Component	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base	58,168	266,694	73,819	0	0	0
Operating Income for Proposed Return	6,424	29,454	8,153	0	0	0
Current Operating Income	(14,730)	218,685	(10,633)	0	(515)	(39)
Increase in Operating Income	21,154	(189,231)	18,786	0	515	39
Related Taxes for Increase						
Federal Income	13,875	(124,117)	12,322	0	338	26
Total Increase in Revenue	35,029	(313,348)	31,108	0	853	65
Adjusted Revenue Before Increase	782	487,917	74,710	0	0	0
Total Cost of Service Required From Rates	35,811	174,569	105,818	0	853	65
Less Cost of Gas Items Recovered thru PGA	0	0	0	0	0	0
Net Distribution Costs	35,811	174,569	105,818	0	853	65
Billing Units at Customer						
Dk Throughput	1,030,440	1,030,440	0	0	0	0
Bills	0	0	864	0	0	0
Peak Day Dk Demand	2,515	0	0	0	0	0
Unit Cost of Service						
$ Per Dk	0 035	0 169	0.000	0.000	0 000	0 000
$ Per Customer Per Month	0 000	0.000	122.475	0.000	0.000	0 000

Exhibit ___ (CWK-7
Page 4 of 5

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENET
PRO FORMA
TWELVE MONTHS ENDED DECEMBER 31, 2001

Cost of Service By Component	Large Interruptible Transport Demand	Energy	Customer
Rate Base	48,641	581,506	113,974
Operating Income for Proposed Return	5,372	64,222	12,587
Current Operating Income	(12,324)	9,318	(1,448)
Increase in Operating Income	17,696	54,904	14,035
Related Taxes for Increase			
Federal Income	11,607	36,012	9,206
Total Increase in Revenue	29,303	90,916	23,241
Adjusted Revenue Before Increase	654	296,580	55,412
Total Cost of Service Required From Rates	29,957	387,496	78,653
Less Cost of Gas Items Recovered thru PGA	0	0	0
Net Distribution Costs	29,957	387,496	78,653
Billing Units at Customer			
Dk Throughput	2,246,820	2,246,820	0
Bills	0	0	108
Peak Day Dk Demand	2,103	0	0
Unit Cost of Service			
$ Per Dk	0.013	0.172	0.000
$ Per Customer Per Month	0 000	0 000	728 269

Exhibit___(CWK-7)
Page 5 of 5

Montana-Dakota Utilities Company
Revenue-Neutral Customer Charges

Residential Rates	Rate 600	Rate 602	Rate 620	Rate 625	Combined	Rate 601	Rate 603	Rate 603 Gr Drying	Combined	Composite
Dk Consumption	6,036,094	1,569,880	124	10	7,606,108	55,349	1,913	989	58,251	
Commodity Revenue at Current Rates	$4,554,721	$1,404,680	$ 87	$ 10	$5,959,498	$ 33,321	$ 1,408	$ 680	$ 35,409	
Current Highest Block Rate					$ 0.561				$ 0.561	
Revenue Recovered at Highest Block Rate					$4,267,027				$ 32,679	
Excess Revenue Recovered in Lower Blocks					$1,692,471				$ 2,730	
Customer Billing Units	699,137	177,608	8	4	876,757	1,061	87	36	1,184	877,941
Added Customer Charge					$ 1.93				$ 2.31	
Current Customer Charge					$ 6.50				$ 13.00	
Proposed Customer Charge					$ 8.43				$ 15.31	$ 8.44

Firm General Rates	Rate 700	Rate 702	Combined	Composite	Rate 701	Rate 703	Combined	Composite
Dk Consumption	1,198,411	430,599	1,629,010		2,964,735	853,095	3,817,830	
Commodity Revenue at Current Rates	$ 979,317	$389,525	$1,368,842		$1,889,031	$623,005	$2,512,036	
Current Highest Block Rate			$ 0.579				$ 0.579	
Revenue Recovered at Highest Block Rate			$ 792,560				$1,454,469	
Excess Revenue Recovered in Lower Blocks			$ 576,282				$1,057,567	
Customer Billing Units	73,285	25,401	98,686		28,584	8,975	37,559	136,245
Added Customer Charge			$ 5.84				$ 28.16	
Current Customer Charge			$ 8.50				$ 17.00	
Proposed Customer Charge			$ 14.34				$ 45.16	$ 23

Source: MDU Response to Staff Data Request No. 1, Question 69

DA-399-02-183

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
William P Pearce
PO Box 400
Bismarck ND 58502-0400

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Bob Koch ☐ Agent ☐ Addressee

B. Received by (Printed Name) Bob Koch
C. Date of Delivery 9-4-0

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7099 3220 0002 8482 2950

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1035

DA-399-02-183

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Charles W King
Snavely King Majoros O'Connor & Lee
1220 L St NW Ste 410
Washington DC 20005

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Angel L Sinel ☐ Agent ☐ Addressee

B. Received by (Printed Name)
C. Date of Delivery 9-5-02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7099 3220 0002 8482 2967

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1035

PY- 399-02-183

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
MRL
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 8 30 02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7099 3220 0002 8482 2851

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

PY- 399-02-183

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Douglas Schulz
MRL
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 8-21-02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7099 3220 0002 8482 2943

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1035

ZUGER KIRMIS & SMITH

COUNSELORS AND ATTORNEYS AT LAW

Lyle W. Kirmis
Lance D. Schreiner, P.C.
James S. Hill, P.C. **^
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Rebecca S. Thiem, P.C.**
Daniel S. Kuntz, P.C.
Jerry W. Evenson, P.C.^
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Lawrence E. King, P.C.**
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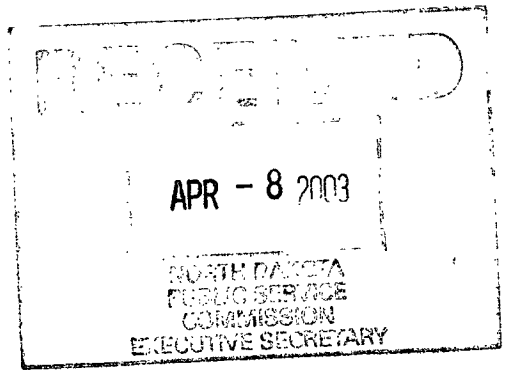
Minnesota **
Missouri+
Montana ++
South Dakota^^

^Certified Civil Trial Specialist
National Board of Trial Advocacy

April 8, 2003



Mr. Jon Mielke
Executive Secretary
ND Public Service Commission
600 East Boulevard Avenue -- 12th Floor
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co. Depreciation Investigation – PU-399-02-183

Dear Mr. Mielke:

Enclosed for filing are the original and seven copies of a Motion for Extension of Time. If you have any questions regarding this filing please contact me. Thank you for your cooperation in this matter.

Sincerely,

Daniel S. Kuntz

Enclosures

c: Bill Binek
Don Ball

138 PU-399-02-183 Pages: 1

Cover letter re Motion for Extension of Time
by Montana-Dakota Utilities Co., a Division of MDU Re

04/08/2003 CC: Comm Legal PUD (3) Mike ALJ

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

RECEIVED
APR - 8 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
SECRETARY

Montana-Dakota Utilities Co.)
Depreciation Investigation)

Case No. PU-399-02-183

MOTION FOR EXTENSION OF TIME

Montana-Dakota Utilities Co. moves the Public Service Commission for an extension of time to file rebuttal testimony and to reschedule the hearing date in this proceeding. Montana-Dakota Utilities Co. received the direct testimony of Charles W. King on behalf of the Public Service Commission staff on April 7, 2003. Montana-Dakota Utilities Co. requests an extension of time to April 28, 2003 to file its rebuttal testimony and further requests the Commission to reschedule the hearing that was previously set for April 22, 2003. Montana-Dakota Utilities Co. has conferred with counsel for the Public Service Commission Staff regarding this request and counsel has stated the Staff does not object to this motion.

Dated this 8th day of April, 2003.

Respectfully submitted,

By: _____

Daniel S. Kuntz (ID #03490)
Zuger Kirmis & Smith
Attorneys for Montana-Dakota Utilities Co.
P.O. Box 1695
Bismarck, ND 58502-1695
(701)223-2711

137 PU-399-02-183 Pages: 1
Motion for Extension of Time
by Montana-Dakota Utilities Co., a Division of MDU R
04/08/2003 CC: Comm Legal PUD (3) Mike ALJ

Affidavit of Publication

RECEIVED
MAR 27 2003
PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

State of North Dakota)
)
County of Burleigh)

Laurie Thiel, being duly sworn, state as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of:
MDU, 1 time(s)
as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Laurie Thiel

Subscribed and sworn to before me this 25th day of March A.D. 2003

Kelli Richey

KELLI RICHEY
Notary Public
State of North Dakota
My Commission Expires Oct. 13, 2006

136 PU-399-02-183 Pages: 1

Affidavit of Publication

by North Dakota Advertising Service, Inc.

03/27/2003 CC: Comm Legal PUD (3) Mike ALJ

North Dakota Newspaper Association
1435 Interstate Loop
Bismarck, ND 58503-0567
Ph (701) 223-6397 • Fax (701) 223-8185

INVOICE

Order **17348-03033PP2** Invoice # **14383**

March 26, 2003

Advertiser: **Public Service Commission**

P.O.#:

Amount Due	**$316.21**
Amount Paid	

Attn: JONH. MIELKE
PUBLIC SERVICE COMMISSION
600 E. BOULEVARD AVE.
STATE CAPITOL
BISMARCK, ND 58505

Voice: 328-4076

Please detach and return this portion with your payment

Public Service Commission Invoice # 17348-03033PP2-14383

Ad Size	*Rate Type*	*Rate*	*Total*	*Discount (%)*	*Caption*	*Page*	*Run Date*
Bismarck Tribune (Bismarck ND)							
61.00	SPR2	0.64	39.04	0.00	MDU		03/19/03
Devils Lake Daily Journal (Devils Lake ND)							
63.00	SPR2	0.63	39.69	0.00	MDU		03/19/03
Dickinson Press (Dickinson ND)							
67.00	SPR2	0.57	38.19	0.00	MDU		03/19/03
Grand Forks Herald (Grand Forks ND)							
61.00	SPR2	0.69	42.09	0.00	MDU		03/18/03
Jamestown Sun (Jamestown ND)							
71.00	SPR2	0.54	38.34	0.00	MDU		03/19/03
Minot Daily News (Minot ND)							
71.00	SPR2	0.54	38.34	0.00	MDU		03/19/03
Valley City Times-Record (Valley City ND)							
70.00	SPR3	0.61	42.70	0.00	MDU		03/19/03
Williston Herald (Williston ND)							
62.00	SPR2	0.61	37.82	0.00	MDU		03/19/03

MAR 27

Gross Advertising	316.21	Total Misc	0.00	Amount Paid	0.00
Agency Discount		Tax	0.00	Adjustments	0.00
Other Discount	0.00	Total Billed	316.21	Payment Date	
Service Charge	0.00	Unbilled	0.00	Balance Due	316.21

136 **PU-399-02-183** Pages: 1

Affidavit of Publication

by North Dakota Advertising Service, Inc.

03/27/2003 CC: Comm Legal PUD (3) Mike ALJ

Notice Of Hearing And Procedural Schedule
March 12, 2003
Case No. PU-399-02-183

Bismarck	3-19
Devils Lake	3-19
Dickinson	3-19
Fargo	
Grand Forks	3-18
Jamestown	3-19
Minot	3-19
Valley City	3-19
Wahpeton	3-19
Williston	3-19

APPROVED
DATE: 3-26-03
KMF

MOTION

March 26, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the commission extend the final day for completion and service upon MDU and other parties of prepared testimony and exhibits from April 1, 2003, to April 8, 2003, in Case No. PU-399-02-183.

mrd

135 PU-399-02-183 Pages. 1

Motion to extend filing deadline

by Public Service Commission

03/26/2003 CC: Comm Legal PUD (3) Mike ALJ

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

RECEIVED
MAR 24 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

March 24, 2003

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Case No. PU-399-02-183
Depreciation Investigation

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., states that it does not object to extending the final day for completion and service upon MDU and other parties of prepared testimony and exhibits from April 1, 2003, to April 8, 2003. Depending on the nature of such testimony, Montana-Dakota may need more than one week after April 8 for its rebuttal testimony. If so, Montana-Dakota will make such a request at the appropriate time.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,

Donald R. Ball

Donald R. Ball
Assistant Vice President –
Regulatory Affairs

Attachments
c: D. Schulz

134 PU-399-02-183 Pages: 1

No objection to extending the final day for
filing testimony
by Montana-Dakota Utilities Co., a Division of MDU R

03/24/2003 CC: Comm Legal PUD (3) Mike ALJ

Public Service Commission
Receipt of Payment

Receipt# 5307

Received: 3/20/2003 Check# 973457 for $4,094.45

Subject: Utility Valuation

Docket # PU-399-02-183

Montana-Dakota Utilities Co., a Division of MDU Resources
400 N 4th Street
Bismarck ND 58501

133 PU-399-02-183 Pages: 1

Receipt# 5,307 $4,094.45

by Montana-Dakota Utilities Co., a Division of MDU Re

03/20/2003

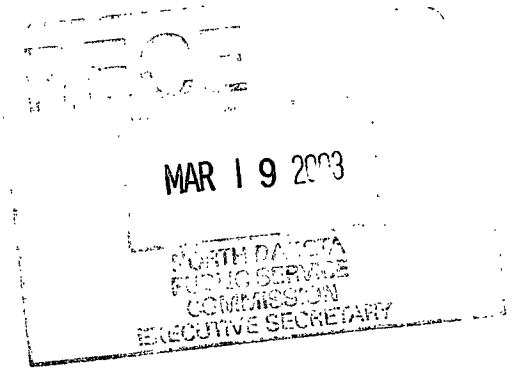
OFFICE OF ADMINISTRATIVE HEARINGS

STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state.nd.us
www.state.nd.us/oah

March 18, 2003



Mr. William W. Binek
Hearing Administrator
Public Service Commission
600 E. Boulevard Avenue - Dept. 408
Bismarck, ND 58505

Dear Mr. Binek:

Thank you for your March 14, 2003, request of the designation of an administrative law judge from the Office of Administrative Hearings to conduct a hearing in the matter of Montana-Dakota Utilities Co. (PU-399-02-183). I hereby designate myself to be assigned as an administrative law judge to conduct the hearing in regard to this matter. Because the administrative law judge will not be making recommended findings of fact and conclusions of law, or issuing a recommended order, the person or persons who will actually be making the final administrative decision in regard to this matter (i.e., commission) must actually be in attendance at the hearing.

Please send all additional relevant documents in regard to this matter (correspondence, and other pleadings and documents) to the designated administrative law judge in care of the Office of Administrative Hearings, 1707 North 9th Street, Bismarck, North Dakota 58501-1882. I understand the hearing has been scheduled for April 22, 2003, beginning at 9:00 a.m., in the Commission's Hearing Room, 12th Floor, State Capitol, 600 E. Boulevard Avenue, Bismarck, North Dakota.

Sincerely,

Allen C. Hoberg
Director

ACH:ljc

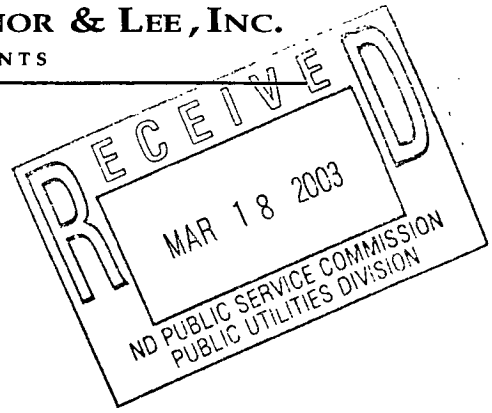
cc: Mr. Daniel S. Kuntz

132 PU-399-02-183 Pages: 1

Allen Hoberg appointed as ALJ for
4/22/03 hearing
by Office of Administrative Hearings

03/19/2003 CC: Comm Legal PUD (3) Mike ALJ

SNAVELY KING MAJOROS O'CONNOR & LEE, INC.
ECONOMIC AND MANAGEMENT CONSULTANTS



March 10, 2003

Patrick Fahn
Public Service Commission of North Dakota
12th Floor
State Capitol, 400 E. Boulevard Ave, Dept 408
Bismarck, ND 58505-0480

Dear Mr. Fahn

Enclosed is the signed copy of our the extension of our contract covering Case No. PU—399-02-183. This extension covers the deferred depreciation phase of the proceeding.

Thank you for you attention to this matter.

Sincerely,

Charles W. King

131 **PU-399-02-183** Pages: 1

Cover letter re signed contract

by Snavely King Majoros O'Connor & Lee, Inc.

03/18/2003 CC: Comm Legal PUD (3) Mike ALJ

1220 L STREET, NW, SUITE 410, WASHINGTON, DC 20005-(202)371-1111, FAX (202)842-4966

1471 CASTILLO DELMAR, CAROLINA, PR 00979-(809)783-7683, FAX(809)783-7559

FIRST AMENDED CONTRACT

Administrator: Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505-0480
(701) 328-2400

Date: March 4, 2003

Susan E. Wefald	Tony Clark	Leo M. Reinbold
Commissioner	**President**	**Commissioner**

Contractor

Snavely King Majoros O'Connor & Lee, Inc.
Name

1220 L St NW Ste 410	Washington D C 20005	202-371-9156
Address	**City/State/Zip**	**Phone**

Charles W. King	President
Typed Name	**Title**
Signature	**Date** March 10, 200

Agreement Information

Contract No.: PU-445-02

Start Date: 03-12-03

End Date: 6-30-03

Program Title: PU-399-02-183

Type of Contract: ( ) Fixed Price
(X) Cost Reimb. ( ) Unit Price
( ) Other

Budget Information

Cost Center: 7700

Services: Existing contract ($48,534) plus $9,500.25 equals $58,034.25

Optional on-site review: 0

Expenses: 0

ID 52-0901220

Type of Contractor: ( ) Individual
(X) Corporation ( ) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other

This contract is entered into between the above two parties. This contract consists of this sheet, general provisions and specific provisions.

GENERAL PROVISIONS

CONTRACTUAL FEATURES

Legal Authority

The Contractor assures that it possesses legal authority to participate in this contract.

Assignment/Subcontracting

The Contractor may not assign this contract or any part thereof, or assign any of the monies to be paid hereunder, nor shall any part of the work done or material furnished under this contract be sublet.

The Contractor may not enter into subcontracts for any of the work contemplated under this contract unless included in the specific provisions of this contract.

Termination

The Commission, by ten days written notice listing causes and reasons, may terminate this contract in whole or in part when it is determined that the Contractor has failed to meet the conditions of the contract. The Commission will be liable only for payment provisions of this contract for services satisfactorily rendered prior to the effective date of termination.

Significant deviation from performance standards in this contract may result in reduced or terminated financial participation of the Contractor, subsequent to negotiations with the Commission.

The Contractor or the Commission may terminate this contract in whole or in part upon settlement or when both parties agree that the continuation of the contract would not produce results commensurate with further expenditures of funds. The two parties shall agree upon the termination conditions including effective date and in the case of partial terminations, that portion to be terminated.

In the event state or federal funds are reduced or terminated, the financial participation of the Commission may be reduced or terminated.

Disputes

The Contractor agrees to attempt to resolve disputes arising from this contract by administrative process and negotiations in lieu of litigation. Continued performance by the Contractor during disputes is assured.

Any dispute concerning a question of fact arising under this contract which is not settled by the informal means shall be decided by the authorized representative of the Commission who shall reduce the decision to writing and mail or otherwise furnish a copy thereof to the Contractor.

The Contractor shall be afforded an opportunity to be heard and to offer evidence in support of an appeal. Pending final decision of a dispute, the Contractor shall proceed diligently with the performance of the contract and in accordance with the decision of the Commission.

FISCAL RESPONSIBILITIES

Records

The Contractor agrees to maintain program records required by the Commission and to produce program narrative and statistical data at times prescribed by the Commission.

The Contractor agrees to maintain and retain all books, records, and other documents required by the Commission relevant to this agreement for four years after final payment. Records shall be retained beyond four years if audit findings have not been resolved.

No Claim for Additional Work

No claim for additional services not specifically herein provided, done, or furnished by the Contractor will be allowed, nor shall the Contractor do any work or furnish any material not covered by the contract, unless such work is ordered in writing by the Commission.

Time Keeping Procedures

The Contractor shall require employees and subcontractors, if applicable, whose positions are funded under this contract or included as match, to maintain adequate documentation for services provided. For positions that are funded from more than one source, an analysis of duties performed by program shall also be prepared.

Monitoring, Evaluation and Audit

The Contractor agrees to cooperate with any monitoring, evaluating and/or audit conducted by the Commission, or their designees who shall have full access to and the right to examine all books, records and other relevant documents.

The Contractor agrees to take immediate corrective action on deficiencies disclosed through program monitoring of costs disallowed in the course of an audit, review, or monitoring.

PROGRAM REQUIREMENTS

Equal Opportunity

No individual shall be excluded from participation in, denied the benefits of, subjected to discrimination under, or denied employment in the administration of or in connection with this contract because of race, color, disability, or political affiliation or belief.

The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship.

Nondiscrimination

This contract and any subcontract hereunder is subject to the Age Discrimination Act of 1975, Section 504 of the Rehabilitation Act, Title VI of the Civil Rights of 1964 and the Americans with Disabilities Act of 1990.

Copyrights and Rights in Data

The contractor agrees that any plans, drawings, designs, specifications, computer programs (which are substantially paid for with federal grant or state funds), technical reports, operation manuals and other work submitted with a proposal or grant application or which are specified to be delivered under this contract or which are developed or produced and paid for under this contract (referred to in this clause as "subject data") are subject to the rights of the Commission to use, duplicate and disclose the subject data in whole or in part, in any manner for any purpose whatsoever, and have others do so. If the material is copyrightable, the contractor may copyright the material, subject to the rights in the government, but the Commission reserves a royalty-free, non-exclusive and irrevocable license to reproduce, publish and use the material, in whole or in part, and to authorize others to do so. The contractor shall include provisions appropriate to effectuate the purposes of this condition in all subcontracts expected to produce copyrightable "subject data."

SPECIFIC PROVISIONS
March 12, 2003

Purpose

In its Order of December 10, 2002 concerning the rate increase application of Montana-Dakota Utilities Co. ("MDU"), Case No. PU 399-02-183, the Commission deferred its consideration of depreciation pending the filing of a new depreciation study by MDU. MDU has since filed its depreciation study, and staff requires assistance to analyze that study and to provide written and oral testimony. The contractor will determine the appropriate depreciation rates for each of MDU depreciable gas and general plant accounts. The work will include sufficient detail as is necessary to successfully testify under cross-examination. The contractor will also address the relevance and effect of Statement of Financial Accounting Standards No. 143 to MDU's treatment of retirement costs.

All work under this contract must be completed prior to the commission's fiscal year ending June 30, 2003. More importantly, the work needs to be sufficiently complete so as to provide written testimony by April 1, 2002 and oral testimony at the technical hearing to be held April 22-25, 2003.

The specific purpose is to investigate, analyze and provide testimony proposing the proper depreciation rates for MDUs depreciable gas and general plant accounts, including:

1. Professional analysis and review of MDU's depreciation study.
2. Prepare and conduct discovery.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff updated.
4. Prepare written testimony and provide an advanced copy to staff for review prior to submitting as a formal document.
5. Prepare written and oral testimony in rebuttal to testimony of other parties in the proceeding.
6. Testify at the hearing.
7. Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings.
8. After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed Commission decision.

Compensation

The Contractor will be compensated based on periodic submittal of progress reports. Final payment will be made upon satisfactory completion of the described project work, as determined by the Commission.

In the event the case is settled or this agreement is otherwise terminated prior to completion of project work, then compensation will be awarded for work satisfactorily completed.

No part of this contract may be assigned, sublet or subcontracted.

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

March 17, 2003

Mr. Allen C. Hoberg
Office of Administrative Hearings
1707 North 9th Street, Lower Level
Bismarck, ND 58501

Re: Continued Hearing
Case No. PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Dear Mr. Hoberg:

Enclosed is a request for an administrative law judge in the above case. The Commission issued an order in this proceeding on December 18, 2002. The Commission agreed that Montana-Dakota Utilities Company submit a depreciation study for review as a continued issue in this proceeding.

The Commission has scheduled a hearing for April 22, 2003, beginning at 9 a.m. (CST) in the Commission's Hearing Room, 12th Floor, State Capitol, Bismarck. The administrative law judge will serve as a procedural law judge, a court reporter will be present, and the hearing will be tape recorded. A copy of the depreciation study is enclosed.

Please provide the Commission with a copy of any filings issued by your office in this matter.

If you have any questions, please contact me. Thank you.

Sincerely,

William W. Binek
Hearing Administrator

/sls
Enclosure

c: Daniel S. Kuntz, Attorney (Letter only)
Douglas Schultz, Attorney (Letter only)
Don Ball, MDU (Letter only)

129 PU-399-02-183 Pages: 1

Letter to ALJ re request

by Public Service Commission

03/17/2003C. Comm Legal PUD (3) Mike AG's Office

REQUEST FOR ADMINISTRATIVE LAW JUDGE--APPEAL, APPLICATION, OR PETITION

NORTH DAKOTA OFFICE OF ADMINISTRATIVE HEARINGS

SFN 17819 (Rev. 03-2001)

Name of Agency, Board, or Commission
Public Service Commision

The above named agency, board, or commission requests designation of an administrative law judge from the Office of Administrative Hearings for the Continued Hearing, Case No. PU-399-02-183, Montana-Dakota Utilities Co., Natural Gas Rate Increase Application.

(e.g., application of [name], appeal of [name], petition of [name]). Authority for the administrative action is found in Title 49 (North Dakota Century Code and/or North Dakota Administrative Code).

Please attach related documents and correspondence.

The administrative action is more fully described as follows:
Commission issued an order in this proceeding 12/18/02. MDU has submitted a depreciation study as a continued issue in this proceeding.

It requests designation of an administrative law judge (please check one):

- ☐ **To conduct the hearing and issue recommended findings of fact, conclusions of law, and order.**
- ☑ **To serve as a procedural administrative law judge only (no recommended decision). The agency head will be present at the hearing as required by NDCC 54-57-04(6).**
- ☐ **To conduct the hearing, issue findings of fact, conclusions of law, and a final order.**

PLEASE MAKE A REQUEST FOR AN ADMINISTRATIVE LAW JUDGE AT LEAST ONE MONTH BEFORE THE HEARING.

Please list parties, including the agency if it is a Party, and Representation [attorney (or other)] if known, or Agency Contact: (Attach separate list if necessary.)

AGENCY Public Service Commission	Address 600 E Blvd. Ave. Dept. 408, Bismarck, ND	Telephone Number 328-2400
Representation William W. Binek	Address Same as Above	Telephone Number 328-4088
PARTY Montana-Dakota Utilities Co.	Address 400 N 4th Street, Bismarck, ND 58501	Telephone Number 222-7900
Representation Douglas Schulz, Counsel & Don Ball	Address 400 N 4th Street, Bismarck, ND 58501	Telephone Number 222-7900
PARTY MDU	Address Same	Telephone Number
Representation Daniel S. Kuntz, Attorney	Address P. O. Box 1695, Bismarck, ND 58502-1695	Telephone Number 223-2711

Additional Comments
The hearing will be tape recorded and a court reporter will be present.

(For agencies required to use OAH, notice of hearing will be issued by the administrative law judge, unless a procedural administrative law judge is requested. Other requesting agencies and agencies requesting a procedural administrative law judge should first contact OAH about scheduling a hearing. If notice has already been issued, attach a copy of the notice.)

Typed or Printed Name and Title of Requesting Person	Date
William W. Binek, Hearing Administrator	3-14-03
Signature of Requesting Person X	Telephone Number 328-4081

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **13th day of March, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Notice of Hearing and Procedural Schedule

The envelope was addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2510 0001 2975 2631

William Pearce
P O Box 400
Bismarck ND 5[illegible]
Cert. No. 7001 [illegible]

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2510 0001 2975 2655

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **13th day of March, 2003**.

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

Sandra L Scott
Notary Public

127 PU-399-02-183 Pages: 5

Affidavits of Service

by Public Service Commission

03/13/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **13th day of March, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Notice of Hearing and Procedural Schedule

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **13th day of March, 2003**.

Sandra L. Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

akemp@tminc.com
Ann-Marie Kemp

ccano@mh.com
Craig Cano
Gas Utility Report
1200 G St NW Ste 1100
Washington DC 20005

Mark.Hanson@grandforks.af.mil
Mark Hanson
Grand Forks Air Force Base
319 ARW/JA
460 Steen Blvd Ste 201
Grand Forks ND 58205

inland@btigate.com
Inland Oil & Gas Corp
PO Box 1313
Bismarck ND 58502-1313

jason_gustafson@bobcat.com
Jason Gustafson
Melroe Company
P O Box 128
Gwinner ND 58040-0128

craig_scott@bobcat.com
Craig Scott
Melroe Company
P O Box 128
Gwinner ND 58040-0128

tom.hopgood@mduresources.com
Tom Hopgood
Montana-Dakota Utilities Co

balld@mdu.mdures.com
Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

collinsk@mdu.mdures.com
Karen Collins
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

wpp@pearce-durick.com
William Pearce
Pearce & Durick Attorneys
PO Box 400
Bismarck ND 58502-0400

mdickers@state.nd.us
Marcy Dickerson
State Tax Department
State Capitol
Bismarck ND 58505

dave.sederquist@xcelenergy.com
Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58108-2747

F James Moriarty
2333 Plum Grove Dr
O'Fallon MO 63366

Steven Tomac
2498 59th St
St Anthony ND 58566-9640

Will Kaul
Cooperative Power Association
P O Box 800
Elk River MN 55330-0800

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Frank Morehouse
Great Plains Natural Gas Co
PO Box 176
Fergus Falls MN 56548-0176

Jay Casler
INDEPTH DATA INC
44 S Bdwy 18th Fl
White Plains NY 10601-4425

Karyn Grass
IPAMS
6620 Denver Club Bldg 518 17th St
Denver CO 80202-4167

KBMR AM-KQDY FM
3500 E Rosser Ave
Bismarck ND 58501

KBMW-AM
PO Box 1115
Wahpeton ND 58074-1115

KDAK AM
Box 50
Carrington ND 58421-0050

Rod Kleinjan
KDIX AM Radio
119 2nd Ave W
Dickinson ND 58601-5115

KDLR AM-FM
Box 190
Devils Lake ND 58301-0190

KEYZ-AM
PO Box 2048
Williston ND 58802-2048

Jeff Alexander
KFYR-AM Radio
PO Box 1738
Bismarck ND 58502-1738

KHRT AM
PO Box 1210
Minot ND 58702-1210

KMOT TV
Box 1120
Minot ND 58702-1120

KNDK-AM
HCR 5 Box 9
Langdon ND 58249

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

KOVC-AM
PO Box 994
Valley City ND 58072-0994

KSJB AM and KSJZ FM Radio
PO Box 5180
Jamestown ND 58402-5180

KTGO-AM
Box 457
Tioga ND 58852-0457

KUMV-TV
PO Box 1287
Williston ND 58802-1287

News Director
KXMA-TV
Drawer B
Dickinson ND 58602

KXMB TV
Box 1617
Bismarck ND 58502-1617

KXMC TV
Box 1686
Minot ND 58701-1686

KXMD-TV
PO Box 790
Williston ND 58802-0790

KXPO AM & FM Radio
856 W 12 St
Grafton ND 58237

C W Fox
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Ron Tipton
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Scott Speaker
Natural Gas Week
1401 New York Ave NW Ste 500
Washington DC 20005-2150

Harlan Fuglesten
ND Association of RECs
PO Box 727
Mandan ND 58554-0727

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Helbling, Sharon D.

From: Helbling, Sharon D.
Sent: Thursday, March 13, 2003 7:49 AM
To: ndna (E-mail)
Subject: Attached Notice of Hearing and Procedural Schedule, Case No. PU-399-02-183

Colleen Park
North Dakota Newspaper Association

Colleen:

Please have the attached Notice of Hearign and Procedural Schedule published as a legal publication and run it as a "News Item Only" article in the next issue of the following newspapers:

Bismarck Tribune
The Dickinson Press
Minot Daily News
Williston Daily Herald
Devils Lake Journal
Jamestown Sun
Valley City Times-Record
Grand Forks Herald

Please send the bill to the Public Service Commission along with a tear sheet for billing purposes.

If you have any questions, please call me at 328-4076.

Thank you.

Sharon Helbling
Public Utilities Division

126 PU-399-02-183 Pages: 1

Notice e-mailed to NDNA requesting publication
by Public Service Commission

03/13/2003 CC: Comm Legal Illona, Pat, Jerry Mike

APPROVED
DATE: 3-12-03
KMF

MOTION

March 12, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission issue a Notice of Hearing in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application in Case No. PU-399-02-183.

sdh

125 PU-399-02-183 Pages. 1

Motion to issue Notice of Hearing

by Public Service Commission

03/12/2003 CC: Comm Legal Illona, Pat, Jerry Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

NOTICE OF HEARING and PROCEDURAL SCHEDULE

March 12, 2003

On December 18, 2002, the Public Service Commission issued an order in this proceeding. The Commission agreed that Montana-Dakota Utilities Company (MDU) submit a depreciation study for review by January 31, 2003 as a continued issue in this proceeding, subject to the standard and customary contested case process with all parties having rights of discovery, testimony, rebuttal testimony, hearing and briefing. MDU's depreciation study was to include gas and common plant facilities. Any resulting change in depreciation expense ordered by the Commission at the conclusion of the review will be reflected in rates on a prospective basis.

On January 31, 2003, MDU filed its depreciation study.

The issues in this proceeding are:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is the appropriate treatment of plant retirement costs?
3. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

A hearing in this proceeding will be held beginning **April 22, 2003, at 9 a.m. CDT, in the Commission Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota**. The hearing is open to the public, but participation is limited to the parties named herein and Commission staff.

The final day for completion and service upon MDU and other parties of prepared testimony and exhibits is April 1, 2003. The final day for service of rebuttal testimony is April 14, 2003.

For more information, contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400; or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or braille materials please notify Jon Mielke, Executive Secretary.

PUBLIC SERVICE COMMISSION

Susan E. Wefald **Commissioner**	**Tony Clark** **President**	**Leo M. Reinbold** **Commissioner**

APPROVED
DATE: 3-12-03
KMF

MOTION

March 12, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission bill Montana-Dakota Utilities Co. for costs incurred to date in Case No. PU-399-02-183, Montana-Dakota Utilities Co., Natural Gas Rate Increase, Application.

123 PU-399-02-183 Pages: 3

Utility Valuation Motion/Letter/Billing Statement
by Public Service Commission

03/12/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Leo M. Reinbold
Susan E. Wefald

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

March 12, 2003

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

RE: Case No. PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the March 12, 2003 Public Service Commission meeting for the expenses incurred to date in Case No. PU-399-02-183.

Under N.D.C.C. 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Administrative Staff Officer
701-328-2401

Enc.

Billing Statement

March 12, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

Expenses Incurred to Date:

Consulting Services	$4,094.45

Amount Due:

Montana-Dakota Utilities Co.	$4,094.45

Send Payment and a Copy of this Statement To:

Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

Public Service Commission
State of North Dakota

COMMISSIONERS

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e-mail: sab@psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

March 4, 2003

Charles W King
Snavely King Majoros O'Connor & Lee Inc
1220 L St NW Ste 410
Washington D C 20005

Dear Mr. King:

Enclosed is First Amended Contract No. PU-445-02 for consulting services in Case No. PU-399-02-183. Please sign both copies of the contract, keep one copy for your files and return one copy to me.

When submitting invoices for payment, **please send them directly to me** and identify the case number for each invoiced amount.

If you have any questions, please call me at 701-328-4079.

Sincerely,

Patrick J Fahn
Public Utility Analyst

Enclosures

122 **PU-399-02-183** Pages: 1

Letter to consultant re first amended contract
by Public Service Commission

03/04/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

APPROVED

MOTION DATE: 3-4-03 KMF

March 4, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission execute a First Amended Contract for an additional $9,500.25 with Snavely King Majoros O'Connor & Lee, Inc. for consulting services in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase Application, Case No. PU-399-02-183.

PJF

121 **PU-399-02-183** Pages: 1

Motion to execute 1st Amended Contract for $9,500.25 w/Snavely King Majoros etc. by Public Service Commission

03/04/2003 CC: Comm Legal Illona, Pat. Jerry Mike .

FIRST AMENDED CONTRACT

Administrator:	Public Service Commission State Capitol - 12th Floor Bismarck, ND 58505-0480 (701) 328-2400
Date: March 4, 2003	

Susan E. Wefald	Tony Clark	Leo M. Reinbold
Commissioner	**President**	**Commissioner**

Contractor

Snavely King Majoros O'Connor & Lee, Inc.
Name

1220 L St NW Ste 410	Washington D C 20005	202-371-9156
Address	**City/State/Zip**	**Phone**

Charles W. King	President
Typed Name	**Title**

Signature **Date**

Agreement Information

Contract No.: PU-445-02

Start Date: 03-12-03

End Date: 6-30-03

Program Title: PU-399-02-183

Type of Contract: ( ) Fixed Price
(X) Cost Reimb. ( ) Unit Price
( ) Other

Budget Information

Cost Center: 7700

Services: Existing contract ($48,534) plus $9,500.25 equals $58,034.25

Optional on-site review: 0

Expenses: 0

ID 52-0901220

Type of Contractor: ( ) Individual
(X) Corporation ( ) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other

This contract is entered into between the above two pa
general provisions and specific provisions.

GENERAL PROVISIONS

CONTRACTUAL FEATURES

Legal Authority

The Contractor assures that it possesses legal authority to participate in this contract.

Assignment/Subcontracting

The Contractor may not assign this contract or any part thereof, or assign any of the monies to be paid hereunder, nor shall any part of the work done or material furnished under this contract be sublet.

The Contractor may not enter into subcontracts for any of the work contemplated under this contract unless included in the specific provisions of this contract.

Termination

The Commission, by ten days written notice listing causes and reasons, may terminate this contract in whole or in part when it is determined that the Contractor has failed to meet the conditions of the contract. The Commission will be liable only for payment provisions of this contract for services satisfactorily rendered prior to the effective date of termination.

Significant deviation from performance standards in this contract may result in reduced or terminated financial participation of the Contractor, subsequent to negotiations with the Commission.

The Contractor or the Commission may terminate this contract in whole or in part upon settlement or when both parties agree that the continuation of the contract would not produce results commensurate with further expenditures of funds. The two parties shall agree upon the termination conditions including effective date and in the case of partial terminations, that portion to be terminated.

In the event state or federal funds are reduced or terminated, the financial participation of the Commission may be reduced or terminated.

Disputes

The Contractor agrees to attempt to resolve disputes arising from this contract by administrative process and negotiations in lieu of litigation. Continued performance by the Contractor during disputes is assured.

Any dispute concerning a question of fact arising under this contract which is not settled by the informal means shall be decided by the authorized representative of the Commission who shall reduce the decision to writing and mail or otherwise furnish a copy thereof to the Contractor.

The Contractor shall be afforded an opportunity to be heard and to offer evidence in support of an appeal. Pending final decision of a dispute, the Contractor shall proceed diligently with the performance of the contract and in accordance with the decision of the Commission.

FISCAL RESPONSIBILITIES

Records

The Contractor agrees to maintain program records required by the Commission and to produce program narrative and statistical data at times prescribed by the Commission.

The Contractor agrees to maintain and retain all books, records, and other documents required by the Commission relevant to this agreement for four years after final payment. Records shall be retained beyond four years if audit findings have not been resolved.

No Claim for Additional Work

No claim for additional services not specifically herein provided, done, or furnished by the Contractor will be allowed, nor shall the Contractor do any work or furnish any material not covered by the contract, unless such work is ordered in writing by the Commission.

Time Keeping Procedures

The Contractor shall require employees and subcontractors, if applicable, whose positions are funded under this contract or included as match, to maintain adequate documentation for services provided. For positions that are funded from more than one source, an analysis of duties performed by program shall also be prepared.

Monitoring, Evaluation and Audit

The Contractor agrees to cooperate with any monitoring, evaluating and/or audit conducted by the Commission, or their designees who shall have full access to and the right to examine all books, records and other relevant documents.

The Contractor agrees to take immediate corrective action on deficiencies disclosed through program monitoring of costs disallowed in the course of an audit, review, or monitoring.

PROGRAM REQUIREMENTS

Equal Opportunity

No individual shall be excluded from participation in, denied the benefits of, subjected to discrimination under, or denied employment in the administration of or in connection with this contract because of race, color, disability, or political affiliation or belief.

The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship.

Nondiscrimination

This contract and any subcontract hereunder is subject to the Age Discrimination Act of 1975, Section 504 of the Rehabilitation Act, Title VI of the Civil Rights of 1964 and the Americans with Disabilities Act of 1990.

Copyrights and Rights in Data

The contractor agrees that any plans, drawings, designs, specifications, computer programs (which are substantially paid for with federal grant or state funds), technical reports, operation manuals and other work submitted with a proposal or grant application or which are specified to be delivered under this contract or which are developed or produced and paid for under this contract (referred to in this clause as "subject data") are subject to the rights of the Commission to use, duplicate and disclose the subject data in whole or in part, in any manner for any purpose whatsoever, and have others do so. If the material is copyrightable, the contractor may copyright the material, subject to the rights in the government, but the Commission reserves a royalty-free, non-exclusive and irrevocable license to reproduce, publish and use the material, in whole or in part, and to authorize others to do so. The contractor shall include provisions appropriate to effectuate the purposes of this condition in all subcontracts expected to produce copyrightable "subject data."

SPECIFIC PROVISIONS
March 12, 2003

Purpose

In its Order of December 10, 2002 concerning the rate increase application of Montana-Dakota Utilities Co. ("MDU"), Case No. PU 399-02-183, the Commission deferred its consideration of depreciation pending the filing of a new depreciation study by MDU. MDU has since filed its depreciation study, and staff requires assistance to analyze that study and to provide written and oral testimony. The contractor will determine the appropriate depreciation rates for each of MDU depreciable gas and general plant accounts. The work will include sufficient detail as is necessary to successfully testify under cross-examination. The contractor will also address the relevance and effect of Statement of Financial Accounting Standards No. 143 to MDU's treatment of retirement costs.

All work under this contract must be completed prior to the commission's fiscal year ending June 30, 2003. More importantly, the work needs to be sufficiently complete so as to provide written testimony by April 1, 2002 and oral testimony at the technical hearing to be held April 22-25, 2003.

The specific purpose is to investigate, analyze and provide testimony proposing the proper depreciation rates for MDUs depreciable gas and general plant accounts, including:

1. Professional analysis and review of MDU's depreciation study.
2. Prepare and conduct discovery.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff updated.
4. Prepare written testimony and provide an advanced copy to staff for review prior to submitting as a formal document.
5. Prepare written and oral testimony in rebuttal to testimony of other parties in the proceeding.
6. Testify at the hearing.
7. Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings.
8. After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed Commission decision.

Compensation

The Contractor will be compensated based on periodic submittal of progress reports. Final payment will be made upon satisfactory completion of the described project work, as determined by the Commission.

In the event the case is settled or this agreement is otherwise terminated prior to completion of project work, then compensation will be awarded for work satisfactorily completed.

No part of this contract may be assigned, sublet or subcontracted.

APPROVED

DATE: 2-27-03
KMF

MOTION

February 27, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the commission authorize sole source procurement with Snavely King Majaros O'Connor & Lee, Inc. for the purpose of conducting an analysis of the gas utility depreciation study filed by Montana-Dakota Utilities Co. in Case No. PU-399-02-183.

pjf

119 PU-399-02-183 Pages: 1

Motion for sole source procurement
w/Snavely King etc
by Public Service Commission

02/27/2003 CC: Comm Legal Illona, Pat, Jerry Mike

MEMORANDUM

****

To: Commissioners Wefald, Clark, and Reinbold
Jon Mielke, Legal, PUD
From: Patrick Fahn
Date: February 17, 2003

RE: Sole Source contract for consultant – MDU depreciation study review – Case No. PU-399-02-183

On December 18, 2002, the Commission issued its order in Case No. PU-399-02-183. On January 31, 2003, Montana Dakota Utilities Co. filed its depreciation study in compliance with the Commission's order. The Commission order stated that it intends to complete its review of the depreciation study by July 31, 2003. Because of the time frame in which the Commission needs to complete its study, staff recommends that the Commission hire a consultant under the Commission's sole source procurement procedures.

Sole source procurement can be used in unique situations when the lengthy process of bid solicitation cannot be utilized. When sole source procurement is proposed, written justification must be presented to the Commission for approval.

The Commission's procedures provide the following reasons that sole source procurement may be justified:

1. The proposed item or service is available only from a single source.

2. The person or organization has the unique product or the special skills, knowledge, abilities to provide the required services (at the exclusion of others) and is considered the preeminent deliverer of that product or service at the time of selection.

3. Emergency of severe time constraints preclude issuing a formal Request for Proposal.

4. The service is available within the existing structure of state of local government.

Staff primary justification for sole source procurement is that Snavely King Majaros O'Connor & Lee, Inc., the consultant retained under competitive bidding procedures in this proceeding, already has significant information relating to MDU's investments and its financial structure and operations in North Dakota, and the MDU depreciation issues. This consultant will be able to complete the project within the 6-month time frame at a reasonable cost.

A second justification for sole source procurement in this proceeding is that the Commission intends to complete the analysis of the depreciation study within 6 months.

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

RECEIVED
JAN 31 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

January 31, 2003

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Depreciation Study
Case No PU-399-02-183

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of the depreciation studies for its gas and common plant as required by the Order of the Commission issued on December 18, 2002 in the above referenced case.

The studies were prepared by AUS Consultants. In summary, the total company annual depreciation expense for gas plant increases by $315,635 from the current annual depreciation expense based on December 31, 2001 plant in service. The composite annual depreciation rate for gas plant goes from the current 4.52 percent to 4.70 percent. The total company annual depreciation expense for common plant increased by $499,417 from the current annual depreciation expense based on December 31, 2001 plant in service. The composite annual depreciation rate for common plant goes from the current 5.84 percent to 7.18 percent.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,

Donald R. Ball

Donald R. Ball
Director of Regulatory Affairs

Attachments
cc: D. Schulz

118 PU-399-02-183 Pages: 1
Letter re Depreciation Study
by Montana-Dakota Utilities Co., a Division of MDU R
01/31/2003 CC: Comm Legal Illona, Pat, Jerry Mike

RECEIVED
JAN 3 1
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

MONTANA-DAKOTA UTILITIES CO.
GAS DIVISION

Depreciation Study
as of December 31, 2001

AUS CONSULTANTS
Utility Services
Weber Fick & Wilson Division

117 **PU-399-02-183** Pages: 154

MDU Depreciation Study as of 12/31/01

by Montana-Dakota Utilities Co., a Division of MDU Re

01/31/2003 CC: Comm Legal Illona, Pat, Jerry Mike

Earl M. Robinson, CDP
President & CEO

AUS CONSULTANTS
Utility Services
Weber Fick & Wilson Division
1000 N. Front St., Suite 200
Wormleysburg, PA 17043
(717) 763-9890
FAX: (717) 763-9931
INTERNET: http://www.ausinc.com
E-MAIL: erobinson@wfw-ausinc.com

January 27, 2003

Mr. Paul Bienek
Montana-Dakota Utilities Company
400 North Fourth Street
Bismark, ND 58501

Dear Mr. Bienek:

In accordance with your authorization, we have prepared a depreciation study related to the utility plant in service of Montana-Dakota Utilities Company - Gas Division as of December 31, 2001. Our findings and recommendations, together with supporting schedules and exhibits, are set forth in the accompanying report.

Summary schedules have been prepared to illustrate the impact of instituting the recommended annual depreciation rates as a basis for the Company's annual depreciation expense as compared to the rates presently utilized. The application of the present rates to the depreciable plant in service as of December 31, 2001 results in an annual depreciation expense of $7,694,754. In comparison, the application of the proposed depreciation rates to the depreciable plant in service at December 31, 2001 results in an annual depreciation expense of $8,010,389, which is a increase of $315,635 from current rates. The composite annual depreciation rate under present rates is 4.52 percent, while the proposed proforma composite depreciation rate is 4.70 percent.

Section 2 of our report contains the summary schedules showing the results of our service life and salvage studies and summaries of presently utilized depreciation rates. The subsequent sections of the report present a detailed outline of the methodology and procedures used in the study together with supporting calculations and analyses used in the development of the results. A detailed table of contents follows this letter.

Respectfully submitted,

Earl M Robinson

EARL M. ROBINSON, CDP

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MONTANA-DAKOTA UTILITIES COMPANY
Gas Division

Executive Summary

Table 1 on pages 2-1 to 2-2 is a comparative summary which illustrates the effect of instituting the revised depreciation rates. The schedule includes a comparison of the annual depreciation rates and annual depreciation expense under both present and proposed rates applied using the Straight Line Method for each depreciable property group of the Montana-Dakota Utilities Company-Gas Division (the "Company") plant in service as of December 31, 2001. Both the present and proposed depreciation rates were developed utilizing the Straight Line (SL) Method, Broad Group (BG) Procedure, and the Average Remaining Life (ARL) Technique.

Table 2 on pages 2-3 to 2-5 provides a summary of the detailed life estimates and service life parameters (Iowa Curves) utilized in preparing the Average Remaining Life depreciation rates for each property group. The schedule provides a summary of the detailed data and narrative of the study results set forth in Sections 4 through 7. The developed depreciation rates (Column L) were determined by studying the Company's historical investment data together with the interpretation of future life expectancies which will have a bearing on the overall service life of the Company's property.

Table 3 on page 2-6 contains the allocation of the Company's book depreciation reserve for selected depreciable property groups. Each of the applicable property group's book depreciation reserves were proportionally distributed to each asset sub-account group based upon the theoretical depreciation reserve. The theoretical depreciation reserve was developed using each asset category's utility plant in service as of December

31, 2001 together with the current estimated service life characteristics and net salvage factors developed per the study.

Table 4 on page 2-7 is a summary schedule showing the impact on the Company's annual depreciation expense as a result of estimating current average service lives for the applicable general plant accounts as well as changing from depreciating the property groups to a straight line amortization of the investment over a set period of years.

The various schedules comprising Table 5 on pages 2-8 to 2-26 summarize the development of the annual amortization amounts for each of the general plant accounts for which the depreciation amortization approach is being proposed. The proposal to amortize the investments within the selected general plant accounts is driven by the Company's ongoing difficulty to effectively track various of the property account investments that are in many cases related to a large quantity of items of corresponding small investment amounts. Due to the inability to effectively track the items, many times the items are no longer utilized but remain on the company's books and records as unrecorded retirements. Therefore to simplify the accounting procedure for these property items it is proposed that the investments within each vintage of the applicable property group be amortized over a predetermined time period. Once attaining the stated amortization period age the asset's original cost investment will have been fully amortized, and accordingly, will be retired from the company's books and records. The property accounts for which asset investment amortization is being proposed includes Account 391, 393, 394, 395, 397, and 398.

In the process of moving from depreciation to amortization of the selected general plant accounts, there are, by the very nature of average service life dispersion, vintage

investments within the applicable property groups which exceeds the estimated average service life / proposed amortization period. Given that each vintage of property will be amortized over the average service life, an adjustment needs to be incorporated into the change-over process to recover the under depreciated portion of the older investments. Accordingly, the variance between the amortization starting-point depreciation reserve and the Company's actual book reserve (either positive or negative) is being recorded on a straight line basis over the proposed amortization period along with the annual amortization of all other vintage investments. The amortization starting point book depreciation reserve is equal to the sum of the original cost for vintages older than the amortization period plus the calculated deprecation reserve for vintages with ages equal to or less than the amortization period .

The utilization of the recommended depreciation rates based upon the Straight Line Average Remaining Life Procedure results in the setting of depreciation rates which will continuously true up the Company's level of capital recovery over the life of each asset group. Application of this procedure, which is based upon the current best estimates of service life together with the Company's plant in service and accrued depreciation, produces annual depreciation rates that will result in the Company recovering 100 percent of its investment -- no more, no less.

It is recommended that the Company continue to apply depreciation rates and maintain its book depreciation reserve on an account-level basis. The maintenance of the book reserve on an account-level basis requires both the development of annual depreciation expense and distribution of other reserve account charges to an individual level. Maintaining the Company's depreciation records in this detail will aid in completing

the various rate studies and, most importantly, clearly identifies the Company's level of capital recovery relative to each category of plant investment.

The general drivers for the proposed depreciation rates include an assessment of the Company's historical experience with regard to achieved service lives and net salvage factors. In addition, consideration is given to current and anticipated events which are anticipated to impact the Company's ability to recover its fixed capital costs related to utility plant in service utilized to provide service to the Company's customers.

The depreciation rate for each individual account changed as a result of reflecting estimates obtained through the in-depth analysis of the Company's most recent data together with an interpretation of ongoing and anticipated future events. Some of the revisions were not significant and typically reflect fine tuning of previously utilized depreciation rates while others were more substantial in nature. Several of the accounts did reflect more significant changes (as outlined in Section 4 of this report) from the previously utilized depreciation rates.

The most notable depreciation/amortization occurred relative to Account 376 - Distribution Mains, Account 380 - Services, Account 381 - Meters, Account 392 - Transportation Equipment, and Account 396.2 - Power Operated Equipment.

The depreciation rate relative to Account 381 - Meters increased from 2.58 percent to 3.19 percent. This depreciation expense increase is the product of incorporating the estimated average service life and net salvage factors identified through an in depth analysis of the Company's historical experience and future expectations.

The depreciation rate for Account 392.2 - Transportation Equipment - Utilized increased from 5.74 percent to 21.13 percent. The proposed depreciation rate is the

product of the application of applicable service lives to each of the various property categories which comprise the overall property account. Furthermore, the depreciation rate increase is also being driven by the fact that the Company's current book depreciation reserve for this property account is low in comparison to the achieved age of the property group investment.

Conversely, several of the property groups experienced depreciation rate decreases from the current levels.

The composite depreciation rate for Account 376 - Mains declined from 4.05 percent to 3.15 percent. The decrease of the deprecation rate for this property group is a composite of a longer average service life as compared to that underlying the present depreciation rate as well as the impact of the Company's book depreciation reserve being higher than the applicable theoretical depreciation reserve.

The depreciation/amortization rate for Account 380 - Services declined from 7.60 percent to 7.03 percent and is being driven by the application of the current estimated average service life and net salvage factors.

Likewise the annual depreciation rate relative to Account 396.2 - Power Operated Equipment declined from 4.83 percent to zero (0) percent. This depreciation rate change is being driven by the Company's experienced level of average service life, achieved net salvage and corresponding current level of accrued depreciation in comparison to the current age of the property. This circumstance is the product of the Company's current experience and practice of continuously upgrading its principal Power Operating Equipment which results in high trade-in values.

Various of the remaining account/sub-accounts experienced increases and/or

declines in recommended depreciation rates to a lesser degree, as noted per Table 1 of this report. This revision in annual depreciation rates and expense is the result of both changes in the estimated service lives and salvage factors, and reflects the impact of the Company's property changes since the most recent study.

With regard to the inclusion of higher negative net salvage levels in the development of proposed depreciation rates, as noted within the discussion related to net salvage in Section 3 of the depreciation report, it is highlighted that the level of experienced net salvage should simply be a benchmark from which to estimate future net salvage. It is highly likely that the negative net salvage amounts experienced even recently will simply be the floor above which future negative net salvage levels will increase to a higher level. To appropriately and proportionately allocate the true total asset cost (original cost adjusted for net salvage) over its applicable service life, proper consideration must be given in each accounting period, to the total costs that are anticipated to occur relative to the Company's assets that provide customer service.

Applying the proposed depreciation /amortization rates to the Company's December 31, 2001 plant in service produces annual depreciation expense of $8,010,389 which is a increase of $315,635 from current depreciation rates.

The following summary compares the present and proposed composite depreciation rates for illustrative purposes only. The Composite Depreciation Rate should not be applied to the total Company investment inasmuch as the non-proportional change in plant investment as a result of property additions or retirements would render the composite rate inappropriate. The Table 1 schedule lists the recommended annual depreciation rates for each property account.

Present Depreciation Rates

Depreciable Plant In Service at December 31, 2001	$170,378,791
Annual Depreciation Expense	7,694,754
Composite Annual Depreciation Rate	4.52%

Proforma Proposed Depreciation Rates

Depreciable Plant In Service at December 31, 2001	$170,378,791
Annual Depreciation Expense	8,010,389
Composite Annual Depreciation Rate	4.70%

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	Distribution Plant						
374.20	Rights of Way	89,641.04	2.58%	2,312.74	0.75%	672.31	-1,640.43
375.00	Distr. Meas & Reg Station Structures	521,210.22	2.40%	12,509.05	3.24%	16,887.21	4,378.16
	Mains						
376.10	Mains-Steel	33,849,069.40	4.05%	1,370,887.31	2.89%	978,238.11	-392,649.20
376.20	Mains-Plastic	44,012,975.20	4.05%	1,782,525.50	3.35%	1,474,434.67	-308,090.83
376.30	Mains-Valves	391,503.88	4.05%	15,855.91	3.78%	14,798.85	-1,057.06
376.40	Mains-Manholes	69,919.29	4.05%	2,831.73	3.25%	2,272.38	-559.35
376.50	Mains-Bridge & River Crossings	10,685.81	4.05%	432.78	3.47%	370.80	-61.98
	Total Mains	78,334,153.58	4.05%	3,172,533.23	3.15%	2,470,114.81	-702,418.42
378.00	Meas & Reg Station Equip-General	1,367,333.67	2.30%	31,448.67	3.31%	45,258.74	13,810.07
379.00	Meas & Reg Station Equip-City Gate	1,009,136.85	2.74%	27,650.35	4.33%	43,695.63	16,045.28
	Services						
380.10	Services-Steel	7,683,869.79	7.60%	583,974.10	7.14%	548,628.30	-35,345.80
380.20	Services-Plastic	24,580,506.89	7.60%	1,868,118.52	6.97%	1,713,261.33	-154,857.19
380.30	Farm & Fuel Lines	212,340.42	7.60%	16,137.87	9.33%	19,811.36	3,673.49
	Total Services	32,476,717.10	7.60%	2,468,230.49	7.03%	2,281,700.99	-186,529.50
381.00	Meters	30,462,008.09	2.58%	785,919.81	3.19%	971,738.06	185,818.25
383.00	Service Regulators	4,296,861.63	2.37%	101,835.62	2.87%	123,319.93	21,484.31
385.00	Industrial Meas. & Reg. Station Equipment	578,200.01	1.91%	11,043.62	3.77%	21,798.14	10,754.52
	MISCELLANEOUS EQUIPMENT						
386.10	Miscellaneous Property on Customers Premise	1,679.84	9.35%	157.07	5.19%	87.18	-69.89
386.20	CNG Refueling station	432,811.48	9.35%	40,467.87	3.70%	16,014.02	-24,453.85
	TOTAL Account 386	434,491.32	9.35%	40,624.94	3.71%	16,101.20	-24,523.74
	OTHER EQUIPMENT						
387.10	Cathodic Protection Equipment	1,450,657.25	5.21%	75,579.24	5.75%	83,412.79	7,833.55
387.20	Other Distribution Equipment	557,183.52	5.21%	29,029.26	1.42%	7,912.01	-21,117.25
	TOTAL Account 387	2,007,840.77	5.21%	104,608.50	4.55%	91,324.80	-13,283.70
	TOTAL Distribution Plant	151,577,594.28	4.46%	6,758,717.02	4.01%	6,082,611.82	-676,105.20
	General Plant						
390.00	General Structures	1,922,983.06	2.34%	44,997.80	4.61%	88,649.52	43,651.72
	OFFICE FURNITURE & EQUIPMENT						
391.10	Office Furniture & Equipment	544,274.64	4.05%	22,043.12	4.97%	27,033.65	4,990.53
391.30	Computer Equipment - PC	780,994.56	12.50%	97,624.32	26.02%	203,214.78	105,590.46
	TOTAL Account 391	1,325,269.20	9.03%	119,667.44	17.37%	230,248.43	110,580.99
	TRANSPORTATION EQUIPMENT						
392.10	Transportation Equipment (Trailers)	147,186.67	5.74%	8,448.51	4.36%	6,417.34	-2,031.17
392.20	Transportation Equipment (Cars & Trucks)	6,080,561.05	5.74%	349,024.20	21.13%	1,284,822.55	935,798.35
	TOTAL Account 392	6,227,747.72	5.74%	357,472.71	20.73%	1,291,239.89	933,767.18
393.00	Stores Equipment	186,729.06	0.90%	1,680.56	2.49%	4,658.15	2,977.59
	TOOLS, SHOP & GARAGE EQ.						
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,421.95	3.57%	89,086.56	6.62%	165,153.11	76,066.55
394.20	Tools, Shop & Garage Equip. (Unitized)	299,809.93	4.83%	14,480.82	2.40%	7,200.70	-7,280.12
394.30	Vehicle Maintenance Equipment	31,176.58	4.21%	1,312.53	5.78%	1,803.27	490.74
394.40	Vehicle Refueling Equipment	361,344.00	9.35%	33,785.66	4.72%	17,065.14	-16,720.52
	TOTAL Account 394	3,187,752.46	4.35%	138,665.57	6.00%	191,222.22	52,556.65
395.00	Laboratory Equipment	271,033.04	2.32%	6,287.97	7.67%	20,800.98	14,513.01

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2001 and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	POWER OPERATED EQUIPMENT						
396.10	Work Equipment (Trailers)	293,543.45	4.83%	14,178.15	5.76%	16,908.10	2,729.95
396.20	Power Operated Equipment	4,081,768.33	4.83%	197,149.41	0.00%	0.00	-197,149.41
	TOTAL Account 396	4,375,311.78	4.83%	211,327.56	0.39%	16,908.10	-194,419.46
	COMMUNICATION EQUIPMENT						
397.10	Radio Communication Equip. (Fixed)	481,655.16	3.67%	17,676.74	7.37%	35,510.67	17,833.93
397.20	Radio Communication Equip. (Mobile)	401,528.27	3.67%	14,736.09	7.34%	29,468.63	14,732.54
397.30	General Telephone Communication Equip.	90,517.88	6.56%	5,937.97	9.88%	8,941.08	3,003.11
397.50	Supervisory & Telemetering Equip.	124,167.15	6.67%	8,281.95	0.25%	310.92	-7,971.03
397.60	SCADA System	30,894.36	15.07%	4,655.78	0.00%	0.00	-4,655.78
397.80	Network Equipment	30,337.55	12.50%	3,792.19	26.26%	7,967.96	4,175.77
	TOTAL Account 397	1,159,100.37	4.75%	55,080.72	7.09%	82,199.26	27,118.54
398.00	Miscellaneous Equipment	145,269.53	0.59%	857.09	1.27%	1,851.12	994.03
	Sub-Total (General Plant) Amortization	**5,494,159.10**	**4.09%**	**224,615.03**	**5.97%**	**327,765.38**	**103,150.35**
	TOTAL General Plant	18,801,196.22	4.98%	936,037.42	10.25%	1,927,777.67	991,740.25
	TOTAL Depreciable Plant	170,378,790.50	4.52%	7,694,754.44	4.70%	8,010,389.49	315,635.05
	NON-DEPRECIABLE PLANT						
374.10	Land (Distribution)	108,919.96					
389.00	Land & Land Rights (General)	301,148.77					
	Total Land	410,068.73					
	INTANGIBLE PLANT						
303.00	Miscellaneous Intangible Plant	477,529.69					
	Total Intangible Plant	477,529.69					
	TOTAL Non-Depreciable Plant	887,598.42					
	TOTAL Plant in Service	171,266,388.92					

Table 2

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	Distribution Plant										
374.20	Rights of Way	89,641.04	0%	0.00	89,641.04	56,339.70	33,301.34	65-R2.5	49.3	675.48	0.75%
375.00	Distr. Meas & Reg Station Structures	521,210.22	-50%	-260,605.11	781,815.33	277,078.77	504,736.56	55-R2.5	29.9	16,880.82	3.24%
	Mains										
376.10	Mains-Steel	33,849,069.40	-60%	-20,309,441.64	54,158,511.04	33,256,163.25	20,902,347.79	45-R3	21.4	976,745.22	2.89%
376.20	Mains-Plastic	44,012,975.20	-60%	-26,407,785.12	70,420,760.32	20,700,695.85	49,720,064.47	45-R3	33.7	1,475,372.83	3.35%
376.30	Mains-Valves	391,503.88	-60%	-234,902.33	626,406.21	176,722.46	449,683.75	40-R2.5	30.4	14,792.23	3.78%
376.40	Mains-Manholes	69,919.29	-60%	-41,951.57	111,870.86	43,845.92	68,024.94	45-R3	29.9	2,275.08	3.25%
376.50	Mains-Bridge & River Crossings	10,685.81	-60%	-6,411.49	17,097.30	2,604.26	14,493.04	45-R3	39.1	370.67	3.47%
	Total Mains	78,334,153.58		-47,000,492.15	125,334,645.73	54,180,031.74	71,154,613.99			2,469,556.03	3.15%
378.00	Meas & Reg Station Equip-General	1,367,333.67	-30%	-410,200.10	1,777,533.77	724,343.90	1,053,189.87	40-R1	23.3	45,201.28	3.31%
379.00	Meas & Reg Station Equip-City Gate	1,009,136.85	-15%	-151,370.53	1,160,507.38	334,884.86	825,622.52	35-R2.5	18.9	43,683.73	4.33%
	Services										
380.10	Services-Steel	7,683,869.79	-175%	-13,446,772.13	21,130,641.92	10,815,899.93	10,314,741.99	40-R2.5	18.8	548,656.49	7.14%
380.20	Services-Plastic	24,580,506.89	-175%	-43,015,887.06	67,596,393.95	17,902,011.01	49,694,382.94	40-R3	29.0	1,713,599.41	6.97%
380.30	Farm & Fuel Lines	212,340.42	-175%	-371,595.74	583,936.16	175,878.83	408,057.33	30-R1.5	20.6	19,808.61	9.33%
	Total Services	32,476,717.10		-56,834,254.93	89,310,972.03	28,893,789.76	60,417,182.27			2,282,064.51	7.03%
381.00	Meters	30,462,008.09	0%	0.00	30,462,008.09	11,110,550.60	19,351,457.49	35-R2.5	19.9	972,435.05	3.19%
383.00	Service Regulators	4,296,861.63	10%	429,686.16	3,867,175.47	1,645,380.97	2,221,794.50	35-R3	18.0	123,433.03	2.87%
385.00	Industrial Meas. & Reg. Station Equipment	578,200.01	-15%	-86,730.00	664,930.01	215,548.96	449,381.05	35-R2	20.6	21,814.61	3.77%
	MISCELLANEOUS EQUIPMENT										
386.10	Miscellaneous Property on Customers Premise	1,679.84	0%	0.00	1,679.84	747.62	932.22	15-R3	10.7	87.12	5.19%
386.20	CNG Refueling station	432,811.48	0%	0.00	432,811.48	303,145.03	129,666.45	15-R3	8.1	16,008.20	3.70%
	TOTAL Account 386	434,491.32		0.00	434,491.32	303,892.65	130,598.67			16,095.33	3.70%
	OTHER EQUIPMENT										
387.10	Cathodic Protection Equipment	1,450,657.25	0%	0.00	1,450,657.25	607,867.20	842,790.05	20-R1.5	10.1	83,444.56	5.75%
387.20	Other Distribution Equipment	557,183.52	0%	0.00	557,183.52	416,739.73	140,443.79	25-R3	17.8	7,890.10	1.42%
	TOTAL Account 387	2,007,840.77		0.00	2,007,840.77	1,024,606.93	983,233.84			91,334.66	4.55%
	TOTAL Distribution Plant	151,577,594.28		-104,313,966.66	255,891,560.94	98,766,448.84	157,125,112.10			6,083,174.54	4.01%
	General Plant										
390.00	General Structures	1,922,983.06	-10%	-192,298.31	2,115,281.37	1,113,319.44	1,001,961.93	35-R3	11.3	88,669.20	4.61%

Table 2

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	OFFICE FURNITURE & EQUIPMENT										
391.10	Office Furniture & Equipment	544,274.64	5%	27,213.73	517,060.91	308,168.66	208,892.25 (1)	15-R1	N/A	27,033.65	4.97%
391.30	Computer Equipment - PC	780,994.56	0%	0.00	780,994.56	293,350.52	487,644.04 (1)	5-R2	2.4	203,185.02	26.02%
	TOTAL Account 391	1,325,269.20		27,213.73	1,298,055.47	601,519.18	696,536.29			230,218.67	17.37%
	TRANSPORTATION EQUIPMENT										
392.10	Transportation Equipment (Trailers)	147,186.67	15%	22,078.00	125,108.67	91,105.72	34,002.95	8-R3	5.3	6,415.65	4.36%
392.20	Transportation Equipment (Cars & Trucks)	6,080,561.05	15%	912,084.16	5,168,476.89	2,213,864.76	2,954,612.13	6-R3	2.3	1,284,613.97	21.13%
	TOTAL Account 392	6,227,747.72			5,293,585.56	2,304,970.48	2,988,615.08			1,291,029.62	20.73%
393.00	Stores Equipment	186,729.06	0%	0.00	186,729.06	126,411.86	60,317.20 (1)	35-R3	N/A	4,658.15	2.49%
	TOOLS, SHOP & GARAGE EQ.										
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,421.95	10%	249,542.20	2,245,879.75	1,213,026.66	1,032,853.09 (1)	18-R1.5	N/A	165,153.11	6.62%
394.20	Tools, Shop & Garage Equip. (Unitized)	299,809.93	10%	29,980.99	269,828.94	302,930.33	-33,101.39 (1)	18-R1	N/A	7,200.70	2.40%
394.30	Vehicle Maintenance Equipment	31,176.58	0%	0.00	31,176.58	11,255.54	19,921.04 (1)	20-R3	N/A	1,803.27	5.78%
394.40	Vehicle Refueling Equipment	361,344.00	0%	0.00	361,344.00	234,336.79	127,007.21 (1)	15-R3	N/A	17,065.14	4.72%
	TOTAL Account 394	3,187,752.46		279,523.19	2,908,229.27	1,761,549.32	1,146,679.95			191,222.21	6.00%
395.00	Laboratory Equipment	271,033.04	0%	0.00	271,033.04	57,665.05	213,367.99 (1)	20-R2	N/A	20,800.98	7.67%
	POWER OPERATED EQUIPMENT										
396.10	Work Equipment (Trailers)	293,543.45	35%	102,740.21	190,803.24	91,088.92	99,714.32	10-R2	5.9	16,900.73	5.76%
396.20	Power Operated Equipment	4,081,768.33	60%	2,449,061.00	1,632,707.33	2,254,639.91	-621,932.58	7-R2	3.2	0.00	0.00% (2)
	TOTAL Account 396	4,375,311.78		2,551,801.21	1,823,510.57	2,345,728.83	-522,218.26			16,900.73	0.39%
	COMMUNICATION EQUIPMENT										
397.10	Radio Communication Equip. (Fixed)	481,655.16	0%	0.00	481,655.16	255,394.36	226,260.80 (1)	15-R3	N/A	35,510.67	7.37%
397.20	Radio Communication Equip. (Mobile)	401,528.27	0%	0.00	401,528.27	170,152.35	231,375.92 (1)	15-R3	N/A	29,468.63	7.34%
397.30	General Telephone Communication Equip.	90,517.88	0%	0.00	90,517.88	34,571.00	55,946.88 (1)	10-R1	N/A	8,941.08	9.88%
397.50	Supervisory & Telemetering Equip.	124,167.15	0%	0.00	124,167.15	123,660.97	506.18 (1)	10-L1	N/A	310.92	0.25%
397.60	SCADA System	30,894.36	0%	0.00	30,894.36	30,894.36	0.00 (1)	8-R3	N/A	0.00	0.00%
397.80	Network Equipment	30,337.55	0%	0.00	30,337.55	11,889.89	18,447.66 (1)	5-R3	N/A	7,967.96	26.26%
	TOTAL Account 397	1,159,100.37		0.00	1,159,100.37	626,562.93	532,537.44			82,199.26	7.09%
398.00	Miscellaneous Equipment	145,269.53	0%	0.00	145,269.53	70,042.49	75,227.04 (1)	20-R2	N/A	1,851.12	1.27%
	TOTAL General Plant	18,801,196.22		0.00	15,200,794.24	9,007,769.58	6,193,024.66			1,927,549.93	10.25%
	TOTAL Depreciable Plant	170,378,790.50		-104,313,966.66	271,092,355.18	107,774,218.42	163,318,136.76			8,010,724.46	4.70%

Table 2

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	NON-DEPRECIABLE PLANT										
374.10	Land (Distribution)	108,919.96									
389.00	Land & Land Rights (General)	301,148.77									
						0.00					
	Total Land	410,068.73									
	INTANGIBLE PLANT										
303.00	Miscellaneous Intangible Plant	477,529.69				437,461.01					
	Total Intangible Plant	477,529.69				437,461.01					
	TOTAL Non-Depreciable Plant	887,598.42				437,461.01					
	TOTAL Plant in Service	171,266,388.92				108,211,679.43					

(1) Implicit Depreciation Rates and Annual Accrual Based Upon General Plant Amortization Calculation
(2) Account Fully Depreciated. See Narrative In Section 4.

Montana-Dakota Utilities Company
Gas Divisivion

Allocation of Book Depreciation Reserve as of December 31, 2001
Based Upon the Calculated Depreciation Reserve as of December 31, 2001

Account No. (a)	Description (b)	Cost 12/31/01 (c)	A.S.L./ Curve (d)	Salvage % (e)	Theoretical Deprecation Reserve (f)	Allocated Book Depr. Reserve (g)
	Mains					
376.10	Mains-Steel	33,849,069.40	45-R3	-60%	28,444,887.67	33,256,163.25
376.20	Mains-Plastic	44,012,975.20	45-R3	-60%	17,705,859.92	20,700,695.85
376.30	Mains-Valves	391,503.88	40-R2.5	-60%	151,155.46	176,722.46
376.40	Mains-Manholes	69,919.29	45-R3	-60%	37,502.59	43,845.92
376.50	Mains-Bridge & River Crossings	10,685.81	45-R3	-60%	2,227.49	2,604.26
	Total Mains				46,341,633.13	54,180,031.74
	Services					
380.10	Services-Steel	7,683,869.79	40-R2.5	-175%	11,209,322.80	10,815,899.93
380.20	Services-Plastic	24,580,506.89	40-R3	-175%	18,553,187.58	17,902,011.01
380.30	Farm & Fuel Lines	212,340.42	30-R1.5	-175%	182,276.33	175,878.83
	Total Services				29,944,786.71	28,893,789.76

Table 4

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation/Amortization Expense
Under Present Rates and Proposed Amortization

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Amortization Rate % (f)	Proposed Amortization Annual Accrual (g)	Net Change Depr/Amort Expense (h)
	DEPRECIABLE PLANT						
	General Plant						
	GENERAL STRUCTURES						
	OFFICE FURNITURE & EQUIPMENT						
391.10	Office Furniture & Equipment	544,274.64	4.05%	22,043.12	4.97%	27,033.65	4,990.53
393.00	Stores Equipment	186,729.06	0.90%	1,680.56	2.49%	4,658.15	2,977.59
	TOOLS, SHOP & GARAGE EQ.						
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,421.95	3.57%	89,086.56	6.62%	165,153.11	76,066.55
394.20	Tools, Shop & Garage Equip. (Unitized)	299,809.93	4.83%	14,480.82	2.40%	7,200.70	-7,280.12
394.30	Vehicle Maintenance Equipment	31,176.58	4.21%	1,312.53	5.78%	1,803.27	490.74
394.40	Vehicle Refueling Equipment	361,344.00	9.35%	33,785.66	4.72%	17,065.14	-16,720.52
	TOTAL Account 394	3,187,752.46	4.35%	138,665.57	6.00%	191,222.22	52,556.65
395.00	Laboratory Equipment	271,033.04	2.32%	6,287.97	7.67%	20,800.98	14,513.01
	COMMUNICATION EQUIPMENT						
397.10	Radio Communication Equip. (Fixed)	481,655.16	3.67%	17,676.74	7.37%	35,510.67	17,833.93
397.20	Radio Communication Equip. (Mobile)	401,528.27	3.67%	14,736.09	7.34%	29,468.63	14,732.54
397.30	General Telephone Communication Equip.	90,517.88	6.56%	5,937.97	9.88%	8,941.08	3,003.11
397.50	Supervisory & Telemetering Equip.	124,167.15	6.67%	8,281.95	0.25%	310.92	-7,971.03
397.60	SCADA System	30,894.36	15.07%	4,655.78	0.00%	0.00	-4,655.78
397.80	Network Equipment	30,337.55	12.50%	3,792.19	26.26%	7,967.96	4,175.77
	TOTAL Account 397	1,159,100.37	4.75%	55,080.72	7.09%	82,199.26	27,118.54
398.00	Miscellaneous Equipment	145,269.53	0.59%	857.09	1.27%	1,851.12	994.03
	Sub-Total (General Plant) Amortization	**5,494,159.10**	**4.09%**	**224,615.03**	**5.97%**	**327,765.38**	**103,150.35**

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 391.10 - Office Furniture & Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1932	4,605.04	4,375	(1)	4,605.04	0.00	0	0.00
1933	4,720.16	4,484	(1)	4,720.16	0.00	0	0.00
1934	4,838.17	4,596	(1)	4,838.17	0.00	0	0.00
1935	572.05	543	(1)	572.05	0.00	0	0.00
1936	1,095.98	1,041	(1)	1,095.98	0.00	0	0.00
1937	1,223.06	1,162	(1)	1,223.06	0.00	0	0.00
1938	1,353.31	1,286	(1)	1,353.31	0.00	0	0.00
1939	1,486.82	1,412	(1)	1,486.82	0.00	0	0.00
1940	1,623.67	1,542	(1)	1,623.67	0.00	0	0.00
1941	0.00	0	(1)	0.00	0.00	0	0.00
1942	0.00	0	(1)	0.00	0.00	0	0.00
1943	0.00	0	(1)	0.00	0.00	0	0.00
1944	0.00	0	(1)	0.00	0.00	0	0.00
1945	0.00	0	(1)	0.00	0.00	0	0.00
1946	1,623.67	1,542	(1)	1,623.67	0.00	0	0.00
1947	1,623.67	1,542	(1)	1,623.67	0.00	0	0.00
1948	1,623.67	1,542	(1)	1,623.67	0.00	0	0.00
1949	1,623.67	1,542	(1)	1,623.67	0.00	0	0.00
1950	1,981.49	1,882	(1)	1,981.49	0.00	0	0.00
1951	8,252.35	7,840	(1)	8,252.35	0.00	0	0.00
1952	10,124.49	9,618	(1)	10,124.49	0.00	0	0.00
1953	1,675.30	1,592	(1)	1,675.30	0.00	0	0.00
1954	5,978.65	5,680	(1)	5,978.65	0.00	0	0.00
1955	11,466.37	10,893	(1)	11,466.37	0.00	0	0.00
1956	15,979.68	15,181	(1)	15,979.68	0.00	0	0.00
1957	4,672.90	4,439	(1)	4,672.90	0.00	0	0.00
1958	2,895.25	2,750	(1)	2,895.25	0.00	0	0.00
1959	8,266.43	7,853	(1)	8,266.43	0.00	0	0.00
1960	12,190.08	11,581	(1)	12,190.08	0.00	0	0.00
1961	6,523.95	6,198	(1)	6,523.95	0.00	0	0.00
1962	11,986.55	11,387	(1)	11,986.55	0.00	0	0.00
1963	6,144.10	5,837	(1)	6,144.10	0.00	0	0.00
1964	12,954.93	12,307	(1)	12,954.93	0.00	0	0.00
1965	7,103.42	6,748	(1)	7,103.42	0.00	0	0.00
1966	12,419.03	11,798	(1)	12,419.03	0.00	0	0.00
1967	8,319.57	7,904	(1)	8,319.57	0.00	0	0.00
1968	9,375.91	8,907	(1)	9,375.91	0.00	0	0.00
1969	6,998.56	6,649	(1)	6,998.56	0.00	0	0.00
1970	4,090.25	3,886	(1)	4,090.25	0.00	0	0.00
1971	11,362.05	10,794	(1)	11,362.05	0.00	0	0.00
1972	10,984.80	10,088	(1)	10,984.80	0.00	0	0.00
1973	10,930.76	9,937	(1)	10,930.76	0.00	0	0.00
1974	9,787.88	8,715	(1)	9,787.88	0.00	0	0.00
1975	8,735.36	7,618	(1)	8,735.36	0.00	0	0.00
1976	5,040.24	4,304	(1)	5,040.24	0.00	0	0.00
1977	4,684.21	3,912	(1)	4,684.21	0.00	0	0.00
1978	5,546.27	4,521	(1)	5,546.27	0.00	0	0.00
1979	12,021.50	9,549	(1)	12,021.50	0.00	0	0.00
1980	18,723.22	14,462	(1)	18,723.22	0.00	0	0.00

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 391.10 - Office Furniture & Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1981	24,944.34	18,691	(1)	24,944.34	0.00	0	0.00
1982	26,742.13	19,392	(2)	26,742.13	0.00	0	0.00
1983	23,687.42	16,575	(2)	23,687.42	0.00	0	0.00
1984	16,424.42	11,056	(2)	16,424.42	0.00	0	0.00
1985	11,667.33	7,527	(2)	11,667.33	0.00	0	0.00
1986	6,298.35	3,879	(2)	6,298.35	0.00	0	0.00
1987	10,031.76	5,870	(2)	5,870.00	4,161.76	1	4,161.76
1988	6,004.27	3,320	(2)	3,320.00	2,684.27	2	1,342.14
1989	6,111.73	3,174	(2)	3,174.00	2,937.73	3	979.24
1990	5,969.99	2,891	(2)	2,891.00	3,078.99	4	769.75
1991	34,027.99	15,231	(2)	15,231.00	18,796.99	5	3,759.40
1992	3,510.40	1,438	(2)	1,438.00	2,072.40	6	345.40
1993	19,099.32	7,073	(2)	7,073.00	12,026.32	7	1,718.05
1994	12,943.96	4,269	(2)	4,269.00	8,674.96	8	1,084.37
1995	8,216.74	2,369	(2)	2,369.00	5,847.74	9	649.75
1996	12,579.64	3,094	(2)	3,094.00	9,485.64	10	948.56
1997	2,820.08	572	(2)	572.00	2,248.08	11	204.37
1998	2,737.78	436	(2)	436.00	2,301.78	12	191.82
1999	5,933.10	681	(2)	681.00	5,252.10	13	404.01
2000	8,854.29	616	(2)	616.00	8,238.29	14	588.45
2001	441.08	10	(2)	10.00	431.08	15	28.74
	544,274.61	399,603		456,036.48	88,238.13	3.16%	17,175.79
Book Reserve				308,168.66			
Starting Point Depreciation Reserve				456,036.48			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				147,867.82	147,867.82	15	9,857.85
Total Amortization Amount						4.97%	27,033.65

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 393- Stores Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 35
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1920	876.54	877	(1)	876.54	0.00	0	0.00
1921	898.45	898	(1)	898.45	0.00	0	0.00
1922	920.91	921	(1)	920.91	0.00	0	0.00
1923	943.94	944	(1)	943.94	0.00	0	0.00
1924	967.54	968	(1)	967.54	0.00	0	0.00
1925	991.73	992	(1)	991.73	0.00	0	0.00
1926	1,016.52	1,017	(1)	1,016.52	0.00	0	0.00
1927	1,041.94	1,042	(1)	1,041.94	0.00	0	0.00
1928	1,067.99	1,068	(1)	1,067.99	0.00	0	0.00
1929	1,094.69	1,095	(1)	1,094.69	0.00	0	0.00
1930	1,122.06	1,122	(1)	1,122.06	0.00	0	0.00
1931	1,150.10	1,150	(1)	1,150.10	0.00	0	0.00
1932	1,178.86	1,179	(1)	1,178.86	0.00	0	0.00
1933	1,208.33	1,208	(1)	1,208.33	0.00	0	0.00
1934	1,238.54	1,239	(1)	1,238.54	0.00	0	0.00
1935	1,269.50	1,270	(1)	1,269.50	0.00	0	0.00
1936	1,301.23	1,301	(1)	1,301.23	0.00	0	0.00
1937	1,333.76	1,334	(1)	1,333.76	0.00	0	0.00
1938	1,367.11	1,367	(1)	1,367.11	0.00	0	0.00
1939	1,401.28	1,401	(1)	1,401.28	0.00	0	0.00
1940	1,436.32	1,436	(1)	1,436.32	0.00	0	0.00
1941	0.00	0	(1)	0.00	0.00	0	0.00
1942	0.00	0	(1)	0.00	0.00	0	0.00
1943	0.00	0	(1)	0.00	0.00	0	0.00
1944	0.00	0	(1)	0.00	0.00	0	0.00
1945	0.00	0	(1)	0.00	0.00	0	0.00
1946	1,436.32	1,397	(1)	1,436.32	0.00	0	0.00
1947	1,436.32	1,389	(1)	1,436.32	0.00	0	0.00
1948	1,436.32	1,379	(1)	1,436.32	0.00	0	0.00
1949	789.40	752	(1)	789.40	0.00	0	0.00
1950	1,517.02	1,435	(1)	1,517.02	0.00	0	0.00
1951	1,573.73	1,478	(1)	1,573.73	0.00	0	0.00
1952	1,603.23	1,493	(1)	1,603.23	0.00	0	0.00
1953	981.21	907	(1)	981.21	0.00	0	0.00
1954	734.17	673	(1)	734.17	0.00	0	0.00
1955	7,012.16	6,378	(1)	7,012.16	0.00	0	0.00
1956	6,292.92	5,677	(1)	6,292.92	0.00	0	0.00
1957	1,071.47	958	(1)	1,071.47	0.00	0	0.00
1958	4,692.97	4,161	(1)	4,692.97	0.00	0	0.00
1959	430.38	378	(1)	430.38	0.00	0	0.00
1960	2,526.36	2,197	(1)	2,526.36	0.00	0	0.00
1961	553.94	477	(1)	553.94	0.00	0	0.00
1962	1,082.68	921	(1)	1,082.68	0.00	0	0.00
1963	1,045.67	879	(1)	1,045.67	0.00	0	0.00
1964	485.33	402	(1)	485.33	0.00	0	0.00
1965	9,479.05	7,748	(1)	9,479.05	0.00	0	0.00
1966	2,157.35	1,736	(1)	2,157.35	0.00	0	0.00
1967	1,651.60	1,307	(2)	1,307.00	344.60	1	344.60
1968	5,567.94	4,327	(2)	4,327.00	1,240.94	2	620.47
1969	516.52	394	(2)	394.00	122.52	3	40.84
1970	8,797.44	6,567	(2)	6,567.00	2,230.44	4	557.61
1971	9,040.24	6,599	(2)	6,599.00	2,441.24	5	488.25
1972	2,993.64	2,134	(2)	2,134.00	859.64	6	143.27
1973	5,710.69	3,969	(2)	3,969.00	1,741.69	7	248.81

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 393- Stores Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Propert

Average Service Life-Amortiztion (Years): 35
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1974	2,278.09	1,541	(2)	1,541.00	737.09	8	92.14
1975	967.22	636	(2)	636.00	331.22	9	36.80
1977	2,974.56	1,836	(2)	1,836.00	1,138.56	11	103.51
1978	7,363.43	4,393	(2)	4,393.00	2,970.43	12	247.54
1979	0.00	0	(2)	0.00	0.00	13	0.00
1980	2,475.39	1,370	(2)	1,370.00	1,105.39	14	78.96
1981	0.00	0	(2)	0.00	0.00	15	0.00
1982	608.44	309	(2)	309.00	299.44	16	18.72
1983	0.00	0	(2)	0.00	0.00	17	0.00
1984	0.00	0	(2)	0.00	0.00	18	0.00
1985	0.00	0	(2)	0.00	0.00	19	0.00
1986	2,247.72	930	(2)	930.00	1,317.72	20	65.89
1987	12,024.02	4,680	(2)	4,680.00	7,344.02	21	349.72
1988	0.00	0	(2)	0.00	0.00	22	0.00
1989	0.00	0	(2)	0.00	0.00	23	0.00
1990	761.71	238	(2)	238.00	523.71	24	21.82
1991	0.00	0	(2)	0.00	0.00	25	0.00
1992	14,689.00	3,830	(2)	3,830.00	10,859.00	26	417.65
1993	852.74	200	(2)	200.00	652.74	27	24.18
1994	11,358.34	2,355	(2)	2,355.00	9,003.34	28	321.55
1995	0.00	0	(2)	0.00	0.00	29	0.00
1996	1,284.52	196	(2)	196.00	1,088.52	30	36.28
1997	0.00	0	(2)	0.00	0.00	31	0.00
1998	0.00	0	(2)	0.00	0.00	32	0.00
1999	0.00	0	(2)	0.00	0.00	33	0.00
2000	697.76	29	(2)	29.00	668.76	34	19.67
2001	19,702.69	277	(2)	277.00	19,425.69	35	555.02
	186,729.04	114,761		120,282.34	66,446.70	2.59%	4,833.28
Book Reserve				126,411.86			
Starting Point Depreciation Reserve				120,282.34			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-6,129.52	-6,129.52	35	-175.13
Total Amortization Amount						2.49%	4,658.15

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 394.1 - Tools, Shop & Garage Equipment (Non-Unitized)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 18
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1946	2,768.79	2,492	(1)	2,768.79	0.00	0	0.00
1947	10,474.25	9,427	(1)	10,474.25	0.00	0	0.00
1948	10,474.25	9,427	(1)	10,474.25	0.00	0	0.00
1949	20,648.04	18,583	(1)	20,648.04	0.00	0	0.00
1950	17,472.71	15,725	(1)	17,472.71	0.00	0	0.00
1951	15,341.30	13,807	(1)	15,341.30	0.00	0	0.00
1952	11,046.82	9,942	(1)	11,046.82	0.00	0	0.00
1953	10,454.96	9,409	(1)	10,454.96	0.00	0	0.00
1954	5,192.39	4,673	(1)	5,192.39	0.00	0	0.00
1955	32,433.75	29,190	(1)	32,433.75	0.00	0	0.00
1956	19,335.83	17,402	(1)	19,335.83	0.00	0	0.00
1957	12,341.13	11,107	(1)	12,341.13	0.00	0	0.00
1958	13,607.12	12,246	(1)	13,607.12	0.00	0	0.00
1959	12,214.77	10,993	(1)	12,214.77	0.00	0	0.00
1960	22,642.61	20,378	(1)	22,642.61	0.00	0	0.00
1961	18,282.80	16,455	(1)	18,282.80	0.00	0	0.00
1962	26,929.12	24,236	(1)	26,929.12	0.00	0	0.00
1963	24,298.85	21,869	(1)	24,298.85	0.00	0	0.00
1964	34,075.59	30,668	(1)	34,075.59	0.00	0	0.00
1965	30,108.83	27,098	(1)	30,108.83	0.00	0	0.00
1966	22,527.64	19,712	(1)	22,527.64	0.00	0	0.00
1967	10,291.19	8,923	(1)	10,291.19	0.00	0	0.00
1968	19,981.37	17,031	(1)	19,981.37	0.00	0	0.00
1969	19,473.45	16,314	(1)	19,473.45	0.00	0	0.00
1970	67,277.41	55,587	(1)	67,277.41	0.00	0	0.00
1971	18,320.87	14,937	(1)	18,320.87	0.00	0	0.00
1972	59,710.82	47,989	(1)	59,710.82	0.00	0	0.00
1973	40,496.89	32,045	(1)	40,496.89	0.00	0	0.00
1974	36,622.46	28,492	(1)	36,622.46	0.00	0	0.00
1975	31,287.00	23,907	(1)	31,287.00	0.00	0	0.00
1976	38,526.15	28,877	(1)	38,526.15	0.00	0	0.00
1977	43,861.56	32,212	(1)	43,861.56	0.00	0	0.00
1978	49,851.04	35,814	(1)	49,851.04	0.00	0	0.00
1979	79,790.49	55,978	(1)	79,790.49	0.00	0	0.00
1980	65,439.00	44,734	(1)	65,439.00	0.00	0	0.00
1981	45,439.51	30,190	(1)	45,439.51	0.00	0	0.00
1982	145,545.11	93,707	(1)	145,545.11	0.00	0	0.00
1983	159,927.81	99,454	(1)	159,927.81	0.00	0	0.00
1984	97,782.23	58,516	(2)	58,516.00	39,266.23	1	39,266.23
1985	141,942.76	81,412	(2)	81,412.00	60,530.76	2	30,265.38
1986	84,211.26	46,081	(2)	46,081.00	38,130.26	3	12,710.09
1987	14,238.35	7,396	(2)	7,396.00	6,842.35	4	1,710.59
1988	20,503.70	10,054	(2)	10,054.00	10,449.70	5	2,089.94
1989	45,044.89	20,717	(2)	20,717.00	24,327.89	6	4,054.65
1990	36,693.43	15,716	(2)	15,716.00	20,977.43	7	2,996.78
1991	24,443.91	9,668	(2)	9,668.00	14,775.91	8	1,846.99
1992	53,567.54	19,373	(2)	19,373.00	34,194.54	9	3,799.39

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 394.1 - Tools, Shop & Garage Equipment (Non-Unitized)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 18
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1993	10,028.74	3,277	(2)	3,277.00	6,751.74	10	675.17
1994	206,999.56	60,246	(2)	60,246.00	146,753.56	11	13,341.23
1995	9,864.87	2,510	(2)	2,510.00	7,354.87	12	612.91
1996	69,879.57	15,175	(2)	15,175.00	54,704.57	13	4,208.04
1997	66,862.98	11,978	(2)	11,978.00	54,884.98	14	3,920.36
1998	66,108.46	9,286	(2)	9,286.00	56,822.46	15	3,788.16
1999	60,557.07	6,125	(2)	6,125.00	54,432.07	16	3,402.00
2000	93,753.78	5,735	(2)	5,735.00	88,018.78	17	5,177.58
2001	88,425.17	1,818	(2)	1,818.00	86,607.17	18	4,811.51
	2,495,421.95	1,386,113		1,689,596.68	805,825.27	5.56%	138,677.00
Book Reserve				1,213,026.66			
Starting Point Depreciation Reserve				1,689,596.68			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				476,570.02	476,570.02	18	26,476.11
Total Amortization Amount						6.62%	165,153.11

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 394.2 - Tools, Shop & Garage Equipment (Unitized)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 18
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1962	6,990.28	6,990	(1)	6,990.28	0.00	0	0.00
1963	70,494.67	70,495	(1)	70,494.67	0.00	0	0.00
1964	2,415.75	2,416	(1)	2,415.75	0.00	0	0.00
1965	5,511.69	5,512	(1)	5,511.69	0.00	0	0.00
1966	7,731.14	7,516	(1)	7,731.14	0.00	0	0.00
1967	7,378.96	7,109	(1)	7,378.96	0.00	0	0.00
1968	231.79	220	(1)	231.79	0.00	0	0.00
1969	399.89	372	(1)	399.89	0.00	0	0.00
1970	7,827.19	7,157	(1)	7,827.19	0.00	0	0.00
1971	15,509.28	13,930	(1)	15,509.28	0.00	0	0.00
1972	10,484.48	9,241	(1)	10,484.48	0.00	0	0.00
1973	4,954.02	4,280	(1)	4,954.02	0.00	0	0.00
1974	4,004.35	3,387	(1)	4,004.35	0.00	0	0.00
1975	5,920.17	4,896	(1)	5,920.17	0.00	0	0.00
1976	998.41	806	(1)	998.41	0.00	0	0.00
1977	1,027.64	809	(1)	1,027.64	0.00	0	0.00
1978	2,122.39	1,625	(1)	2,122.39	0.00	0	0.00
1979	4,411.03	3,280	(1)	4,411.03	0.00	0	0.00
1980	3,423.85	2,467	(1)	3,423.85	0.00	0	0.00
1981	12,514.37	8,718	(1)	12,514.37	0.00	0	0.00
1982	7,684.76	5,162	(1)	7,684.76	0.00	0	0.00
1983	11,708.73	7,561	(1)	11,708.73	0.00	0	0.00
1984	1,854.49	1,148	(2)	1,148.00	706.49	1	706.49
1985	12,563.97	7,423	(2)	7,423.00	5,140.97	2	2,570.49
1986	6,836.77	3,840	(2)	3,840.00	2,996.77	3	998.92
1987	7,476.49	3,974	(2)	3,974.00	3,502.49	4	875.62
1988	12,360.85	6,184	(2)	6,184.00	6,176.85	5	1,235.37
1989	4,744.93	2,222	(2)	2,222.00	2,522.93	6	420.49
1990	2,357.99	1,025	(2)	1,025.00	1,332.99	7	190.43
1991	10,567.32	4,230	(2)	4,230.00	6,337.32	8	792.17
1992	9,564.80	3,493	(2)	3,493.00	6,071.80	9	674.64
1993	11,753.78	3,869	(2)	3,869.00	7,884.78	10	788.48
1994	12,528.52	3,664	(2)	3,664.00	8,864.52	11	805.87
1995	1,060.27	271	(2)	271.00	789.27	12	65.77
1996	7,303.76	1,588	(2)	1,588.00	5,715.76	13	439.67
1997	1,590.72	285	(2)	285.00	1,305.72	14	93.27
1998	431.11	61	(2)	61.00	370.11	15	24.67
2000	3,069.32	188	(2)	188.00	2,881.32	17	169.49
2001	0.00	0	(2)	0.00	0.00		
	299,809.93	217,414		237,209.84	62,600.09	3.62%	10,851.83
Book Rese				302,930.33			
Starting Point Depreciation Reserve				237,209.84			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-65,720.49	-65,720.49	18	-3,651.14
Total Amortization Amount						2.40%	7,200.70

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 394.3 - Vehicle Maintainence Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1987	5,304.03	3,368	(2)	3,368.00	1,936.03	6	322.67
1988	0.00	0	(2)	0.00	0.00	7	0.00
1989	3,393.19	1,906	(2)	1,906.00	1,487.19	8	185.90
1990	0.00	0	(2)	0.00	0.00	9	0.00
1991	8,613.81	4,157	(2)	4,157.00	4,456.81	10	445.68
1992	261.32	115	(2)	115.00	146.32	11	13.30
1993	1,728.56	689	(2)	689.00	1,039.56	12	86.63
1994	11,875.67	4,212	(2)	4,212.00	7,663.67	13	589.51
1995	0.00	0	(2)	0.00	0.00	14	0.00
1996	0.00	0.00	(2)	0.00	0.00	15	0.00
1997	0.00	0	(2)	0.00	0.00	16	0.00
1998	0.00	0	(2)	0.00	0.00	17	0.00
1999	0.00	0	(2)	0.00	0.00	18	0.00
2000	0.00	0	(2)	0.00	0.00	19	0.00
2001	0.00	0	(2)	0.00	0.00	20	0.00
	31,176.58	14,447		14,447.00	16,729.58	5.27%	1,643.70
Book Rese				11,255.54			
Starting Point Depreciation Reserve				14,447.00			
Book/Amortization Starting Point Depr Reserve Varia				3,191.46	3,191.46	20	159.57
(Amortize over Amortization Period)							
Total Amortization Amount						5.78%	1,803.27

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 394.4 - Vehicle Refueling Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1986	168,496.74	136,870	(1)	168,496.74	0.00	0	0.00
1987	0.00	0	(2)	0.00	0.00	1	0.00
1988	6,891.99	5,141	(2)	5,141.00	1,750.99	2	875.50
1989	0.00	0	(2)	0.00	0.00	3	0.00
1990	0.00	0	(2)	0.00	0.00	4	0.00
1991	123,192.75	76,026	(2)	76,026.00	47,166.75	5	9,433.35
1992	2,120.12	1,204	(2)	1,204.00	916.12	6	152.69
1993	2,061.06	1,064	(2)	1,064.00	997.06	7	142.44
1994	10,966.22	5,066	(2)	5,066.00	5,900.22	8	737.53
1995	547.21	222	(2)	222.00	325.21	9	36.13
1996	47,065.32	16,343	(2)	16,343.00	30,722.32	10	3,072.23
1997	2.59	1	(2)	1.00	1.59	11	0.14
1998	0.00	0	(2)	0.00	0.00	12	0.00
1999	0.00	0	(2)	0.00	0.00	13	0.00
2000	0.00	0	(2)	0.00	0.00	14	0.00
2001	0.00	0	(2)	0.00	0.00	15	0.00
	361,344.00	241,937		273,563.74	87,780.26	4.00%	14,450.01
Book Rese				234,336.79			
Starting Point Depreciation Reserve				273,563.74			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				39,226.95	39,226.95	15	2,615.13
Total Amortization Amount						4.72%	17,065.14

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 395 - Laboratory Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1917	248.19	248	(1)	248.19	0.00	0	0.00
1918	254.40	254	(1)	254.40	0.00	0	0.00
1919	260.76	261	(1)	260.76	0.00	0	0.00
1920	267.28	267	(1)	267.28	0.00	0	0.00
1921	273.96	274	(1)	273.96	0.00	0	0.00
1922	280.81	281	(1)	280.81	0.00	0	0.00
1923	287.83	288	(1)	287.83	0.00	0	0.00
1924	295.03	295	(1)	295.03	0.00	0	0.00
1925	302.41	302	(1)	302.41	0.00	0	0.00
1926	309.97	310	(1)	309.97	0.00	0	0.00
1927	317.72	318	(1)	317.72	0.00	0	0.00
1928	325.66	326	(1)	325.66	0.00	0	0.00
1929	333.80	334	(1)	333.80	0.00	0	0.00
1930	342.15	342	(1)	342.15	0.00	0	0.00
1931	350.70	351	(1)	350.70	0.00	0	0.00
1932	359.47	359	(1)	359.47	0.00	0	0.00
1933	368.45	368	(1)	368.45	0.00	0	0.00
1934	377.66	378	(1)	377.66	0.00	0	0.00
1935	387.11	387	(1)	387.11	0.00	0	0.00
1936	396.79	397	(1)	396.79	0.00	0	0.00
1937	406.71	407	(1)	406.71	0.00	0	0.00
1938	416.87	417	(1)	416.87	0.00	0	0.00
1939	427.29	427	(1)	427.29	0.00	0	0.00
1940	437.98	438	(1)	437.98	0.00	0	0.00
1941		0	(1)	0.00	0.00	0	0.00
1942		0	(1)	0.00	0.00	0	0.00
1943		0	(1)	0.00	0.00	0	0.00
1944		0	(1)	0.00	0.00	0	0.00
1945		0	(1)	0.00	0.00	0	0.00
1946	437.98	438	(1)	437.98	0.00	0	0.00
1947	437.98	438	(1)	437.98	0.00	0	0.00
1948	437.98	438	(1)	437.98	0.00	0	0.00
1949	1.89	2	(1)	1.89	0.00	0	0.00
1950	2,564.04	2,564	(1)	2,564.04	0.00	0	0.00
1951	1,039.70	1,040	(1)	1,039.70	0.00	0	0.00
1952	805.50	806	(1)	805.50	0.00	0	0.00
1953	902.82	903	(1)	902.82	0.00	0	0.00
1954	553.05	553	(1)	553.05	0.00	0	0.00
1955	4,836.21	4,836	(1)	4,836.21	0.00	0	0.00
1956	8,088.70	8,089	(1)	8,088.70	0.00	0	0.00
1957	1,095.26	1,095	(1)	1,095.26	0.00	0	0.00
1958	1,522.91	1,523	(1)	1,522.91	0.00	0	0.00
1959	1,655.38	1,655	(1)	1,655.38	0.00	0	0.00
1960	1,919.08	1,919	(1)	1,919.08	0.00	0	0.00
1961	842.89	843	(1)	842.89	0.00	0	0.00
1962	2,970.42	2,970	(1)	2,970.42	0.00	0	0.00
1963	3,206.92	3,207	(1)	3,206.92	0.00	0	0.00
1964	3,565.69	3,566	(1)	3,565.69	0.00	0	0.00
1965	8,297.31	8,090	(1)	8,297.31	0.00	0	0.00
1966	1,670.45	1,624	(1)	1,670.45	0.00	0	0.00
1967	2,548.34	2,449	(1)	2,548.34	0.00	0	0.00
1968	6,293.85	5,973	(1)	6,293.85	0.00	0	0.00
1969	7,085.19	6,627	(1)	7,085.19	0.00	0	0.00
1970	5,535.63	5,102	(1)	5,535.63	0.00	0	0.00
1971	232.62	211	(1)	232.62	0.00	0	0.00

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 395 - Laboratory Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1972	412.89	369	(1)	412.89	0.00	0	0.00
1973	500.58	440	(1)	500.58	0.00	0	0.00
1974	619.36	535	(1)	619.36	0.00	0	0.00
1975	894.69	759	(1)	894.69	0.00	0	0.00
1976	175.42	146	(1)	175.42	0.00	0	0.00
1977	870.65	710	(1)	870.65	0.00	0	0.00
1978	872.35	695	(1)	872.35	0.00	0	0.00
1979	199.29	155	(1)	199.29	0.00	0	0.00
1980	26,430.61	20,006	(1)	26,430.61	0.00	0	0.00
1981	3,784.36	2,780	(1)	3,784.36	0.00	0	0.00
1982	15,487.05	11,011	(2)	11,011.00	4,476.05	1	4,476.05
1983	14,023.78	9,617	(2)	9,617.00	4,406.78	2	2,203.39
1984	2,706.78	1,784	(2)	1,784.00	922.78	3	307.59
1985	17,869.81	11,273	(2)	11,273.00	6,596.81	4	1,649.20
1987	17,045.88	9,721	(2)	9,721.00	7,324.88	6	1,220.81
1988	1,235.97	665	(2)	665.00	570.97	7	81.57
1989	1,656.98	836	(2)	836.00	820.98	8	102.62
1990	522.68	245	(2)	245.00	277.68	9	30.85
1991	14,199.27	6,160	(2)	6,160.00	8,039.27	10	803.93
1992	1,179.16	468	(2)	468.00	711.16	11	64.65
1993	21,838.03	7,835	(2)	7,835.00	14,003.03	12	1,166.92
1994	2,203.93	705	(2)	705.00	1,498.93	13	115.30
1995	20,858.40	5,836	(2)	5,836.00	15,022.40	14	1,073.03
1996	1,164.44	278	(2)	278.00	886.44	15	59.10
1997	0.00	0	(2)	0.00	0.00	16	0.00
1998	0.00	0	(2)	0.00	0.00	17	0.00
1999	0.00	0	(2)	0.00	0.00	18	0.00
2000	22,599.05	1,521	(2)	1,521.00	21,078.05	19	1,109.37
2001	5,104.87	115	(2)	115.00	4,989.87	20	249.49
	271,033.07	169,655		179,406.99	91,626.08	5.43%	14,713.88
Book Reserve				57,665.05			
Starting Point Depreciation Reserve				179,406.99			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				121,741.94	121,741.94	20	6,087.10
Total Amortization Amount						7.67%	20,800.98

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 397.1 - Radio Communication Equipment (Fixed)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1991	283,409.44	174,901	(2)	174,901.00	108,508.44	5	21,701.69
1992	71,130.42	40,396	(2)	40,396.00	30,734.42	6	5,122.40
1993	23,122.18	11,934	(2)	11,934.00	11,188.18	7	1,598.31
1994	10,283.52	4,751	(2)	4,751.00	5,532.52	8	691.57
1995	36,113.02	14,648	(2)	14,648.00	21,465.02	9	2,385.00
1996	19,525.74	6,780	(2)	6,780.00	12,745.74	10	1,274.57
1997	17,886.14	5,134	(2)	5,134.00	12,752.14	11	1,159.29
1998	1,719.80	387	(2)	387.00	1,332.80	12	111.07
1999	0.00	0	(2)	0.00	0.00	13	0.00
2000	0.00	0	(2)	0.00	0.00	14	0.00
2001	18,464.91	605	(2)	605.00	17,859.91	15	1,190.66
	481,655.17	259,536		259,536.00	222,119.17	7.32%	35,234.56
Book Reserve				255,394.36			
Starting Point Depreciation Reserve				259,536.00			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				4,141.64	4,141.64	15	276.11
Total Amortization Amount						7.37%	35,510.67

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 397.2 - Radio Communication Equipment (Mobile)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1992	275,814.98	156,639	(2)	156,639.00	119,175.98	6	19,862.66
1993	14,099.41	7,277	(2)	7,277.00	6,822.41	7	974.63
1994	14,961.40	6,912	(2)	6,912.00	8,049.40	8	1,006.18
1995	18,861.62	7,650	(2)	7,650.00	11,211.62	9	1,245.74
1996	11,115.37	3,860	(2)	3,860.00	7,255.37	10	725.54
1997	7,034.48	2,019	(2)	2,019.00	5,015.48	11	455.95
1998	2,166.65	488	(2)	488.00	1,678.65	12	139.89
1999	0.00	0	(2)	0.00	0.00	13	0.00
2000	57,474.34	5,623	(2)	5,623.00	51,851.34	14	3,703.67
2001	0.00	0	(2)	0.00	0.00	15	0.00
	401,528.25	190,468		190,468.00	211,060.25	7.00%	28,114.25
Book Reserve				170,152.35			
Starting Point Depreciation Reserve				190,468.00			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				20,315.65	20,315.65	15	1,354.38
Total Amortization Amount						7.34%	29,468.62

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 397.3 - General Telephone Communication Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 10
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1962	10,198.28	10,198	(1)	10,198.28	0.00	0	0.00
1963	0.00	0	(1)	0.00	0.00	0	0.00
1964	0.00	0	(1)	0.00	0.00	0	0.00
1965	0.00	0	(1)	0.00	0.00	0	0.00
1966	52.39	52	(1)	52.39	0.00	0	0.00
1967	0.00	0	(1)	0.00	0.00	0	0.00
1968	0.00	0	(1)	0.00	0.00	0	0.00
1969	23.80	24	(1)	23.80	0.00	0	0.00
1970	0.00	0	(1)	0.00	0.00	0	0.00
1971	3,948.33	3,948	(1)	3,948.33	0.00	0	0.00
1972	415.51	416	(1)	415.51	0.00	0	0.00
1973	0.00	0	(1)	0.00	0.00	0	0.00
1974	0.00	0	(1)	0.00	0.00	0	0.00
1975	1,189.52	1,190	(1)	1,189.52	0.00	0	0.00
1976	0.00	0	(1)	0.00	0.00	0	0.00
1977	0.00	0	(1)	0.00	0.00	0	0.00
1978	768.91	769	(1)	768.91	0.00	0	0.00
1979	0.00	0	(1)	0.00	0.00	0	0.00
1980	0.00	0	(1)	0.00	0.00	0	0.00
1981	71.37	71	(1)	71.37	0.00	0	0.00
1982	433.48	412	(1)	433.48	0.00	0	0.00
1983	2,183.65	2,044	(1)	2,183.65	0.00	0	0.00
1984	10,228.48	9,301	(1)	10,228.48	0.00	0	0.00
1985	10,278.46	9,058	(1)	10,278.46	0.00	0	0.00
1986	1,982.55	1,686	(1)	1,982.55	0.00	0	0.00
1987	5,038.22	4,118	(1)	5,038.22	0.00	0	0.00
1988	7,206.19	5,629	(1)	7,206.19	0.00	0	0.00
1989	2,283.76	1,695	(1)	2,283.76	0.00	0	0.00
1990	2,063.91	1,446	(1)	2,063.91	0.00	0	0.00
1991	524.46	344	(1)	524.46	0.00	0	0.00
1992	3,159.48	1,918	(2)	1,918.00	1,241.48	1	1,241.48
1993	2,658.67	1,476	(2)	1,476.00	1,182.67	2	591.34
1994	979.46	490	(2)	490.00	489.46	3	163.15
1995	12,575.53	5,546	(2)	5,546.00	7,029.53	4	1,757.38
1996	6,166.38	2,337	(2)	2,337.00	3,829.38	5	765.88
1997	3,155.57	992	(2)	992.00	2,163.57	6	360.60
1998	236.42	59	(2)	59.00	177.42	7	25.35
1999	2,436.85	436	(2)	436.00	2,000.85	8	250.11
2000	258.23	28	(2)	28.00	230.23	9	25.58
2001	0.00	0	(2)	0.00	0.00	10	0.00
	90,517.86	65,683		72,173.27	18,344.59	5.72%	5,180.85
Book Reserve				34,571.00			
Starting Point Depreciation Reserve				72,173.27			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				37,602.27	37,602.27	10	3,760.23
Total Amortization Amount						9.88%	8,941.08

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 397.5 - Supervisory & Telemetering Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 10
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1962	863.27	863	(1)	863.27	0.00	0	
1963		0	(1)	0.00	0.00	0	
1964		0	(1)	0.00	0.00	0	
1965	2,642.62	2,643	(1)	2,642.62	0.00	0	0.00
1966	11,891.31	11,891	(1)	11,891.31	0.00	0	0.00
1967	4,291.05	4,291	(1)	4,291.05	0.00	0	0.00
1968	29,863.13	29,863	(1)	29,863.13	0.00	0	0.00
1969	8,557.59	8,558	(1)	8,557.59	0.00	0	0.00
1970	11,454.18	11,454	(1)	11,454.18	0.00	0	0.00
1971	3,626.38	3,445	(1)	3,626.38	0.00	0	0.00
1972	682.29	641	(1)	682.29	0.00	0	0.00
1973	1,033.02	959	(1)	1,033.02	0.00	0	0.00
1974	1,108.55	1,013	(1)	1,108.55	0.00	0	0.00
1975	1,736.12	1,561	(1)	1,736.12	0.00	0	0.00
1976	180.57	159	(1)	180.57	0.00	0	0.00
1977	0.00	0	(1)	0.00	0.00	0	0.00
1978	165.31	140	(1)	165.31	0.00	0	0.00
1979	2,889.31	2,400	(1)	2,889.31	0.00	0	0.00
1980	2,034.47	1,651	(1)	2,034.47	0.00	0	0.00
1981	2,791.32	2,211	(1)	2,791.32	0.00	0	0.00
1982	3,535.81	2,729	(1)	3,535.81	0.00	0	0.00
1983	19,276.85	14,473	(1)	19,276.85	0.00	0	0.00
1984	3,943.41	2,874	(1)	3,943.41	0.00	0	0.00
1985	0.00	0	(1)	0.00	0.00	0	0.00
1986	0.00	0	(1)	0.00	0.00	0	0.00
1987	2,698.10	1,774	(1)	2,698.10	0.00	0	0.00
1988	4,097.32	2,588	(1)	4,097.32	0.00	0	0.00
1989	0.00	0	(1)	0.00	0.00	0	0.00
1990	3,680.20	2,120	(1)	3,680.20	0.00	0	0.00
1991	1.07	1	(1)	1.07	0.00	0	0.00
1992	666.97	343	(2)	343.00	323.97	1	323.97
1993	56.96	27	(2)	27.00	29.96	2	14.98
1994	189.71	85	(2)	85.00	104.71	3	34.90
1995	210.27	86	(2)	86.00	124.27	4	31.07
1996	0.00	0	(2)	0.00	0.00	5	0.00
1997	0.00	0	(2)	0.00	0.00	6	0.00
1998	0.00	0	(2)	0.00	0.00	7	0.00
1999	0.00	0	(2)	0.00	0.00	8	0.00
2000	0.00	0	(2)	0.00	0.00	9	0.00
2001	0.00	0	(2)	0.00	0.00	10	0.00
	124,167.16	110,843		122,720.98	582.91	0.33%	404.92
Book Reserve				123,660.97			
Starting Point Depreciation Reserve				122,720.98			
Book/Amortization Starting Point Depr Reserve Varianc				-939.99	-939.99	10	-94.00
(Amortize over Amortization Period)							
Total Amortization Amount						0.25%	310.92

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 397.6 - SCADA Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 8
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1982	20,454.51	20,455	(1)	20,454.51	0.00	0	0.00
1983	272.42	272	(1)	272.42	0.00	0	0.00
1984	0.00	0	(1)	0.00	0.00	0	0.00
1985	0.00	0	(1)	0.00	0.00	0	0.00
1986	0.00	0	(1)	0.00	0.00	0	0.00
1987	0.00	0	(1)	0.00	0.00	0	0.00
1988	9,732.20	9,732	(1)	9,732.20	0.00	0	0.00
1989	0.00	0	(1)	0.00	0.00	0	0.00
1990	0.00	0	(1)	0.00	0.00	0	0.00
1991	7.00	6	(1)	7.00	0.00	0	0.00
1992	424.05	366	(1)	424.05	0.00	0	0.00
1993	4.17	3	(1)	4.17	0.00	0	0.00
1994	0.00	0	(2)	0.00	0.00	1	0.00
1995	0.00	0	(2)	0.00	0.00	2	0.00
1996	0.00	0	(2)	0.00	0.00	3	0.00
1997	0.00	0	(2)	0.00	0.00	4	0.00
1998	0.00	0	(2)	0.00	0.00	5	0.00
1999	0.00	0	(2)	0.00	0.00	6	0.00
2000	0.00	0	(2)	0.00	0.00	7	0.00
2001	0.00	0	(2)	0.00	0.00	8	0.00
	30,894.35	30,834		30,894.35	0.00	0.00%	0.00
Book Reserve				30,894.36			
Starting Point Depreciation Reserve				30,894.35			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-0.01	-0.01	8	0.00
Total Amortization Amount						0.00%	0.00

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 397.8 - Network Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 5
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1997	20,086.86	14,881	(2)	14,881.00	5,205.86	1	5,205.86
1998	71.16	44	(2)	44.00	27.16	2	13.58
1999	0.00	0	(2)	0.00	0.00	3	0.00
2000	2,960.82	849	(2)	849.00	2,111.82	4	527.96
2001	7,218.71	706	(2)	706.00	6,512.71	5	1,302.54
	30,337.55	16,480		16,480.00	13,857.55	23.24%	7,049.94
Book Reserve				11,889.89			
Starting Point Depreciation Reserve				16,480.00			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				4,590.11	4,590.11	5	918.02
Total Amortization Amount						26.26%	7,967.96

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 398.00 - Miscellaneous Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Propert

Average Service Life-Amortiztion (Years): 20
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1919	1,799.43	1,799	(1)	1,799.43	0.00	0	0.00
1920	1,844.42	1,844	(1)	1,844.42	0.00	0	0.00
1921	1,890.54	1,891	(1)	1,890.54	0.00	0	0.00
1922	1,937.81	1,938	(1)	1,937.81	0.00	0	0.00
1923	1,986.26	1,986	(1)	1,986.26	0.00	0	0.00
1924	2,035.91	2,036	(1)	2,035.91	0.00	0	0.00
1925	2,086.81	2,087	(1)	2,086.81	0.00	0	0.00
1926	2,138.98	2,139	(1)	2,138.98	0.00	0	0.00
1927	2,192.46	2,192	(1)	2,192.46	0.00	0	0.00
1928	2,247.27	2,247	(1)	2,247.27	0.00	0	0.00
1929	2,303.46	2,303	(1)	2,303.46	0.00	0	0.00
1930	2,361.04	2,361	(1)	2,361.04	0.00	0	0.00
1931	2,420.07	2,420	(1)	2,420.07	0.00	0	0.00
1932	2,480.57	2,481	(1)	2,480.57	0.00	0	0.00
1933	2,542.58	2,543	(1)	2,542.58	0.00	0	0.00
1934	2,606.15	2,606	(1)	2,606.15	0.00	0	0.00
1935	2,671.31	2,671	(1)	2,671.31	0.00	0	0.00
1936	2,738.09	2,738	(1)	2,738.09	0.00	0	0.00
1937	2,806.55	2,807	(1)	2,806.55	0.00	0	0.00
1938	2,670.74	2,671	(1)	2,670.74	0.00	0	0.00
1939	1,504.70	1,505	(1)	1,504.70	0.00	0	0.00
1940	1,578.42	1,578	(1)	1,578.42	0.00	0	0.00
1941	0.00	0	(1)	0.00	0.00	0	0.00
1942	0.00	0	(1)	0.00	0.00	0	0.00
1943	0.00	0	(1)	0.00	0.00	0	0.00
1944	0.00	0	(1)	0.00	0.00	0	0.00
1945	0.00	0	(1)	0.00	0.00	0	0.00
1946	1,578.42	1,578	(1)	1,578.42	0.00	0	0.00
1947	1,578.42	1,578	(1)	1,578.42	0.00	0	0.00
1948	75.51	76	(1)	75.51	0.00	0	0.00
1949	712.06	712	(1)	712.06	0.00	0	0.00
1950	18.87	19	(1)	18.87	0.00	0	0.00
1951	1,511.40	1,511	(1)	1,511.40	0.00	0	0.00
1952	983.55	984	(1)	983.55	0.00	0	0.00
1953	293.80	294	(1)	293.80	0.00	0	0.00
1954	927.89	928	(1)	927.89	0.00	0	0.00
1955	1,525.46	1,525	(1)	1,525.46	0.00	0	0.00
1956	3,052.88	3,053	(1)	3,052.88	0.00	0	0.00
1957	1,217.33	1,217	(1)	1,217.33	0.00	0	0.00
1958	377.32	377	(1)	377.32	0.00	0	0.00
1959	169.89	170	(1)	169.89	0.00	0	0.00
1960	496.66	497	(1)	496.66	0.00	0	0.00
1961	59.51	60	(1)	59.51	0.00	0	0.00
1962	520.05	520	(1)	520.05	0.00	0	0.00
1963	426.66	427	(1)	426.66	0.00	0	0.00
1964	942.69	943	(1)	942.69	0.00	0	0.00
1965	1,709.06	1,666	(1)	1,709.06	0.00	0	0.00
1966	78.17	76	(1)	78.17	0.00	0	0.00
1967	3,942.75	3,789	(1)	3,942.75	0.00	0	0.00
1968	271.95	258	(1)	271.95	0.00	0	0.00
1969	189.56	177	(1)	189.56	0.00	0	0.00
1970	1,608.17	1,482	(1)	1,608.17	0.00	0	0.00
1971	3,776.19	3,426	(1)	3,776.19	0.00	0	0.00
1972	7,021.13	6,270	(1)	7,021.13	0.00	0	0.00

Table 5

Montana-Dakota Utilities Company
Gas Division
Account 398.00 - Miscellaneous Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1973	1,865.72	1,639	(1)	1,865.72	0.00	0	0.00
1974	2,021.54	1,746	(1)	2,021.54	0.00	0	0.00
1975	642.76	545	(1)	642.76	0.00	0	0.00
1976	526.83	438	(1)	526.83	0.00	0	0.00
1977	4,506.09	3,674	(1)	4,506.09	0.00	0	0.00
1978	3,546.17	2,827	(1)	3,546.17	0.00	0	0.00
1979	1,977.23	1,538	(1)	1,977.23	0.00	0	0.00
1980	1,401.81	1,061	(1)	1,401.81	0.00	0	0.00
1981	1,047.93	770	(1)	1,047.93	0.00	0	0.00
1982	517.45	368	(2)	368.00	149.45	1	149.45
1983	2,336.29	1,602	(2)	1,602.00	734.29	2	367.15
1984	940.17	620	(2)	620.00	320.17	3	106.72
1985	1,072.89	677	(2)	677.00	395.89	4	98.97
1986	150.93	91	(2)	91.00	59.93	5	11.99
1988	259.43	140	(2)	140.00	119.43	7	17.06
1989	512.29	258	(2)	258.00	254.29	8	31.79
1990	1,079.95	507	(2)	507.00	572.95	9	63.66
1991	2,406.18	1,044	(2)	1,044.00	1,362.18	10	136.22
1992	3,002.27	1,191	(2)	1,191.00	1,811.27	11	164.66
1993	2,104.05	755	(2)	755.00	1,349.05	12	112.42
1994	20,986.12	6,710	(2)	6,710.00	14,276.12	13	1,098.16
1995	0.00	0	(2)	0.00	0.00	14	0.00
1996	2,257.88	539	(2)	539.00	1,718.88	15	114.59
1997	1,968.54	388	(2)	388.00	1,580.54	16	98.78
1998	2,379.33	368	(2)	368.00	2,011.33	17	118.31
1999	0.00	0	(2)	0.00	0.00	18	0.00
2000	493.66	33	(2)	33.00	460.66	19	24.25
2001	1,357.13	31	(2)	31.00	1,326.13	20	66.31
	145,269.56	112,016		51,455.06	28,502.56	1.91%	2,780.49
Book Reserve				70,042.49			
Starting Point Depreciation Reserve				51,455.06			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-18,587.43	-18,587.43	20	-929.37
Total Amortization Amount						1.27%	1,851.12

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

MONTANA-DAKOTA UTILITIES COMPANY

Gas Division

General

This report sets forth the results of our study of the depreciable property of the Montana-Dakota Utilities Company (the Company) as of December 31, 2001 and contains the basic parameters (recommended average service lives and life characteristics) for the proposed average remaining life depreciation rates until a subsequent service life study is completed. All average service lives set forth in this report are developed based upon plant in service as of December 31, 2001.

The scope of the study included an analysis of Company historical data through December 31, 2001, discussions with Company management staff to identify prior and prospective factors affecting the Company's plant in service, as well as interpretation of past service life data experience and future life expectancies to determine the appropriate average service lives of the Company's surviving plant. The service lives and life characteristics, resulting from the in-depth study, were utilized together with the Company's plant in service and book depreciation reserve to determine the recommended Average Remaining Life (ARL) depreciation rates related to the Company's plant in service as of December 31, 2001.

In preparing the study, the Company's historical investment data were studied using various service life analysis techniques. Further, discussions were held with the Company's management to obtain an overview of the Company's facilities and to discuss the general scope of operations together with other factors which could have a bearing on the service lives of the Company's property. Finally, the study results were tempered by information gathered during plant inspection tours of a representative portion of the Company's property.

The Company maintains a property record containing a summary of its fixed capital investments by property account. This investment data was analyzed and summarized by property group and/or sub group and vintage then utilized as a basis for the various

depreciation calculations.

Depreciation Study Overview

There are numerous methods utilized to recover property investment depending upon the goal. For example, accelerated methods such as double declining balance and sum of years digits are methods used in tax accounting to motivate additional investments. Broad Group (BG) and Equal Life Group (ELG) are both Straight Line Grouping Procedures recognized and utilized by various regulatory jurisdictions depending upon the policy of the specific agency.

The Straight Line (Group) Method of depreciation utilized in this study to develop the recommended depreciation rates is the Broad Group Procedure together with the Average Remaining Life Technique. The use of this procedure and technique is based upon recovering the net book cost (original cost less book reserve) of the surviving plant in service over its estimated remaining useful life. Any variance between the book reserve and an implied theoretical calculated reserve is compensated for under this procedure. That is, as the Company's book reserve increases above or declines below the theoretical reserve at a specific point in time, the Company's average remaining life depreciation rate in subsequent years will be increased or decreased to compensate for the variance, thereby, assuring full recovery of the Company's investment by the end of the property's life.

The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The annual depreciation amount to be utilized is based upon the remaining productive life over which the undepreciated capital investment needs to be recovered. The determination of the productive remaining life for each property group usually includes an in-depth study of past experience in addition to estimates of future expectations.

Annual Depreciation Accrual

Through the utilization of the Average Remaining Life Technique, the Company will

recover the undepreciated fixed capital investment in the appropriate amounts as annual depreciation expense in each year throughout the remaining life of the property. The procedure incorporates the future life expectancy of the property, the vintaged surviving plant in service, and estimated net salvage, together with the book depreciation reserve balance to develop the annual depreciation rate for each property account. Accordingly, the ARL technique meets the objective of providing a straight line recovery of the undepreciated fixed capital property investment.

As indicated, the use of the Average Remaining Life Technique results in charging the appropriate annual depreciation amounts over the remaining life of the property to insure full recovery by end of life. That does not mean that once an average remaining life is estimated, it can not be changed at any point throughout the service life, but that the annual expense is calculated on a Straight Line Method rather than by the previously mentioned, "sum of the years digits" or "double declining balance" methods, etc. The "group" refers to the method of calculating annual depreciation on the summation of the investment in any one depreciable group or plant account rather than calculating depreciation for each individual unit.

Under Broad Group depreciation some units may be over depreciated and other units may be under depreciated at the time when they are retired from service, but overall, the account is fully depreciated when average service life is attained. By comparison, Equal Life Group depreciation rates are designed to fully accrue the cost of the asset group by the time of retirement. For both the Broad Group and Equal Life Group Procedures the full cost of the investment is credited to plant in service when the retirement occurs and likewise the depreciation reserve is debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption the retired property was at average service life.

Group Depreciation Procedures

Group depreciation procedures are utilized to depreciate property when more than one

item of property is being depreciated. Such a procedure is appropriate because all of the items within a specific group typically do not have identical service lives, but have lives which are dispersed over a range of time. Utilizing a group depreciation procedure allows for a condensed application of depreciation rates to groups of similar property in lieu of extensive depreciation calculations on an item by item basis. The two more common group depreciation procedures are the Broad Group (BG) and Equal Life Group (ELG) approach.

In developing depreciation rates using the Broad Group procedure, the annual depreciation rate is based on the average of the overall group, which is then applied to the group's surviving original cost investment. A characteristic of this procedure is that retirements of individual units occurring prior to average service life will be under depreciated, while individual units retired after average service life will be over depreciated when removed from service, but overall, the group investment will achieve full recovery by the end of the life of the total property group. That is, the under recovery occurring early in the life of the account is balanced by the over recovery occurring subsequent to average service life. In summary, the cost of the investment is complete at the end of the property's life cycle, but the rate of recovery does not match the consumption pattern which was used to provide service to the company's customers.

Under the average service life procedure, the annual depreciation rate is calculated by the following formula:

$$\text{Annual Accrual Rate, Percent} = \frac{100\% - \text{Salvage}}{\text{Average Service Life}} \times 100$$

The application of the broad group procedure to life span groups results in each vintage investment having a different average service life. This circumstance exists because the concurrent retirement of all vintages at the anticipated retirement year results in truncating and, therefore, restricting the life of each successive years vintage investment. An average service life is calculated for each vintage investment in accordance with the above formula. Subsequently, a composite service life and depreciation rate is calculated relative to all vintages within the property group by weighting the life for each vintage by the

related surviving vintage investment within the group.

In the Equal Life Group, the property group is subdivided, through the use of plant life tables, into equal life groups. In each equal life group, portions of the overall property group includes that portion which experiences the life of the specific sub-group. The relative size of each sub-group is determined from the overall group life characteristic (property dispersion curve). This procedure both overcomes the disadvantage of voluminous record requirements of unit depreciation, as well as, eliminates the need to base depreciation on overall lives as required under the broad group procedure. The application of this procedure results in each sub-group of the property having a single life. In this procedure, the full cost of short lived units is accrued during their lives leaving no under accruals to be recovered by over accruals on long lived plant. The annual depreciation for the group is the summation of the depreciation accruals based on the service life of each Equal Life Group.

The ELG Procedure is superior to the BG Procedure because it allocates the capital cost of a group property to annual expense in accordance with the consumption of the property group providing service to customers. In this regard, the company's customers are more appropriately charged with the cost of the property consumed in providing them service during the applicable service period. The more timely return of plant cost is accomplished by fully accruing each unit's cost during its service life, thereby, not only reducing the risk of incomplete cost recovery, but also the procedure results in less return on rate base over the life of a depreciable group. The total depreciation expense is the same for all procedures which allocate the full capital cost to expense, but at any specific point in time, the depreciated original cost is less under the ELG procedure than under the BG procedure. This circumstance exists because under the equal life group procedure, the rate base is not maintained at a level of greater than the future service value of the surviving plant as is the case when using the average service life procedure. Consequently, the total return required from the ratepayers is less under the ELG procedure.

While the equal life group procedure has been known to depreciation experts for

many years widespread interest in applying the procedure developed only after high speed electronic computers became available to perform the large volume of arithmetic computations required in developing ELG based depreciation lives and rates. The table on the following page illustrates the procedure for calculating equal life group depreciation accrual rates and summarizes the results of the underlying calculations. Depreciation rates are determined for each age interval (one year increment) during the life of a group of property which was installed in a given year or vintage group. The age of the vintage group is shown in column (A) of the ELG table. The percent surviving at the beginning of each age interval is determined from the Iowa 10-R3 survivor curve which is set forth in column (B). The percent retired during each age interval, as shown in column (C), is the difference between the percent surviving at successive age intervals. Accordingly, the percentage amount of the vintage group retired defines the size of each equal life group. For example, during the interval 3 1/2 to 4 1/2, 1.93690 percent of the vintage group is retired at an average age of four years. In this case, the 1.93690 percent of the group experiences an equal life of four years. Likewise, 3.00339 percent is retired during the interval 4 1/2 to 5 1/2 and experiences a service life of five years. Further, 4.42969 percent experiences a six-year life; etc. Calculations are made for each age interval from the zero age interval through the end of the life of the vintage group. The average service life for each age interval's equal life group is shown in column (E) of the table.

The amount to be accrued annually for each equal life group is equal to the percentage retired in the equal life group divided by its service life. Inasmuch as additions and retirements are assumed, for calculation purposes, to occur at midyear only one-half of the equal life group's annual accrual is allocated to expense during its first and last years of service life. The accrual amount for the property retired during age interval 0 to 1/2 must be equal to the amount retired to insure full recovery of that component during that period. The accruals for each equal life group during the age intervals of the vintage group's life cycle are shown in column (F). The total accrual for a given year is the summation of the equal life

XYZ UTILITY COMPANY
CALCULATION OF ASL, ARL AND ACCRUED DEPRECIATION FACTORS
BASED UPON AN IOWA 10-R3 CURVE USING THE EQUAL LIFE GROUP (ELG) PROCEDURE

							EQUAL LIFE GROUP PROCEDURE			
AGE AT BEGIN OF INTERVAL	LIFE TABLE BEGIN OF INTERVAL	RETIREMENT DURING INTERVAL	AVERAGE SURVIVING	AGE OF AMOUNT RETIRED	AMOUNT FOR EACH LIFE GROUP	AMOUNT FOR REMAINING LIFE GROUPS	AVERAGE SERVICE LIFE	AVERAGE REMAINING LIFE	ELG/ARL DEPR RATE	ACCRUED DEPR RES FACTOR
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
0.0	1.0000000	0.0009198	0.9995401	0.25	0.0009198	0.0583036	8.57	8.57	11.67	0.0000000
0.5	0.9990802	0.0033314	0.9974145	1.0	0.0033314	0.1131019	8.82	8.32	11.34	0.0566975
1.5	0.9957488	0.0065393	0.9924792	2.0	0.0032697	0.1098013	9.04	7.54	11.06	0.1659501
2.5	0.9892095	0.0117037	0.9833577	3.0	0.0039012	0.1062159	9.26	6.76	10.80	0.2700337
3.5	0.9775058	0.0193690	0.9678213	4.0	0.0048422	0.1018442	9.50	6.00	10.52	0.3683062
4.5	0.9581368	0.0300339	0.9431199	5.0	0.0060068	0.0964196	9.78	5.28	10.22	0.4600565
5.5	0.9281029	0.0442969	0.9059545	6.0	0.0073828	0.0897248	10.10	4.60	9.90	0.5447146
6.5	0.8838060	0.0631367	0.8522377	7.0	0.0090195	0.0815237	10.45	3.95	9.57	0.6217794
7.5	0.8206693	0.0876232	0.7768577	8.0	0.0109529	0.0715375	10.86	3.36	9.21	0.6906424
8.5	0.7330461	0.1166879	0.6747022	9.0	0.0129653	0.0595783	11.32	2.82	8.83	0.7505770
9.5	0.6163582	0.1431836	0.5447664	10.0	0.0143184	0.0459365	11.86	2.36	8.43	0.8010714
10.5	0.4731746	0.1533568	0.3964962	11.0	0.0139415	0.0318066	12.47	1.97	8.02	0.8423003
11.5	0.3198178	0.1363216	0.2516570	12.0	0.0113601	0.0191557	13.14	1.64	7.61	0.8753616
12.5	0.1834962	0.0975199	0.1347363	13.0	0.0075015	0.0097249	13.85	1.35	7.22	0.9022159
13.5	0.0859763	0.0559043	0.0580242	14.0	0.0039932	0.0039775	14.59	1.09	6.85	0.9254232
14.5	0.0300720	0.0244398	0.0178521	15.0	0.0016293	0.0011663	15.31	0.81	6.53	0.9473077
15.5	0.0056322	0.0055324	0.0028660	16.0	0.0003458	0.0001788	16.03	0.53	6.24	0.9667657
16.5	0.0000998	0.0000998	0.0000499	17.0	0.0000059	0.0000029	17.00	0.50	5.88	0.9705882
17.5	0.0000000	0.0000000	0.0000000	18.0	0.0000000	0.0000000				
		1.0000000				1.0000000				

group accruals for that year. For example, the total accrual for the second year, as shown in column (G), is 11.31019 percent and is the sum of all succeeding years remaining equal life group accruals plus one half of the current years life group accrual listed in column (F). For the zero age interval year, the total accrual is equal to one half of the sum of all succeeding years remaining equal life accruals plus the amount for the zero interval equal life group accrual. The one half year accrual for the zero age interval is consistent with the half year convention relative to property during its installation year. The sum of the annual accruals for each age interval contained in column (G) total to 1.000 demonstrating that the developed rates will recover 100% of plant no more and no less. The annual accrual rate which will result in the accrual amount is the ratio of the accrual amount (11.31019 percent) to the average percent surviving during the interval, column (D), (99.74145 percent), which is a rate of 11.34% (column J). Column (J) contains a summary of the accrual rates for each age interval of the property groups life cycle based upon an Iowa 10-R3 survivor curve.

Remaining Life Technique

In the Average Remaining Life depreciation technique, the annual accrual is calculated according to the following formula where, (A) the annual depreciation for each group equals, (D) the depreciable cost of plant, less (U) the accumulated provision for depreciation, less (S) the estimated future net salvage, divided by (R) the composite remaining life of the group:

$$A = \frac{D - U - S}{R}$$

The annual accrual rate (a) is expressed as a percentage of the depreciable plant balance by dividing the equation by (D) the depreciable cost of plant times 100:

$$(a) = \frac{D - U - S}{R} \times \frac{1}{D} \times 100$$

As further indicated by the equation, the accumulated provision for depreciation by vintage is required in order to calculate the remaining life depreciation rate for each property group. In practice, most often such detail is not available; therefore, composite remaining

lives are determined for each depreciable group, i.e., property account.

The remaining life for a depreciable group is calculated by first determining the remaining life for each vintage year in which there is surviving investment. This is accomplished by solving the area under the survivor curve selected to represent the average life and life characteristic of the property account. The remaining life for each vintage is composited by dividing (D) the depreciable cost of each vintage, by (L) its average service life, and multiplying this ratio by its average remaining life (E). The composite remaining life of the group (R) equals the sums of products divided by the sum of the quotients:

$$R\ Group = \frac{\sum D/L \times E}{\sum D/L}$$

The functional level accumulated provision for depreciation, which was the basis for developing the composite average remaining life accrual and annual depreciation rate for each property account as per this report, was obtained from the Company's books and records. The functional level depreciation reserve was further allocated to each property account and sub-account based upon a detailed theoretical depreciation reserve as of December 31, 2001.

Salvage

Net salvage is the difference between gross salvage, or what is received when an asset is disposed of, and the cost of removing it from service. Salvage experience is normally included with the depreciation rate so that current accounting periods reflect a proportional share of the ultimate abandonment and removal cost or salvage received at the end of the property service life. Historical Net salvage analysis results are expressed as a percentage of the plant retired by dividing the dollars of net salvage incurred by the original cost of the plant retired. Net salvage is said to be positive if gross salvage exceeds the cost of removal, but if cost of removal exceeds gross salvage the result is then negative salvage.

The cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise removing plant and related transportation, handling, and overheads in connection with the work, as well as environmental clean up costs associated

with the property. Salvage includes proceeds received for the sale of plant and materials or the return of equipment to stores for reuse.

Net salvage experience is studied for a period of years to determine the trends which have occurred in the past. These trends are considered together with any changes that are anticipated in the future to determine the future net salvage factor for remaining life depreciation purposes. The goal of incorporating net salvage into the annual depreciation rate is to appropriately allocate the net cost of each asset group to each accounting period. The net cost of each asset group must include not only the original cost when placed in service, but also the net salvage, positive or negative, that will be incurred at end of live. The inclusion, in the net salvage amount, of all benefits received and/or costs incurred is premised on the concept that property ownership includes the responsibility of the proper disposal of the facilities at end of life. Therefore, if current customers benefit from the property's use, the customer should pay/receive a pro rata share of all costs incurred and/or receipts generated in the retirement, abandonment and/or removal of the assets.

The analysis of net salvage is routinely based upon identification of the individual components, (i.e. gross salvage and cost of removal) included in net salvage amount. This analysis identifies that the component items experience different trends over time. That is, as property continues to age, gross salvage routinely declines, while with the passage of time cost of removal tends to increase in conjunction with ever increasing labor rates. On an aggregate basis, most historical retirements from each property group, routinely occur at an average age that is less than the average service life of the account. Accordingly, the experienced historical salvage analysis, with regard to gross salvage, will most often be overstated relative to anticipated future gross salvage. By comparison, the historical analysis will typically be understated with regard to future cost of removal. That is, in general terms, it can be assumed that with the increased passage of time, any future positive net salvage will likely be lower, while future negative net salvage will likely be higher than the overall levels experienced in the past. Because of these future events, it is important that the overall

historical net salvage experience should only be used as a benchmark for estimating future net salvage, and that salvage trends as well as other future factors be considered in the process of estimating future net salvage. Otherwise, the future net salvage estimates will clearly understate the future net negative salvage and overstate any gross salvage that will occur in conjunction with future retirements.

Service Lives

Several factors contribute to the length of time or average service life which the property achieves. The three (3) major categories under which these factors fall are: (1) physical; (2) functional, and; (3) contingent casualties.

The physical category includes such things as deterioration, wear and tear and the action of the natural elements. The functional category includes inadequacy, obsolescence and requirements of governmental authorities. Obsolescence occurs when it is no longer economically feasible to use the property to provide service to customers or when technological advances have provided a substitute of superior performance. The remaining factor of contingent casualties relates to retirements caused by accidental damage or construction activity of one type or another.

In performing the life analysis for any property being studied, both past experience and future expectations must be considered in order to fully evaluate the circumstances which may have a bearing on the remaining life of the property. This ensures the selection of an average service life which best represents the expected life of each property investment.

Survivor Curves

The preparation of a depreciation study or theoretical depreciation reserve typically incorporates smooth curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves generally used are the family of curves developed at Iowa State University which are widely used and accepted throughout the utility industry.

The shape of the curves within the Iowa family are dependent upon whether the

maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if occurring at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right ®) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

Many times, actual Company data has not completed its life cycle, therefore, the survivor table generated from the Company data is not extended to zero percent surviving. This situation requires an estimate be made with regard to the remaining segment of the property group's life experience. Further, actual Company experience is often erratic, making its utilization for average service life estimating difficult. Accordingly, the Iowa curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Study Procedures

Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical retirements, current and future construction, historical experience and future expectations of salvage and cost of removal as related to plant investment. Service lives are affected by many different factors, some of which can be obtained from studying plant experience, others which may rely heavily on future expectations. When physical aspects are the controlling factor in determining the service life of property, historical experience is a valuable tool in selecting service lives. In the case where changing technology or a less costly alternative develops, then historical experience is of lesser value.

While various methods are available to study historical data, the principal methods utilized to determine average service lives for a Company's property are the Retirement Rate Method, the Simulated Plant Record Method, the Life Span Method, and the Judgement Method.

Retirement Rate Method - The Retirement Rate Method uses actual Company

retirement experience to develop a survivor curve (observed life table) which is used to determine the average service life being experienced in the account under study. Computer processing provides the opportunity to review various experience bands throughout the life of the account to observe trends and changes. For each experience band studied, the "observed life table" is constructed based on retirement experience within the band of years. In some cases, the total life of the account has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is this "stub curve" or total life curve, if achieved, which is matched or fitted to a standard Survivor curve. The matching process is performed both by computer analysis, using a least square technique, and by manually plotting observed life tables to which smooth curves are fitted. The fitted smooth curve provides the basis to determine the average service life of the property group under study.

Simulated Balances Method - In this method of analysis, simulated surviving balances are determined for each balance included in the test band by multiplying each year's original gross additions installed by the Company by the appropriate factor of each Standard Survivor Curve, summing the products, and comparing the results with the related year end plant balance to determine the "best fitting" curve and life within the test period. Various test bands are reviewed to determine trends or changes to indicated service lives in various bands of years. By definition, the curve with the "best fit" is the curve which produces simulated plant balances that most closely matches the actual plant balances as determined by the sum of the "least squares". The sum of the "least squares" is arrived at by starting with the difference between the simulated balances and the actual balance for a given year, squaring the difference, and the curve which produces the smallest sum (of squared difference) is judged to be the "best fit".

Period Retirements Method - The application of the Period Retirements Method is similar to the "Simulated Plant Balances" Method, except the procedure utilizes a Standard Survivor Curve and service life to simulate annual retirements instead of balances in performing the "least squares" fitting process during the test period. This procedure does

tend to experience wider fluctuations due to the greater variations in level of experienced retirements versus additions and balances thereby producing greater variation in the study results.

Life Span Method - The Life Span or Forecast Method is a method utilized to study various accounts in which the expected retirement dates of specific property or locations can be reasonably estimated. In the Life Span Method, an estimated probable retirement year is determined for each location of the property group. An example of this would be a structure account, in which the various segments of the account are "life spanned" to a probable retirement date which is determined after considering a number of factors, such as management plans, industry standards, the original construction date, subsequent additions, resultant average age and the current - as well as the overall - expected service life of the property being studied. If in the past the property has experienced interim retirements, these are studied to determine an interim retirement rate. Otherwise, interim retirement rate parameters are estimated for properties which are anticipated to experience such retirements. The selected interim service life parameters (Iowa curve and life) are then used with the vintage investment and probable retirement year of the property to determine the average remaining life as of the study date. No attempt is made to include any anticipated additions to the property subsequent to the study date. The recovery of such additions if made, is reflected when preparing subsequent depreciation studies.

Judgement Method - Standard quantitative methods such as the Retirement Rate Method, Simulated Plant Record Method, etc. are normally utilized to analyze a Company's available historical service life data. The results of the analysis together with information provided by management as well as judgement are utilized in estimating the prospective recommended average service lives. However, there are some circumstances where sufficient retirements have not occurred, or where prospective plans or guidelines are unavailable. In these circumstances, judgement alone is utilized to estimate service lives based upon service lives used by other utilities for this class of plant as well as what might

be reasonable life for this plant giving consideration to the current age and use of the facilities.

MONTANA - DAKOTA UTILITIES
Gas Division

Study Results

Account 374.20 - Rights of Way

The Company's investment in this account totals $89,641, and is presently being depreciated utilizing an annual depreciation rate of 2.58 percent. The investment's current average is 17.2 years.

Retirements totaling $1,754 have been experienced to date. Based upon a general analysis of the historical data an Iowa 65-R2.5 life and curve is estimated as the applicable service life parameters for this property group investment. Application of the recommended service life parameters to the Company's vintage investment produces an average remaining life of 49.3 years.

An analysis of the Company's historical experience relative to net salvage shows that this account has not experienced any net salvage and none is anticipated in the future. Accordingly, future net salvage is estimated at zero (0) percent and when combined together with the recommended service life parameters and Company's investment produces a recommended annual depreciation rate of .75 percent.

Account 375 - District Meas. & Regulator Station Structures

The Company's investment in this account totals $521,210, and is presently being depreciated utilizing an annual depreciation rate of 2.40 percent. The investment in the account is principally related to smaller metal structures utilized to house the Company's property at the various regulator sites. Company retirements totaling $131,348, were analyzed via the Simulated Analysis Method relative to the overall 1918-2001 experience band as well as numerous interim periods. In addition, an analysis of limited actuarial

retirement data identified that the Company's retirements have generally been occurring at an average age of 38 years. Based upon the historical analysis an Iowa 55-R2.5 life and curve is estimated for this property group. Application of the recommended service life parameters to the Company's current surviving investment produces an average remaining life 29.9 years.

The Company's historical retirement data was analyzed to identify the level of net salvage being experienced by this property. Net salvage has varied over the past thirty-four (34) year period but has averaging more than negative twenty-eight (28) percent during the 1968-2001 study period. During the more recent ten-fifteen year period net salvage has routinely occurred in the range of negative thirty (30) to more than negative one-hundred (100) percent net salvage. Based upon the available historical data and the anticipation that current salvage will continue in conjunction with future retirements, future net salvage is estimated at negative f ifty (50) percent. The resulting recommended annual depreciation rate is for this property group is 3.24 percent.

Account 376 - Mains

The Company's current investment in mains totals $78,334,154 and is being depreciated utilizing an annual depreciation rate of 4.05 percent while the current overall average age is 18.6 years. The investment in gas mains is related to several types of pipe, as well as other appurtenant equipment. Accordingly, the investment in the account has been segmented into five (5) sub-account categories which include Steel Mains, Plastic, Valves, Manholes, and Bridge & River Crossing. The Company's mains investment has continually grown over the history of the account through the present day. The compound growth rate of the account investment over the history has aggregated approximately 6.5

percent. An analysis of the Company's overall retirement data was completed via Simulated Plant Analysis Method, which identified that the property group has generally been experiencing a life of 45 years. Furthermore, the Company's investment was analyzed to identify by property group, by individual material and/or property classes. That is, the property investments were segmented between Steel Mains, Plastic Mains, Valves, Manholes, and Bridge and River Crossings. Based upon the completed analysis as well as analysis of various operating companies data an average service life parameter was estimated for each of the subcategory investments within the property group.

The Company's investment in Steel Mains totals $33,849,069, which has achieved a current average age of 27.3 years. Based upon the applicable analysis and consideration of the property group, an Iowa 45-R3 life and curve is estimated as the applicable life of the property group. Application of the estimated service life parameters to the current investment produces an average remaining life of 21.4 years.

The Company's current investment relative to Plastic - Mains is $44,012,975, while the current average age is 12.0 years. Giving consideration to the analysis on the overall historical data, as well as other industry data, an Iowa 45-R3 life and curve is estimated for this property class. The resulting average remaining life of the property group is 33.7 years.

An analysis was completed relative to the Company's historical salvage experience for the period 1968-2001 which demonstrated that the Company has consistently experienced negative salvage for this class of property. The net negative salvage has ranged from approximately negative five(5) percent to more than negative seventy (70) percent. The resulting overall average negative net salvage for the thirty-four (34) year

period was in excess of negative thirty (30) percent, while the recent salvage trend analysis produced an estimated future net salvage of greater than negative sixty (60) percent. Likewise, is anticipated that the Company will continue to experience significant negative net salvage in conjunction with retirement of its mains and that the level of negative salvage will increase in future years as a percent of the original cost due to increasing local regulations and the resulting manpower requirements being placed upon the Company's operations and continued aging of the current plant in service. That is, as the property continues to age the percent of cost of removal relative to the original cost will continue to increase while the percent of gross salvage will decline. Giving consideration to the Company's overall, as well as recent experience, future net salvage relative to this property group is currently estimated at negative sixty (60) percent.

The Company's vintage investment for each property category was applied to the applicable recommended service life and curves resulting in average remaining lives and recommended depreciation rates as summarized in the table below which aggregates to a total account average remaining life depreciation rate of 3.15 percent:

Account 376 - Distribution Mains

Acct. No.	Description	P-I-S 12-31-01	ASL/ Curve	AV Age	ARL	Net Salv. %	Depr. Rate %
376.10	Steel	$33,849,069	45-R3	27.3	21.4	(60)	2.89
376.20	Plastic	44,012,975	45-R3	12.0	33.7	(60)	3.35
376.30	Valves	391,504	40-R2.5	10.7	30.4	(60)	3.78
376.40	Manholes	69,919	45-R3	16.0	29.9	(60)	3.25
376.50	Bridges & River Crossings	10,686	45-R3	6.0	39.1	(60)	3.47
	Total Distribution Mains	78,334,154			3.15		

Account 378 - Measuring and Regulating Station Equipment - General

The investment in this account totals $1,367,334, has attained a current average age of 27.0 years, and is presently being depreciated based upon an annual depreciation rate of 2.30 percent. The measuring and regulating equipment is utilized to regulate its gas pressure within its various service areas to the appropriate level to meet the customer needs. As the Company continues to upgrade and/or modify its operating pressure within its service territory, ongoing changes will be required to the Company's existing measuring and regulating facilities.

Retirements totaling $484,531, which occurred during the 1920-2001 experience band, were analyzed via the Simulated Plant Record Method. Additional analysis of available actuarial retirement data identifies that the retirements have been occurring at an average age of 22 years over the life of the account. The level of property changes have moderated somewhat during the past several years, nevertheless, as indicated it is anticipated that changes will continue as the Company strives to upgrade its system and provide improved customer service in future years. Based upon the historical analysis, an Iowa 40-R1 life and curve is recommended for this property group and when applied to the current surviving assets produces an average remaining life of 23.3 years.

The Company's historic net salvage was studied for the period 1968-2001 which produced an overall average experience of approximately negative two (2) percent net salvage, however, this overall experience was influenced by positive salvage during earlier periods. More recent years have experienced significantly higher negative salvage levels. As noted salvage factors have varied from year to year, however, various recent years have experienced negative salvage and it is anticipated that similar negative experience will

continue into the future. Based upon the overall experience, together with the Company's net salvage trends future net salvage is currently estimated at negative thirty (30) percent. Utilization of the recommended service life and salvage parameters together with the Company's current investment produces and annual depreciation rate of 3.31 percent.

Account 379 - Measuring & Regulating Station Equipment - City Gate

The Company's investment in this account totals $1,009,137, is currently depreciated utilizing an annual depreciation rate of 2.74 percent, and has achieved a current average age of 20.7 years. Retirements totaling $444,438 which occurred during the years 1951-2001, were analyzed via the Simulated Plant Record Method. Based upon the analysis of the available historical date and general content of the account an Iowa 35-R2.5 life and curve is recommended for this property group. Application of the recommended service life parameters to the current surviving investment produces an average remaining life of 18.9 years.

Net salvage relative to the retirements which have occurred throughout the history of this account has averaged approximately twenty-two (22) percent, however, similar to Account 378 - Measuring & Regulatory Station Equipment - General, the net salvage has been declining and turning negative in recent years. Based upon the trends and expected future net salvage for this property class is estimated at negative fifteen (15) percent. Utilization of the recommended service life parameters and the negative fifteen (15) percent net salvage produces an average remaining life depreciation rate of 4.33 percent.

Account 380 - Services

The Company's current investment in Services totals $32,476,717 has achieved a current average age of 15.2 years, and is presently being depreciated utilizing an annual

depreciation rate of 7.60 percent. The investment in this account has grown significantly in recent years having approximately doubled over the past fifteen (15) plus years.

The Company's investment in services is comprised of two categories of material types, namely, Steel, Plastic as well as Farm & Fuel Lines Plastic. An analysis was performed using various reports, as well as other internal data sources, to identify the investment levels for each material type.

As indicated, the current investment in services has been identified by the three (3) material property categories. Similar to the Company's mains investment, it is anticipated that the Company will experience greater levels of property retirements relative to Services than experienced in earlier years due to increased age, as well as the Company's continuing facilities upgrades.

Of the Company's customer services in place approximately forty-nine (49) percent are steel and fifty-one (51) percent are plastic pipe material. Various of the facilities placed during the past thirty plus years are typically coated and wrapped services, while earlier years were bare steel services. However, a large majority of the services placed in more recent years are plastic services. The services range in size from smaller residential to larger industrial Service, however, the overwhelming majority of the facilities are smaller.

Overall retirements totaling $4,079,040, which occurred during the period 1920-2001 experience band, were analyzed via the Simulated Plant Analysis Method. This analysis identifies that recent retirements have generally been increasing over time. Additional analysis of available actuarial retirement data indicates that the recent retirements have been occurring at an average age of 23 years. Given that the trend has continued over a period of time and that the Company's plans are to continue upgrading its service as

required, a general average service life of forty (40) years is estimated based upon the overall experience of the account. A somewhat short life of thirty-five (35) years is estimated relative to the Farm & Fuel Lines sub-category. Application of the estimated average service life parameters (40-R2.5) to the Company's current Steel Services investment produces an average remaining life 18.8 years and the application of the Iowa 40-R3 to the Plastic Services investment produces an average remaining life of 29.0 years.

The Company's historical retirement and salvage data was analyzed for the period 1968-2001 to identify the estimated future net salvage. The Company has experienced average net salvage of approximately negative one hundred thirty-four (134) percent over the thirty-four (34) year period. Net negative salvage had declined modestly during the early 1990's but has generally escalated in more recent years. The net salvage trend analysis ranged between negative thirty-seven (37) percent to more than negative two hundred (200) percent with the overall trend being negative two hundred thirty-one (231) percent. Based upon the Company's experience and negative trends, plus giving consideration to increased labor costs in future years, future net salvage is estimated at negative one hundred seventy-five (175) percent. The resulting composite recommended annual depreciation rate for Account 380 - Services is 7.03 percent.

Account 380 - Services

Acct. No.	Description	P-I-S 12-31-98	ASL/ Curve	AV Age	ARL	Net Salv. %	Depr. Rate %
380.10	Steel	7,683,870	40-R2.5	26.2	18.8	(175)	7.14
380.20	Plastic	24,580,507	40-R3	11.8	29.0	(175)	6.97
380.30	Farm & Fuel Lines	212,340	30-R1.5	12.3	20.6	(175)	9.33
	Total Services	32,476,717					7.03

Account 381 - Meters

The investment in this account totaling $30,462,008 is presently depreciated utilizing an annual depreciation rate of 2.58 percent. The current average age of the property group is 19.3 years and has grown at a compound growth rate of approximately seventeen (17) percent over the life of the account.

Retirements totaling $5,633,345, which occurred over the 1933-2001 experience band, were analyzed via the Simulated Plant Record Method. Additional analysis of available actuarial retirements data identified that recent retirements have been occurring at an average age of 27 years. Due to the continuing increases in regulation and concern of proper metering, continued emphasis will be placed on the proper testing and/or replacement of metering facilities. The life analysis produced a life indication in the range of thirty-five (35) years, accordingly based upon the available experience an Iowa 35-R2.5 life and curve is estimated for this property class. Application of the recommended service life parameters to the Company's current surviving investment produces an average remaining life of 19.9 years.

The Company's historical salvage experience relative to the retirement of meters was analyzed for the period 1968-2001 which identifies that the amount of net salvage being achieved relative to the retirement of meters has been relatively modest. For example, while during 1968 and 1989, the Company achieved sizable amounts of positive net salvage in conjunction with retirements of its meters, more recent years experience has been approaching zero (0) percent. Based upon the historical experience and the general trend, future net salvage is currently estimated at zero (0) percent and when utilized together with the recommended service life parameters produces an annual depreciation rate of 3.19

percent.

Account 383 - Service Regulators

The Company's investment in this account totals $4,296,862, has achieved a current average age of 20.7 years, and is presently being depreciated based upon an annual depreciation rate of 2.37 percent. Additions have been placed into service for this property class continuously over the life of the account with many of the property additions being related to additions of plant in conjunction with medium pressure rebuilds and new customers. Various retirements have also occurred in conjunction with the upgrading of distribution systems to higher pressures, as well as normal ongoing retirements.

Retirements totaling $995,550, which occurred during the 1946-2001 experience band, were analyzed via the Simulated Plant Record Method. The analysis identifies that the retirements have fluctuated from year to year, but have generally been increasing over time in conjunction with the larger investment levels in this account. The overall historic life analysis indicated a life in the range of thirty (30) to thirty-five (35) years. Giving consideration to ongoing life characteristics and management's expectations, an Iowa 35-R3 life and curve is currently estimated for this property class. Application of the proposed service life parameters to the Company's current surviving investment produces an average remaining life of 18.0 years.

The Company's salvage analysis was analyzed for the period 1968-2001 and identified that the Company has experienced levels of positive net salvage, however, much of that salvage experience is attributable to various regulators being sold to plumbing contractors for installation in private company locations. This activity is applicable to the resale of limited asset items and not the net salvage which is anticipated to occur relative

to the Company's overall plant in service. Accordingly, future net salvage is estimated at ten (10) percent. The application of the proposed life and net salvage service life parameters, produces a recommended annual depreciation rate of 2.87 percent.

Account 385 - Industrial Meas. & Reg. Station Equipment

The investment in this account totaling $578,200 is presently depreciated utilizing an annual depreciation rate of 1.91 percent. The current average age of the property group is 18.7 years. The level of retirements relative to the current property in service has generally increased over time. This property within this account is typically driven by the requirements of a limited quantity of larger customers. Accordingly, the Company will continue to monitor its customer requirements, as well as regulatory requirements. These items along with technology changes may drive additional property changes.

Retirements totaling 110,892 which occurred during the 1978-2001 experience band, were analyzed via the Simulated Plant Record Method. Due to the continuing increases in regulation and concern of providing proper service to its larger customers continued emphasis will be placed on assuring that these facilities meet the requirements of its larger customers. Based upon the content of the account analysis results and general industry experience, an Iowa 35-R2 life and curve is recommended for this property group. Application of the recommended service life parameters to the Company's current surviving investment produces an average remaining life of 20.6 years.

In the past, the Company has experienced net salvage relative to the retirements of this asset class, however, most of this salvage actually has been attributable to store returns as apposed to final salvage. In more recent years this experience has turned to negative salvage. Furthermore, the future removal of such plant will require an increasing

level of labor relative to the historical original cost. Accordingly, based upon the available historical trend, as well as experience within the industry, future net salvage is currently estimated at negative fifteen (15) percent and when utilized together with the recommended service life parameters produces an annual depreciation rate of 3.77 percent.

Account 386.2 CNG Refueling Station

The Company's investment in this account totals $432,811, has achieved a current average age of 7.6 years, and is presently being depreciated based upon an annual depreciation rate of 9.35 percent. Additions have been placed into service for this property class continuously over the life of the account with many of the property additions being related to additions of plant in conjunction with meter changes.

Given the young age of the property class no retirements have been experienced to date. An average service life of an Iowa 15-R3 life and curve is estimated for this property class. Application of the proposed service life parameters to the Company's current surviving investment produces an average remaining life of 8.1 years.

Future net salvage is estimated at zero (0) percent and when utilized together with the service life parameters, produces a recommended annual depreciation rate of 3.70 percent.

Account 387.10 - Cathodic Protection Equipment

The Company's investment in this account totals $1,450,657, has achieved a current average age of 16.6 years, and is presently being depreciated based upon an annual depreciation rate of 5.21 percent. Additions have been placed into service for this property class continuously over the life of the account.

Retirements totaling $653,395 which occurred during the 1968-2001 experience

band, were analyzed via the Simulated Plant Record Method. The analysis identifies that while the retirements have varied from year to year, they have generally been increasing in more recent periods in conjunction with the larger investment levels in this account. Based upon the historical analysis results and the expectation that such activity will continue, an Iowa 20-R1.5 life and curve is currently estimated for this property class. Application of the proposed service life parameters to the Company's current surviving investment produces an average remaining life of 10.1 years.

The Company's salvage analysis was analyzed for the period 1967-2001 and the Company's net salvage experience routinely was zero approximately (0) percent. Based upon the historical data, future net salvage is estimated at zero (0) percent and when utilized together with the service life parameters, produces a recommended annual depreciation rate of 5.75 percent.

Account 387.20 - Other Equipment - Other Distribution Equipment

The Company's investment in this account total $557,184, and is being depreciated using an annual depreciation rate of 5.21 percent. Based upon this historical analysis an Iowa 25-R3 life and curve is estimated as the applicable service life parameters for this property group investment. Future net salvage relative to this investment is estimated at zero (0) percent. Application of the recommended service life parameters to the Company's investment produces an average remaining life of 17.8 years and an annual depreciation rate of 1.42 percent.

Account 390.00 - General Structures

The Company's investment in this account totals $1,922,983 which is related to the Company's several structures within its operating system. The surviving investment has

achieved a current average age of 32.9 years and is presently being depreciated based upon an annual depreciation rate of 2.34 percent.

An analysis of retirements totaling $1,655,403, which occurred during the period 1928-2001 were analyzed via the Simulated Plant Record Method, which produced an average service life in the range of 30-35 years. Accordingly, an Iowa 35-R3 life and curve was applied to the Company's surviving investment, which produced an average remaining life of 11.3 years.

While past retirements have generated positive salvage for two (2) recent years, most years within the analysis band produced varying levels of negative salvage. Future net salvage relative to the property contained in this account is estimated at negative ten (10) percent. The resulting annual depreciation rate is 4.61 percent.

Account 391.1 - Office Furniture and Equipment

The Company's investment in office furniture and fixtures totals $544,275, which has achieved a current average age of 26.7 years and is presently being depreciated utilizing an annual depreciation rate of 4.05 percent. Retirements totaling $820,808, which occurred during the 1932-2001 band, were analyzed via the Simulated Plant Record Method which produced a life indication in the range of eighteen (18) plus years. However, given the difficulty in tracking the many items with smaller investment amounts it is likely that numerous items fail to be retired when no longer in service. Accordingly, due to this ongoing difficulty in attaining proper retirements a service life of an Iowa 15-R1 life and curve is estimated for this property group plus, it is proposed that the investment within this property group be amortized over a fifteen (15) year period.

Account 391.3 - Computer Equipment - PC

The Company's current investment in this account totals $780,995, has attained a current average age of 4.4 years, and is presently being depreciated based upon an annual depreciation rate of 12.5 percent. Given the young age of the property group along with the likely under-reporting of retirements which have actually occurred to date, the achieved life indication relative to this property class is likely overstated. While an analysis of general data relative to PC computer type equipment, of which this property group is principally comprised, have general experienced an average service life in the range of eight (8) years, there are various underutilized and/or un-retired items on the Company's books. Furthermore, and more importantly, recently the Company has increased it effort to stay more current with the technological advances inherent within this asset category. This effort is being driven by the continual need for increase processing power (due to software requirements, etc) as well as the reduced cost of the newer equipment platforms. In general, it is widely known that this property class, which is significantly impacted by the technological advances, routinely requires a very high frequency of upgrades and/or replacements.

Based upon this experience and future expectation of ongoing rapid changes in future years an Iowa 5-R2 life and curve is estimated for this property. Application of the service life parameters to the Company's investment produces an average remaining life of 2.4 years. Future net salvage is estimated zero (0) percent and the resulting annual depreciation rate is 26.02 percent.

Account 392.10 - Transportation Equipment (Non-Utilized)

The present surviving investment in this account totals $147,187, has attained a

current average age of 2.8 years, and is presently being depreciated utilizing an annual depreciation rate of 5.74 percent. Retirements totaling $14,887, which occurred during the 1992-2001 experience band, were analyzed via the Simulated Plant Record Method and a life indication in the range of eight (8) years. Accordingly, an average service life of an Iowa 8-R3 is estimated, based upon the life estimate for this property group, it is recommended that each vintage investment be amortized upon a eight (8) year average life. Application of the recommended life and curve to the Company's current surviving investment produces an average remaining life of 5.3 years.

Future net salvage is estimated at fifteen (15) percent and the resulting proposed implicit annual depreciation rate is 4.36 percent.

Account 392.20 - Transportation Equipment - Utilized

The investment in this account totaling $6,080,561, which currently is depreciated utilizing an annual depreciation rate of 5.74 percent, has current attained an average age of 4.7 years.

Retirements totaling $2,872,353, which occurred during the period 1995-2001, were analyzed for the overall experience period, as well as the various other interim bands. This analysis shows that historically much of the Company's property in this account is routinely being replaced in the range if five (5) years, resulting in a service life indication of six years or less. Based upon the Company's recent experience, an Iowa 6-R3 life and curve are recommended for this account. Application of the proposed service life parameters to the Company's current surviving investment produces an average remaining life of 2.3 years.

An analysis of the Company's retirements and related salvage during the period 1968-2001 indicates that the Company has received positive salvage relative to disposal

of its automobiles in the past. The analysis identifies that the Company's average net salvage totaling $1,359,083 has averaged in the range of 17-18 percent. Based upon the overall historic experience, future net salvage of fifteen (15) percent was incorporated in developing the resulting depreciation rate for this property. Utilizing the estimated average service life and salvage factors together with the Company's current surviving investment produces an average remaining life depreciation rate of 21.13 percent.

Account 393 - Stores Equipment

The Company's investment in this account totals $186,729, has attained a current average age of 30.8 years, and is presently being depreciated utilizing an annual depreciation rate of .90 percent. The Company's investment in this account is somewhat limited and is related to general storeroom equipment located at the Company's various operations warehouses. Retirements totaling $15,323, which occurred during 1920-2001 years, were analyzed via the Simulated Plant Record Method which produced a service life indication of an Iowa 35-R3 life and curve.

An analysis of the Company's salvage experience was completed for the period 1968-2001 to identify the level of net salvage achieved with past retirements. The result of the analysis indicates that the Company has experienced only minimal net salvage. Based upon the Company's experience in many years, as well as general industry experience, future net salvage is estimated at zero (0) percent and the resulting annual amortization rate is 2.49 percent.

Account 394 - Tools, Shop and Garage Equipment

The investment in this account totaling $3,187,752 is related to tools, garage, and work equipment utilized by the Company's employees in providing service to the Company's

customers. Accordingly, the Company maintains investment in this account within four (4) separate sub-account categories which include Tools, Shop & Garage Equipment - Non Utilized, Tools, Shop and Garage Equipment Utilized, Vehicle Maintenance Equipment and Vehicle Refueling Equipment. Based upon the content of each property group and the completed analysis the average service life parameters were estimated for each of the subcategory investments.

The Company's investment in Tools, Shop & Garage Equipment - Non Utilized, totals $2,495,422. Retirements from the property group have totaled $1,1893,769 over the life of the account which have produced a life indication in the range of twenty-five (25) years. However, given the difficulty in tracking the many items with smaller investment amounts it is likely that numerous items fail to be retired when no longer in service. Accordingly, due to this ongoing difficulty in attaining proper retirements a service life of an Iowa 18-R1.5 life and curve is estimated for this property group. Furthermore, it is proposed that the investment within this property group be amortized over a eighteen (18) year period.

The Company's investment in Tools. Shop & Garage Equipment - Utilized, totals $299,810. An analysis of $1,632,696 retirements form this property category via the Simulated Plant Record Method, produced a life indication of an Iowa 20-R1 life and curve. is estimated as the applicable life of the property group. Similar to Account 394.1, given the difficulty in tracking the many items with smaller investment amounts it is likely that numerous items fail to be retired when no longer in service. Accordingly, due to this ongoing difficulty in attaining proper retirements a service life of an Iowa 18-R1 life and curve is estimated as the applicable life for this property group. Accordingly, the recommended amortization period for the asset investments is eighteen (18) years.

The current investment in Vehicle Maintenance Equipment totals only $31,177. A service life representative of an Iowa 20-R3 life and curve is estimated for this property group. Likewise, it is proposed to amortize the investments within this property groups over twenty (20) years.

The Company's investment relative to Vehicle Refueling Equipment totals only $361,344. Giving recognition to the property groups content and various analysis on Iowa 15-R3 life and curve is estimated for this property class. A fifteen (15) year amortization period is proposed for this asset class.

The Company's vintage investment for each property category was applied to the applicable recommended service life and curve, recommended amortization and resulting implicit depreciation rates as summarized in the table below.

Account 394 - Tools, Shop and Garage Equipment

Acct. No.	Description	P-I-S 12-31-00	ASL/ Curve	Amort. Period (Yrs.)	Net Salv. %	Amort. Rate %
394.10	Tools, Shop & Garage Equip-(Non-Unitized)	$2,495,422	18-R1.5	18	0	6.62
394.20	Tools, Shop & Garage Equip-(Unitized)	299,810	18-R1	18	0	2.40
394.30	Vehicles Maint. Eq.	31,177	20-R3	20	0	5.78
394.40	Vehicles Refueling Equipment	361,344	15-R3	15	0	4.72
	Total Equipment	$3,187,753				

Account 395 - Laboratory Equipment

The present surviving investment in this account totals $271,033, has attained a current average age of 21.3 years, and is presently being depreciated utilizing an annual depreciation rate of 2.32 percent. An insufficient level of historical data is available to

produce any meaningful service life indications. Based upon general industry information and future expectations for the property group, an Iowa 20-R2 life and curve is estimated for this property class. Accordingly, a future amortization period of twenty (20) years is estimated relative to this asset class. Future net salvage is estimated at zero (0) percent resulting in a current implicit annual amortization rate of 7.67 percent.

Account 396.10 - Work Equipment (Trailers)

The Company's investment in this account totals $293,543 and is being depreciated using an annual depreciation rate of 4.83 percent. Based upon this historical analysis, an Iowa 10-R2 life and curve continues to be estimated as the applicable service life parameters for this property group investment. Future net salvage relative to this minor investment is estimated at thirty-five (35) percent. The resulting recommended annual depreciation rate is 5.76 percent.

Account 396.20 - Power Operated Equipment

The Company's current investment in this account totals $4,081,768, which is currently being depreciated utilizing an annual depreciation rate of 4.83 percent. The property investment, which has attained a current average age of 11.3 years. Retirements during the recent history of the account totaling $12,672,235, were analyzed via the Simulated Plant Record Method. The analysis of the data provided a general life indication of seven (7) years. The Company routinely replaces its Power Operated Equipment on a rapid replacement schedule thereby receiving the maximum equipment trade in value and maintaining a modern and efficient work fleet. Accordingly, an average service life of an Iowa 7-R2 is recommended for this property group giving consideration to general industry lives

The Company's available historical salvage data was analyzed during the period 1968 -2001. This analysis indicates that during the period studied the Company has achieved average net salvage of approximately eighty (80) percent. However, the actual level of achieved net salvage is somewhat overstated due to the past accounting treatment of the trade-ins. That is, historically the trade-in amounts have been identified and recorded based upon the value allowed against the full retail price of the newly purchased asset as opposed to the actually lower level trade-in in price against the normal market price for the purchased equipment. While the net purchase price is the same under either scenario, the Company's historical accounting treatment of the trade-ins results in an overstatement of the net salvage being received for the traded equipment. Accordingly, based upon this analysis future net salvage for this asset class is estimated at sixty (60) percent. The Company's current book depreciation reserve relative to this property class aggregates approximately fifty-five (55) percent of original cost. However, given the recent practice of upgrading back hoes and trenchers on a short cycle the Company is currently experiencing high levels of net salvage. Flowing this activity through the normal depreciation rate calculation would presently produce a negative depreciation rate even though the depreciation reserve is significantly less than original cost. Because of this circumstance it is recommended that the depreciation rate be currently set at zero (0) percent and that no future depreciation expense be recorded until a significant change occurs to the depreciation reserve as a percent of original cost declines significant and/or the plant replacement patterns change significantly.

Accordingly the recommended annual depreciation rate for this property group is estimated at zero (0) percent.

Account 397 Communication Equipment

The Company's maintains its investment in this account in six (6) categories of communication equipment, namely Fixed Radio Equipment, Radio Equipment Mobie, Telephone, Supervisory and Telemetering Equipment, SCADA System, and Networking Equipment. An analysis was performed using various reports, as well as other company data sources, to identify the investment levels for each equipment group.

The Company's current investment in Radio Communication Equipment - Fixed totals only $481,655 for which the current depreciation rate is 3.67 percent. Based upon the property group an Iowa 15-R3 life and curve is estimated relative to this investment and is the basis of the recommended amortization period for this property group. Application of the estimated service life parameters to the current surviving investment produces a current implicit amortization rate of 7.37percent.

The Company investment in Radio Communication Equipment Mobile totals only $401,528 and is currently being depreciated at an annual rate of 3.67 percent. While the life analysis produced a general life indication of approximately twenty (20) years, an average service life of fifteen (15) years is estimated for this property group based upon rapid changing technology and operating practices. The applicable amortization period of the estimated 15-R3 life and curve to the current investment produces a current implicit amortization rate of 7.34 percent.

The remaining investment relative to General Telephone Communication Equipment totals only $90,518. An Iowa 10-R1 life and curve is estimated for this property class based upon the Company's historical and general industrial information. The resulting proposed implicit amortization rate is 9.88 percent.

The Company's investment in Supervisory and Telemetering Equipment totals only $124,167. An Iowa 10-L1 life and curve is estimated as the applicable service life characteristics. The resulting implicit amortization rate is 0.25 percent.

The Company's present in SCADA System totals only $30,894. A service life representative of an Iowa 8-R3 life and curve is estimated for this property class. The recommended current implicit amortization rate is 0 percent.

The Company's investment in Networking Equipment totals only $30,338. Giving recognition to the equipment type within the property group (which is similar to computer type equipment), an Iowa 5-R3 life and curve is estimated for this class of property. The resulting implicit annual amortization rate is 26.26 percent.

The Company's vintage investments for each property category, the applicable recommended service life parameters and recommended implicit amortization rates are summarized in the table below.

Account 397 - Communication Equipment

Acct. No.	Description	P-I-S 12-31-01	ASL/ Curve	Amort. Period (Yrs.)	Net Salv. %	Amort. Rate %
397.10	Radio Communication Equipment (fixed)	$481,655	15-R3	15	0	7.37
397.20	Radio Communication Equipment (mobile)	401,528	15-R3	15	0	7.34
397.30	General Telephone Communication Eq.	90,518	10-R1	10	0	9.88
397.50	Supervisory & Telemetering Equipment	124,167	10-L1	10	0	0.25
397.60	SCADA	30,894	8-R3	8	0	0.00
397.80	Networking Equipment	30,338	5-R3	5	0	26.26
	Total Equipment	$1,159,100				

Account 398 - Miscellaneous Equipment

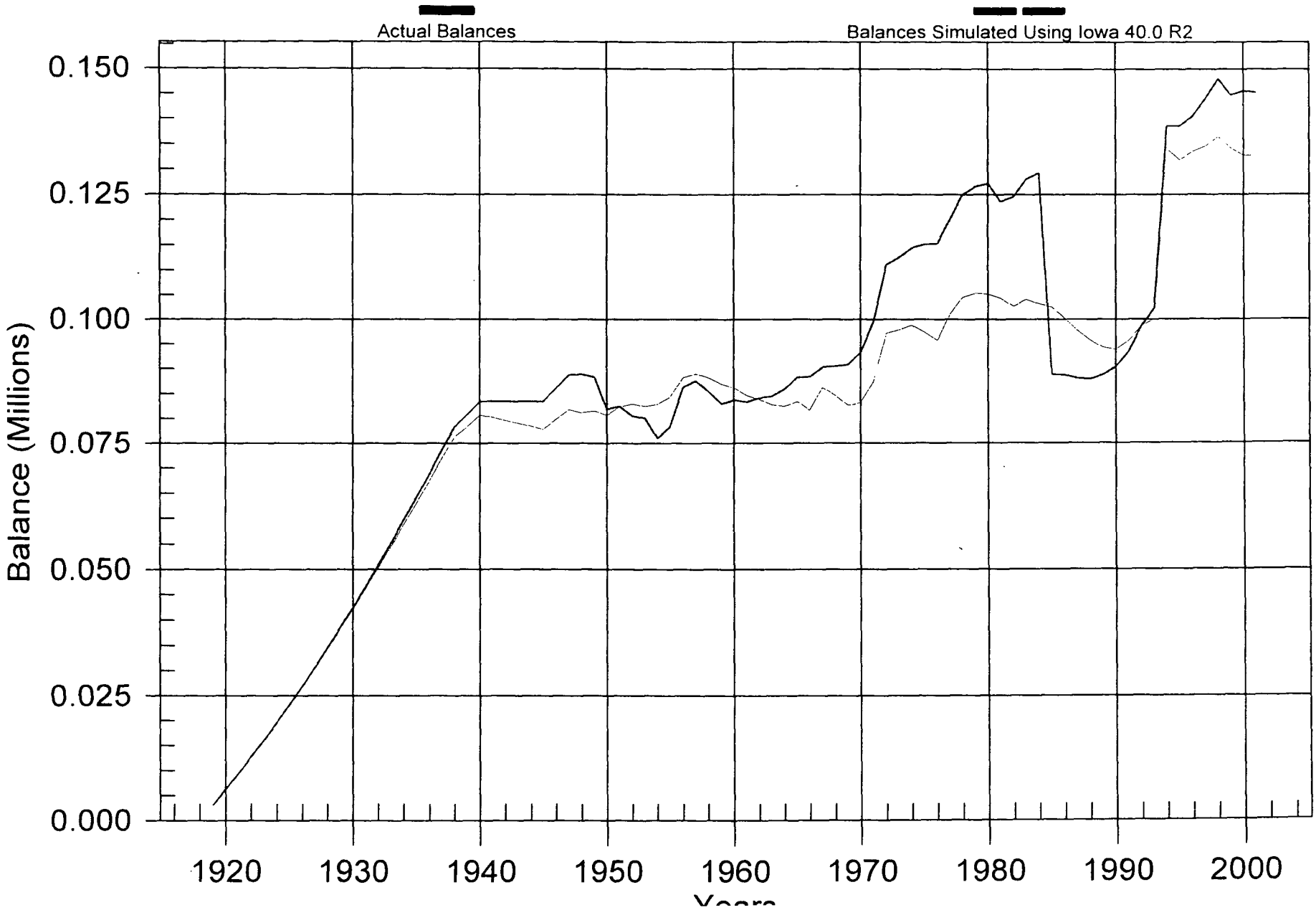
The present surviving investment in this account totals $145,270, has attained a current average age of 39.0 years, and is presently being depreciated utilizing an annual depreciation rate of .59 percent. Retirements totaling $106,249, which occurred during the years 1919-2000, were analyzed via the Simulated Plant Record Method. An analysis of the Company's historical data produced a life of forty (40) plus years. This resulting life is non-typical and is likely the product of significant levels of unreported retirements. Based upon this analysis, consideration of the general account content, related under reporting of plant assets, and general industry data an average service life of twenty (20) years is estimated for the asset group. Based upon an estimated life and curve relative to the Company's current surviving investment of an Iowa 20-R2 the current implicit annual amortization rate for this property group is 1.27 percent.

Montana-Dakota Utilities Company

Gas Division

398.00 MISCELLANEOUS EQUIPMENT

Actual And Simulated Balances

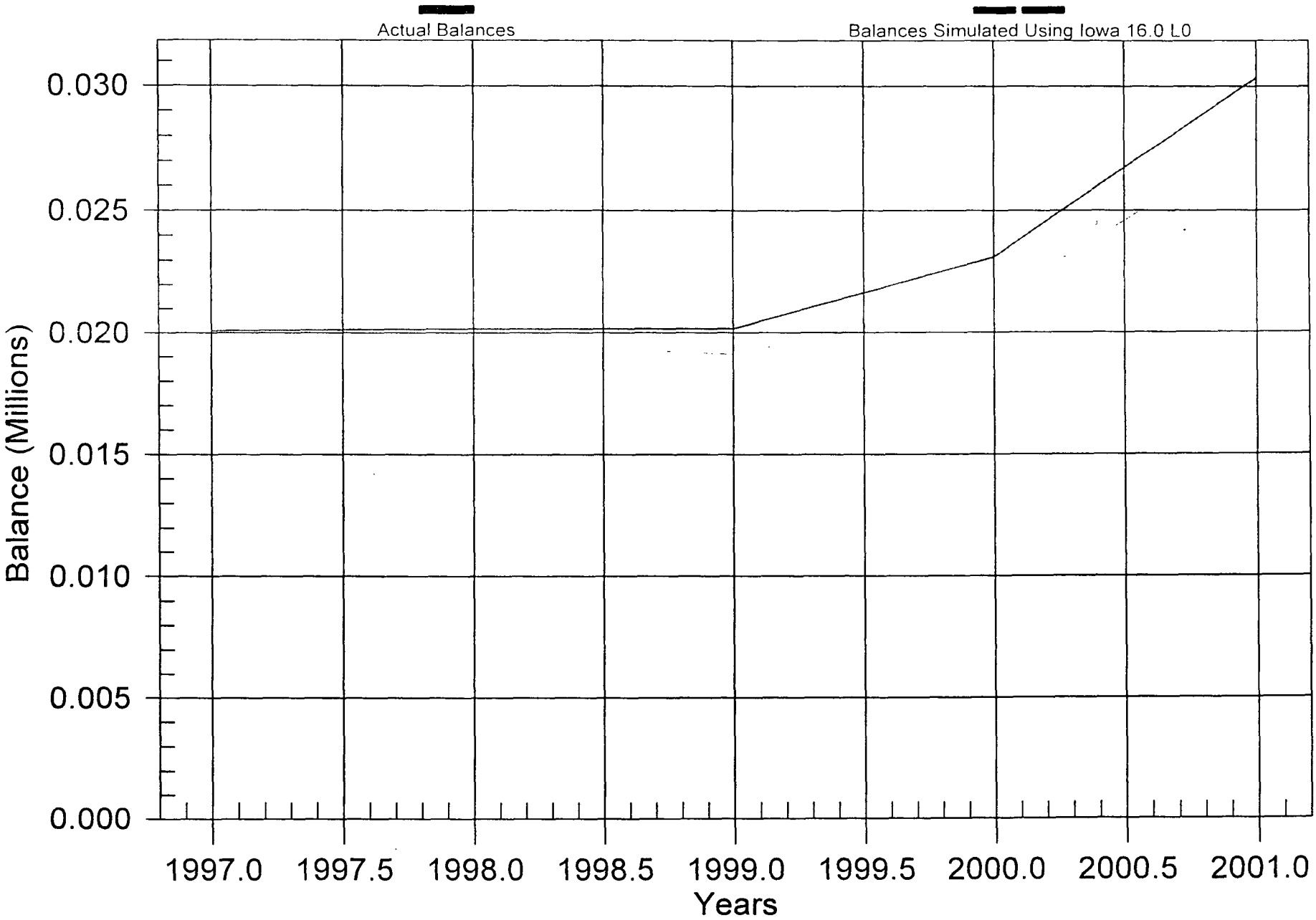


Montana-Dakota Utilities Company

Gas Division

397.80 NETWORK EQUIPMENT

Actual And Simulated Balances

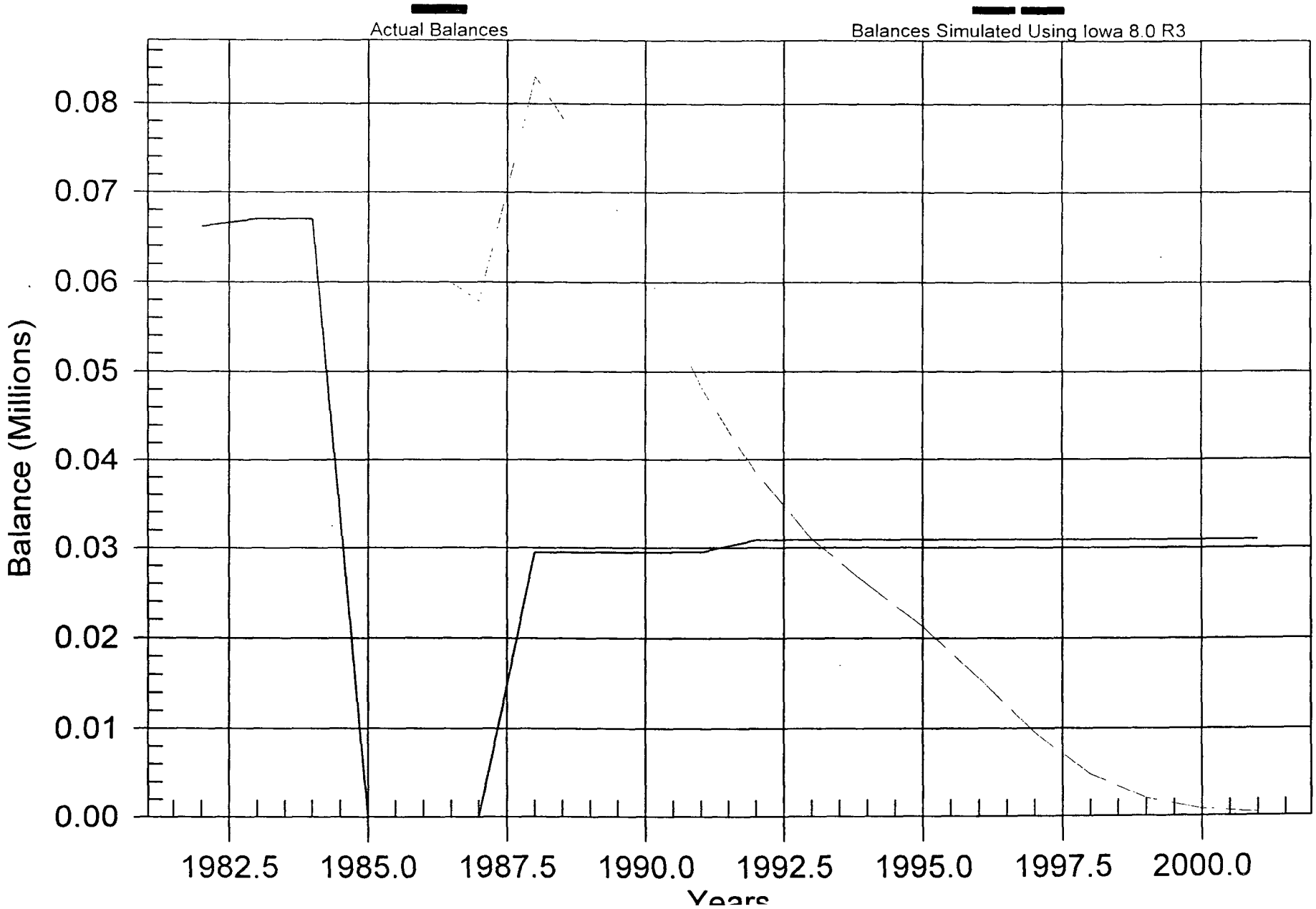


Montana-Dakota Utilities Company

Gas Division

397.60 SCADA SYSTEM

Actual And Simulated Balances

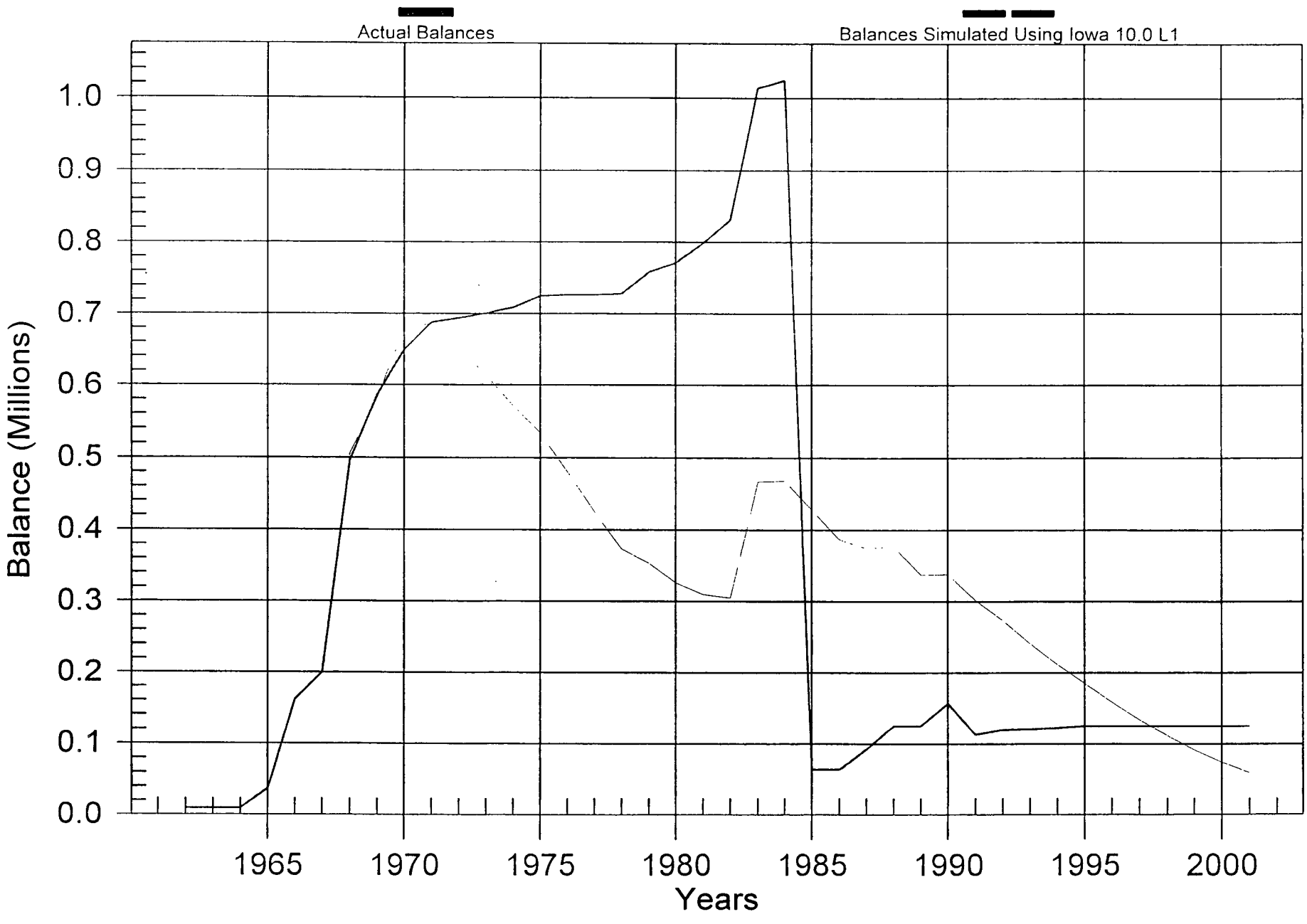


Montana-Dakota Utilities Company

Gas Division

397.50 SUPERVISORY & TELEMETERING EQUIP.

Actual And Simulated Balances

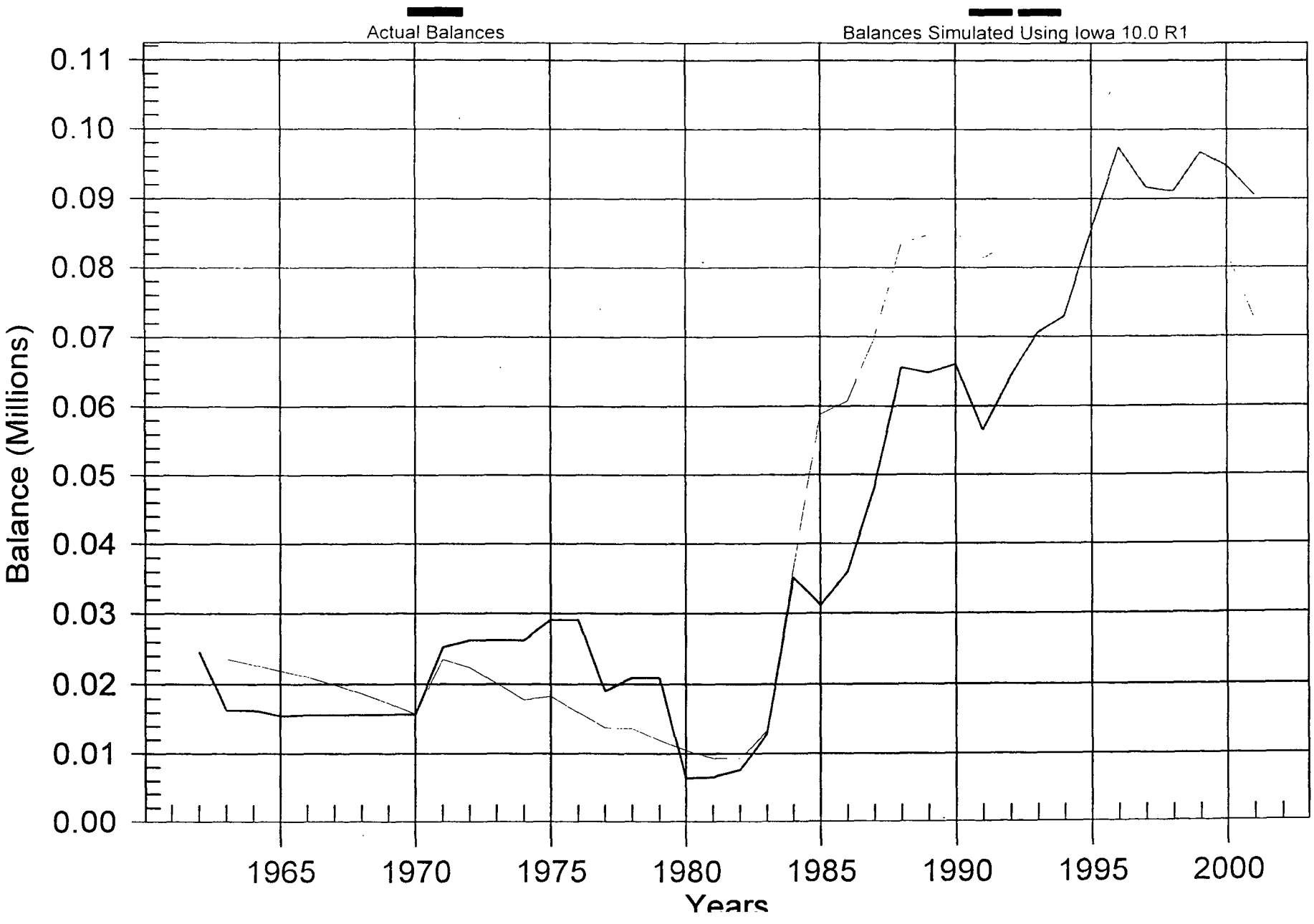


Montana-Dakota Utilities Company

Gas Division

397.30 TELEPHONE COMMUNICATION EQUIP.

Actual And Simulated Balances

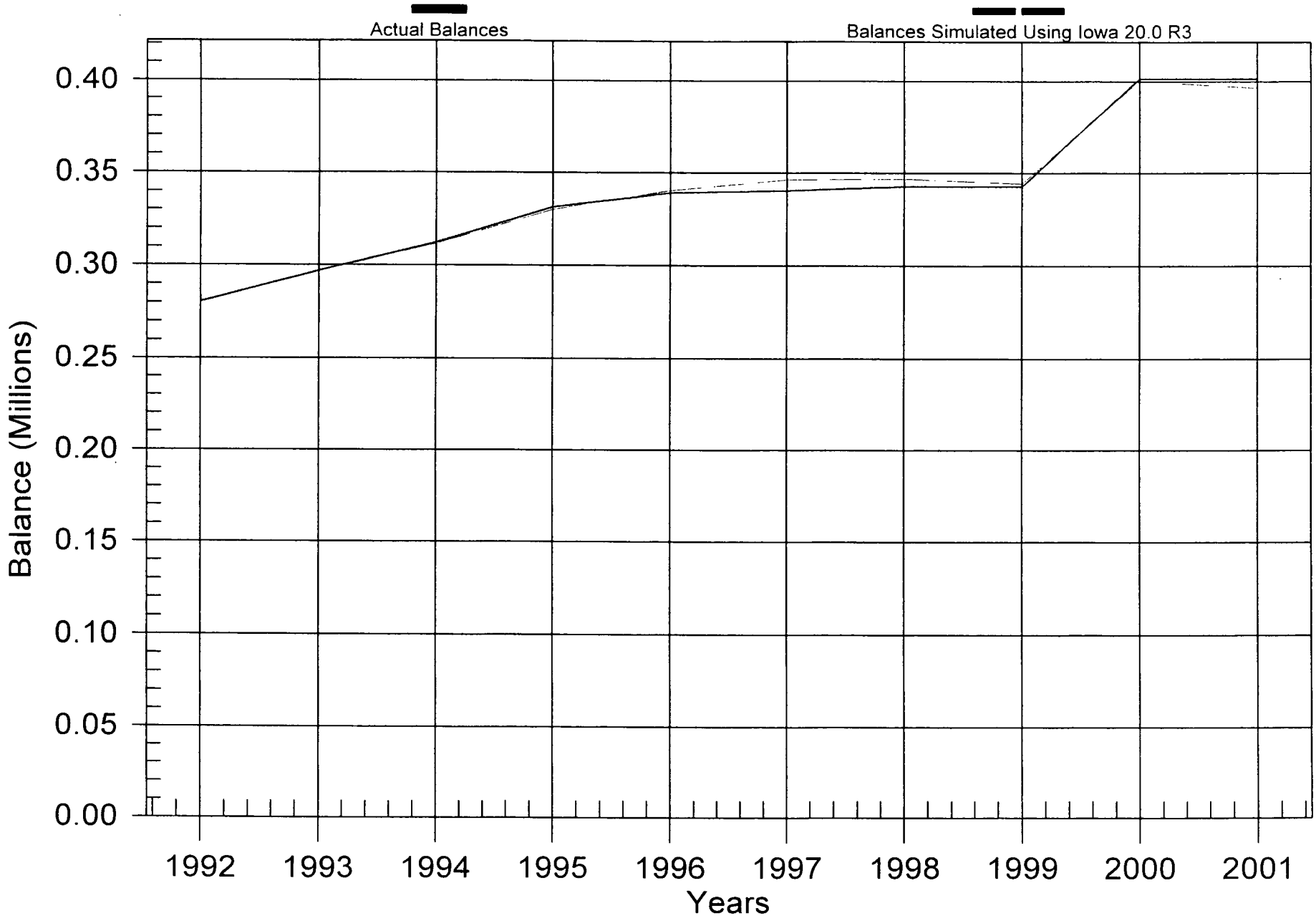


Montana-Dakota Utilities Company

Gas Division

397.20 COMMUNICATION EQUIP. - MOBILE RADIOS

Actual And Simulated Balances

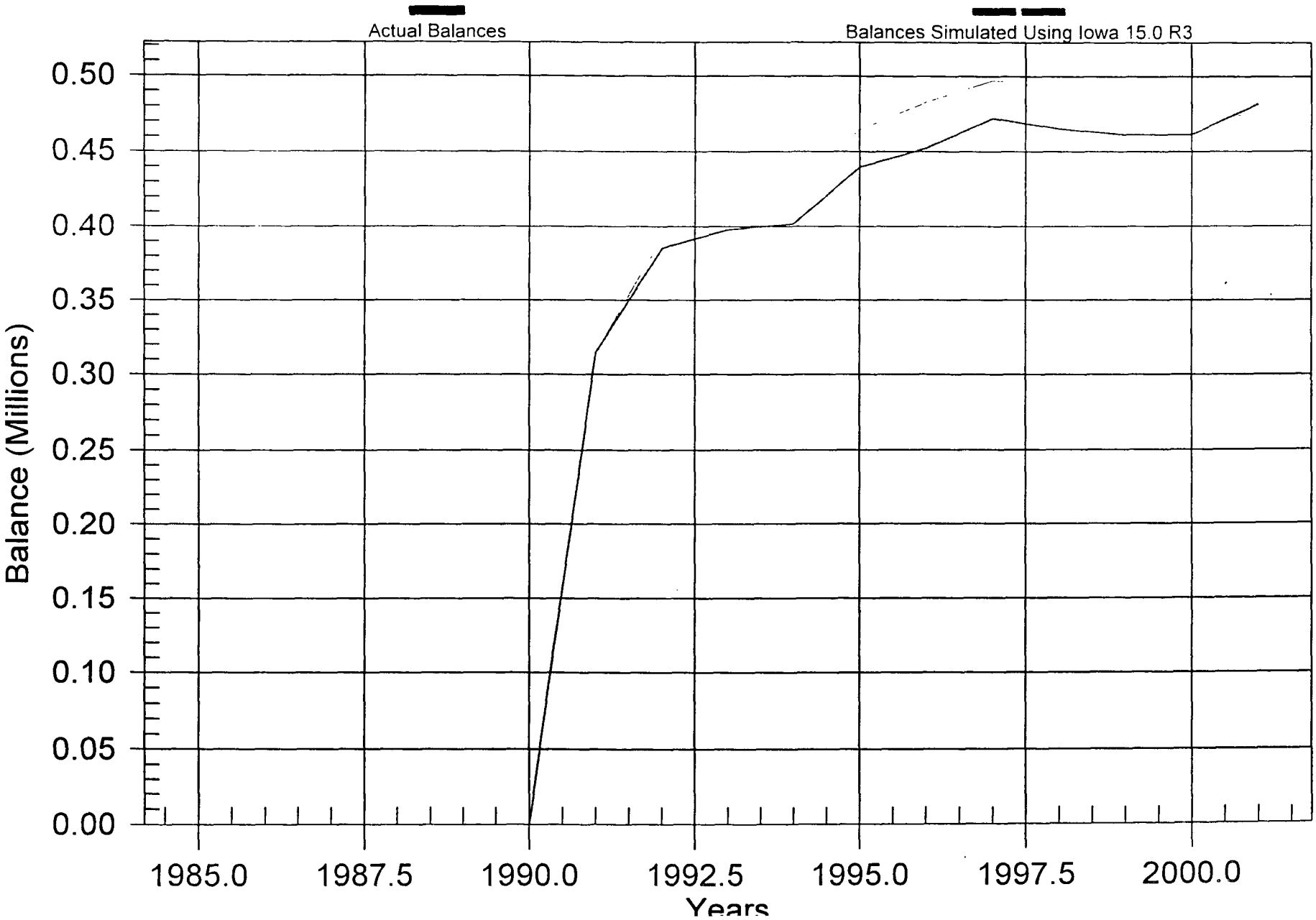


Montana-Dakota Utilities Company

Gas Division

397.10 COMMUNICATION EQUIP. - FIXED RADIOS

Actual And Simulated Balances

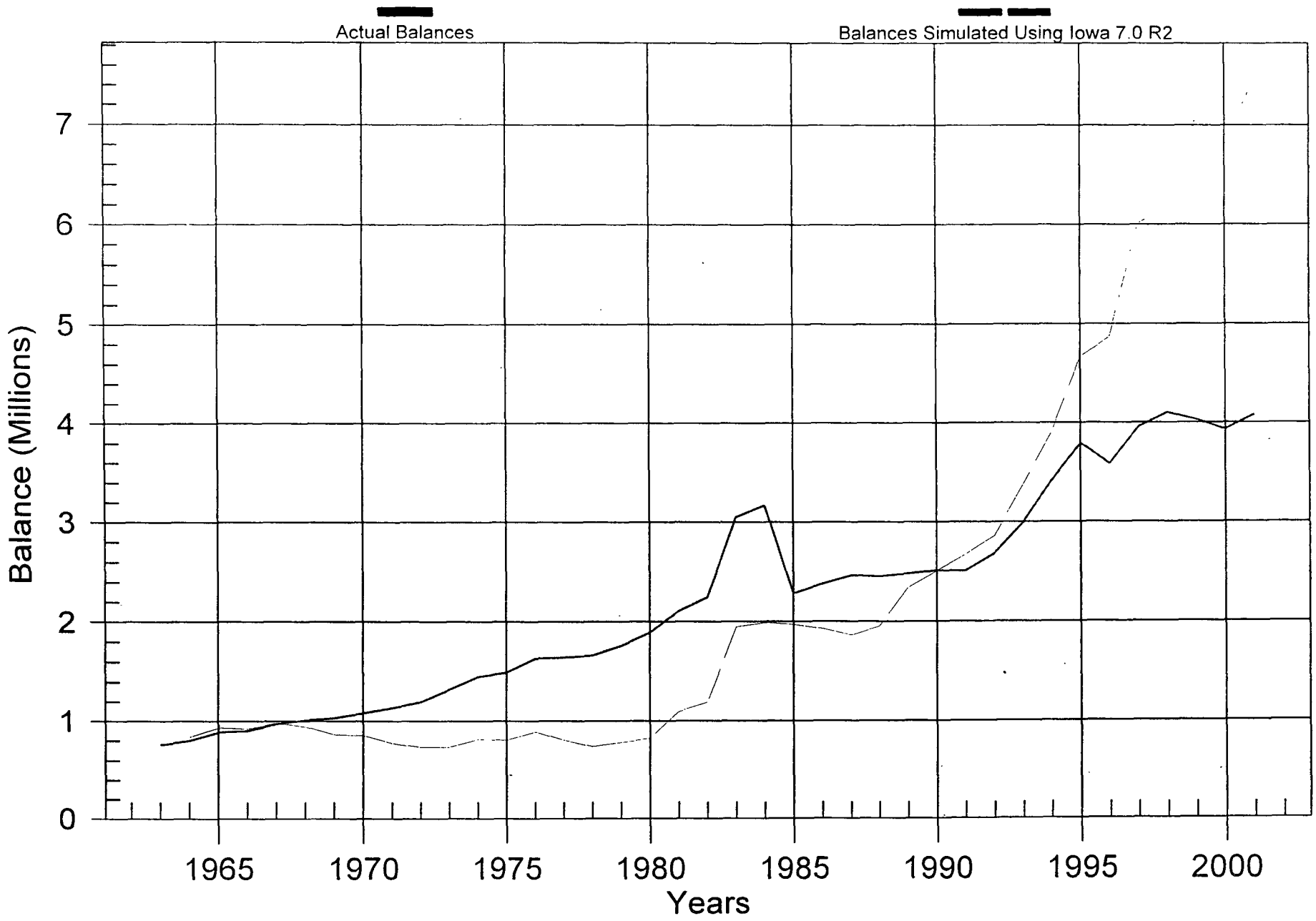


Montana-Dakota Utilities Company

Gas Division

396.20 POWER OPERATED EQUIPMENT

Actual And Simulated Balances

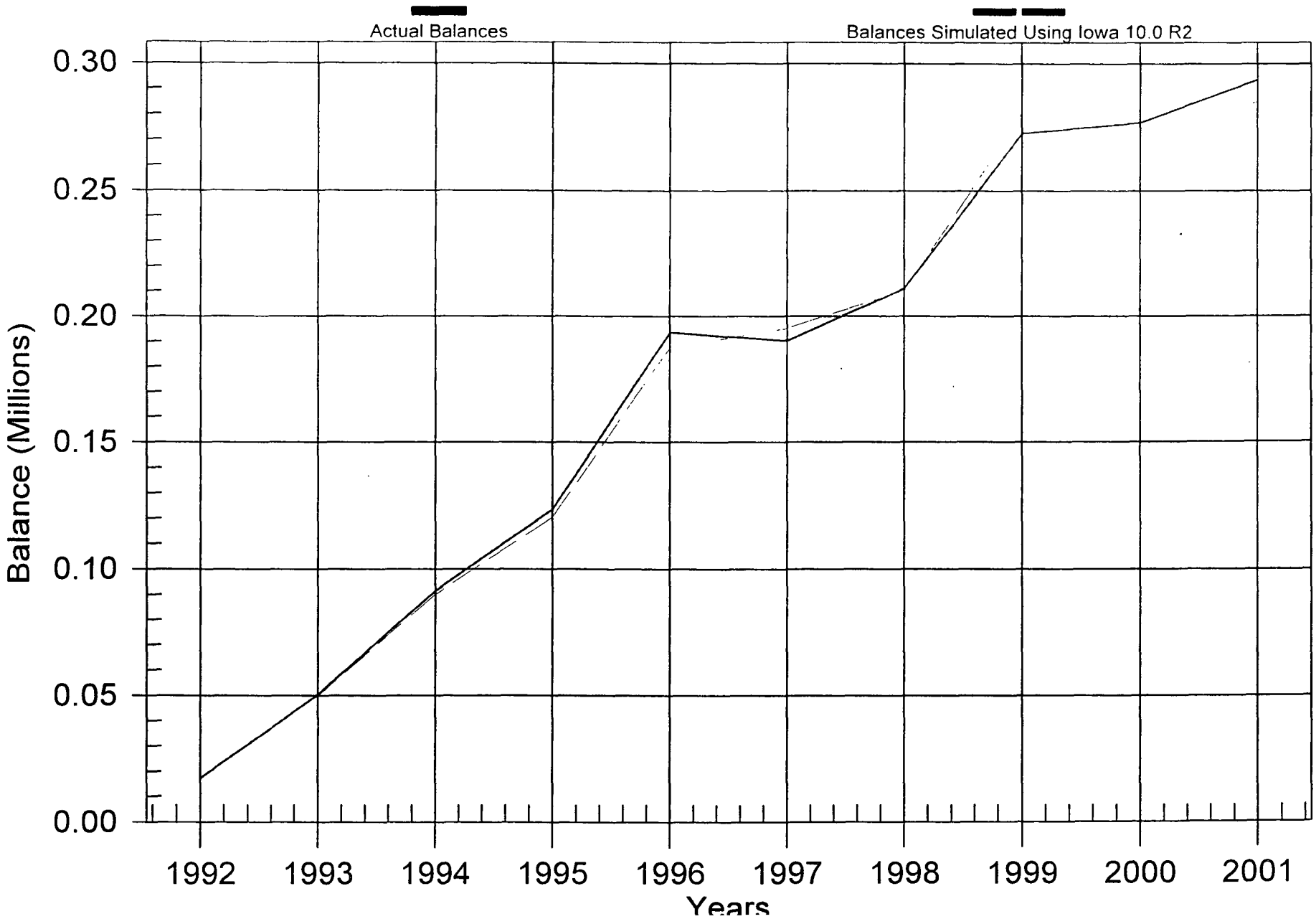


Montana-Dakota Utilities Company

Gas Division

396.10 WORK EQUIPMENT TRAILERS

Actual And Simulated Balances

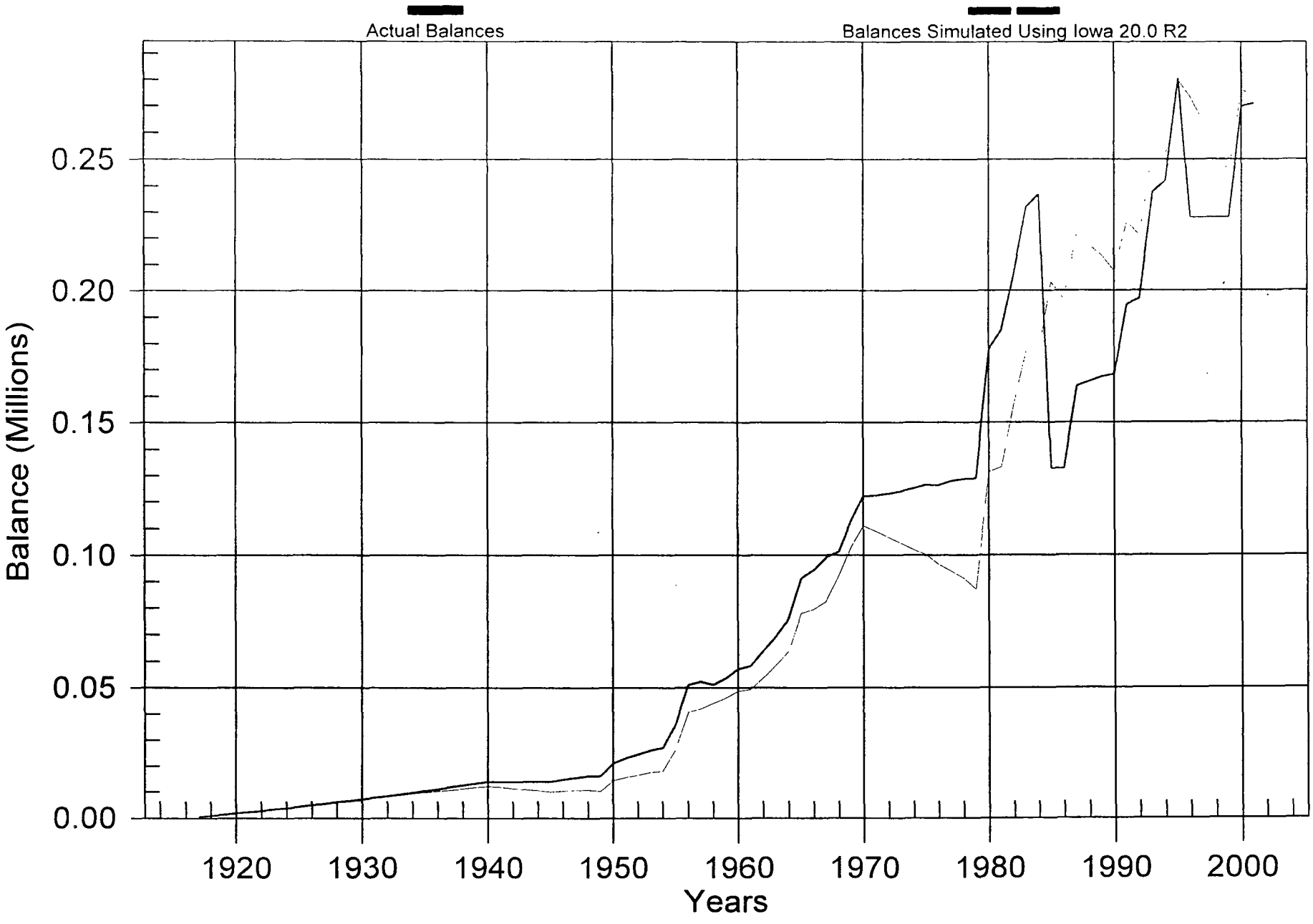


Montana-Dakota Utilities Company

Gas Division

395.00 LABORATORY EQUIPMENT

Actual And Simulated Balances

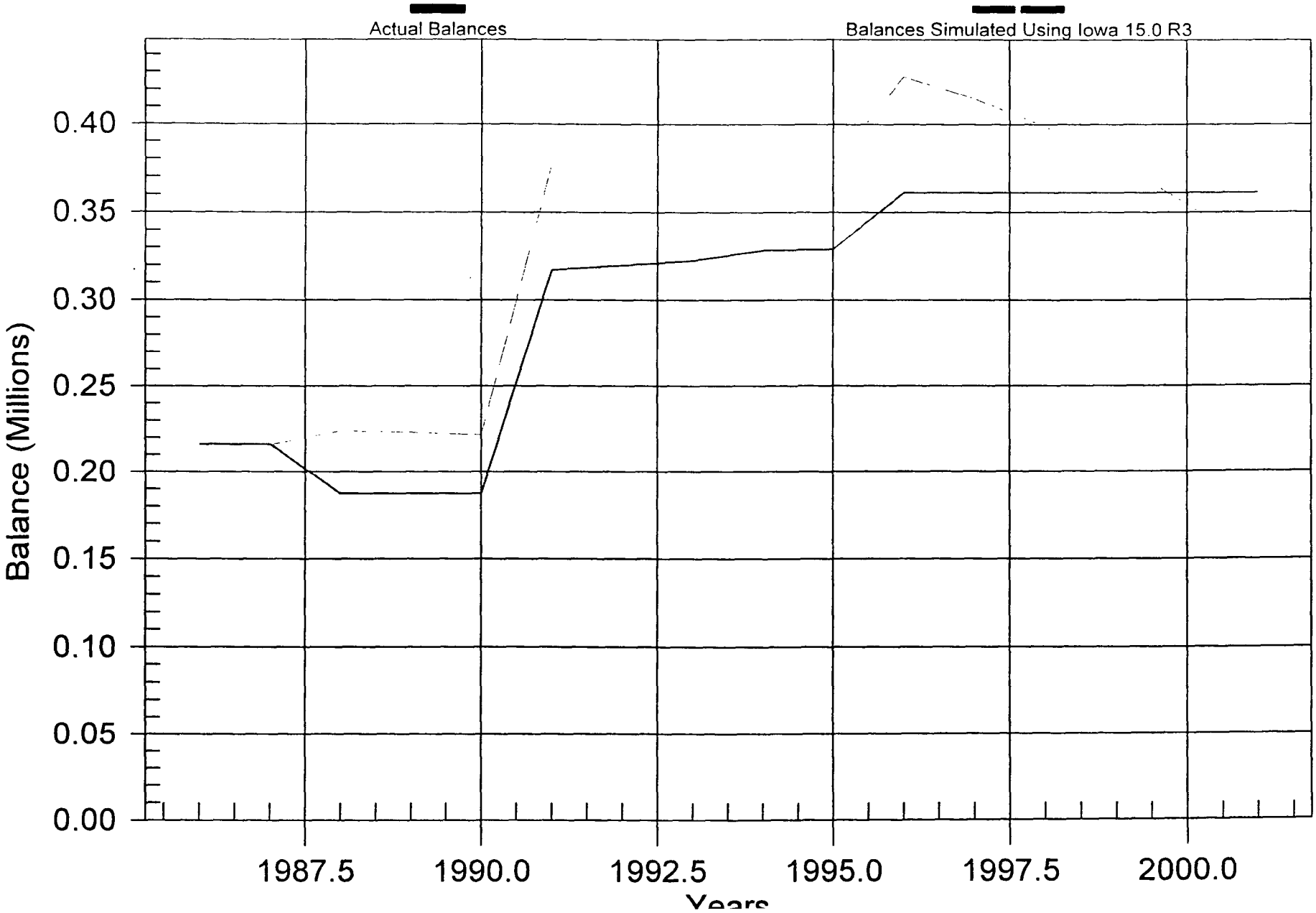


Montana-Dakota Utilities Company

Gas Division

394.40 VEHICLE REFUELING EQUIPMENT

Actual And Simulated Balances

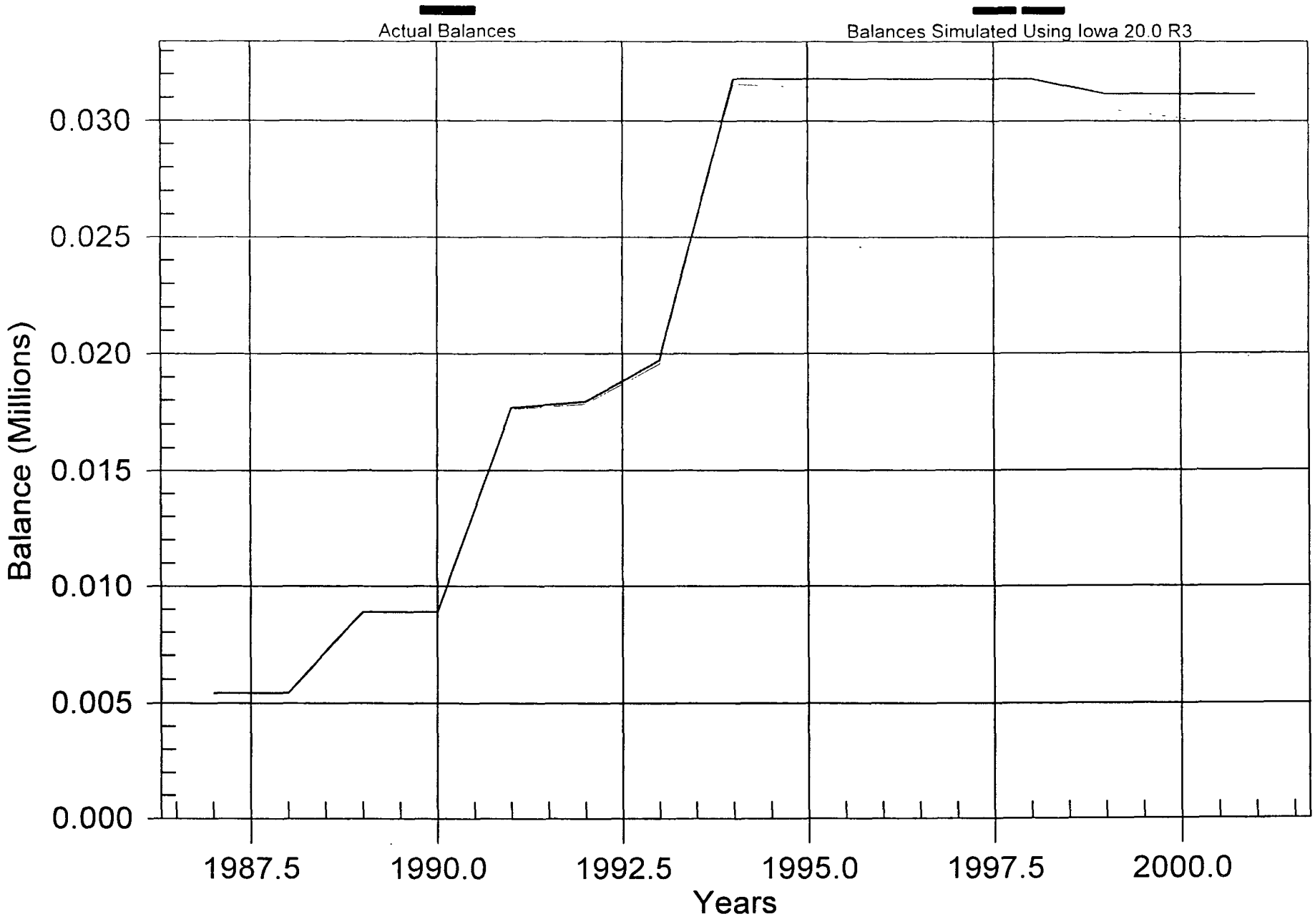


Montana-Dakota Utilities Company

Gas Division

394.30 VEHICLE MAINTENANCE EQUIP.

Actual And Simulated Balances

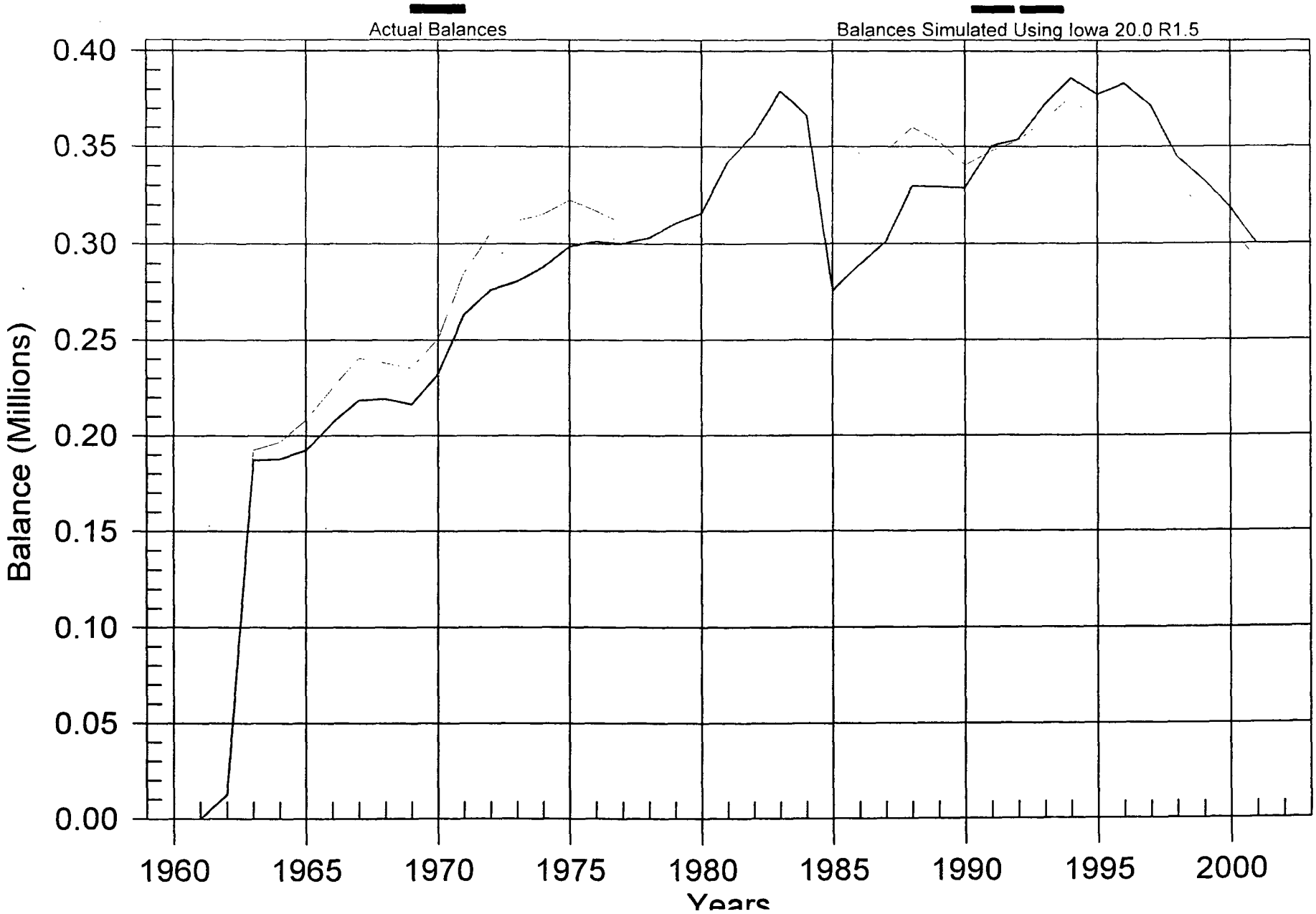


Montana-Dakota Utilities Company

Gas Division

394.20 TOOLS, SHOP & GARAGE EQ. - UNITIZED

Actual And Simulated Balances



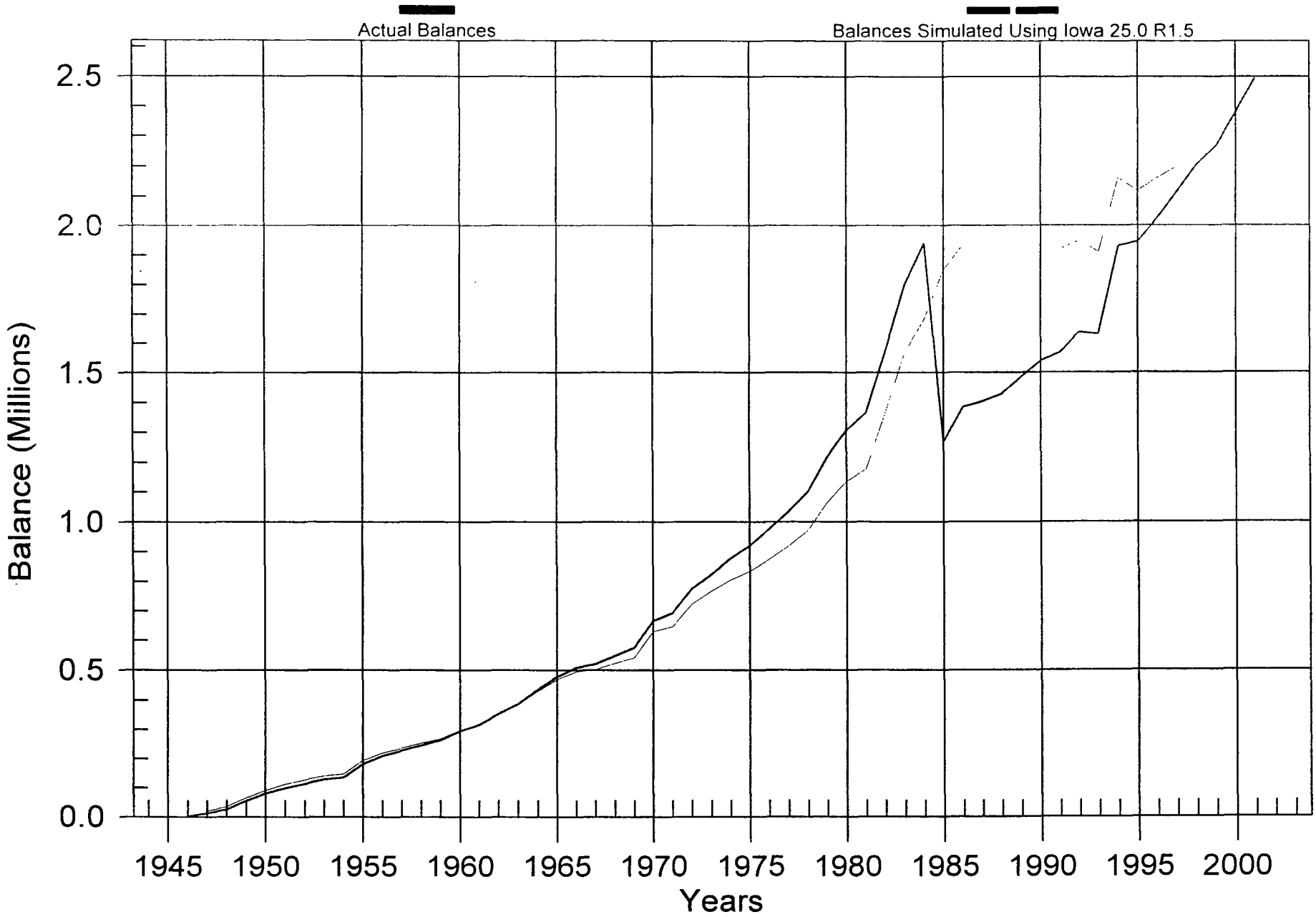
5-20

Montana-Dakota Utilities Company

Gas Division

394.10 TOOLS, SHOP & GARAGE EQ. - NON-UNITIZED

Actual And Simulated Balances

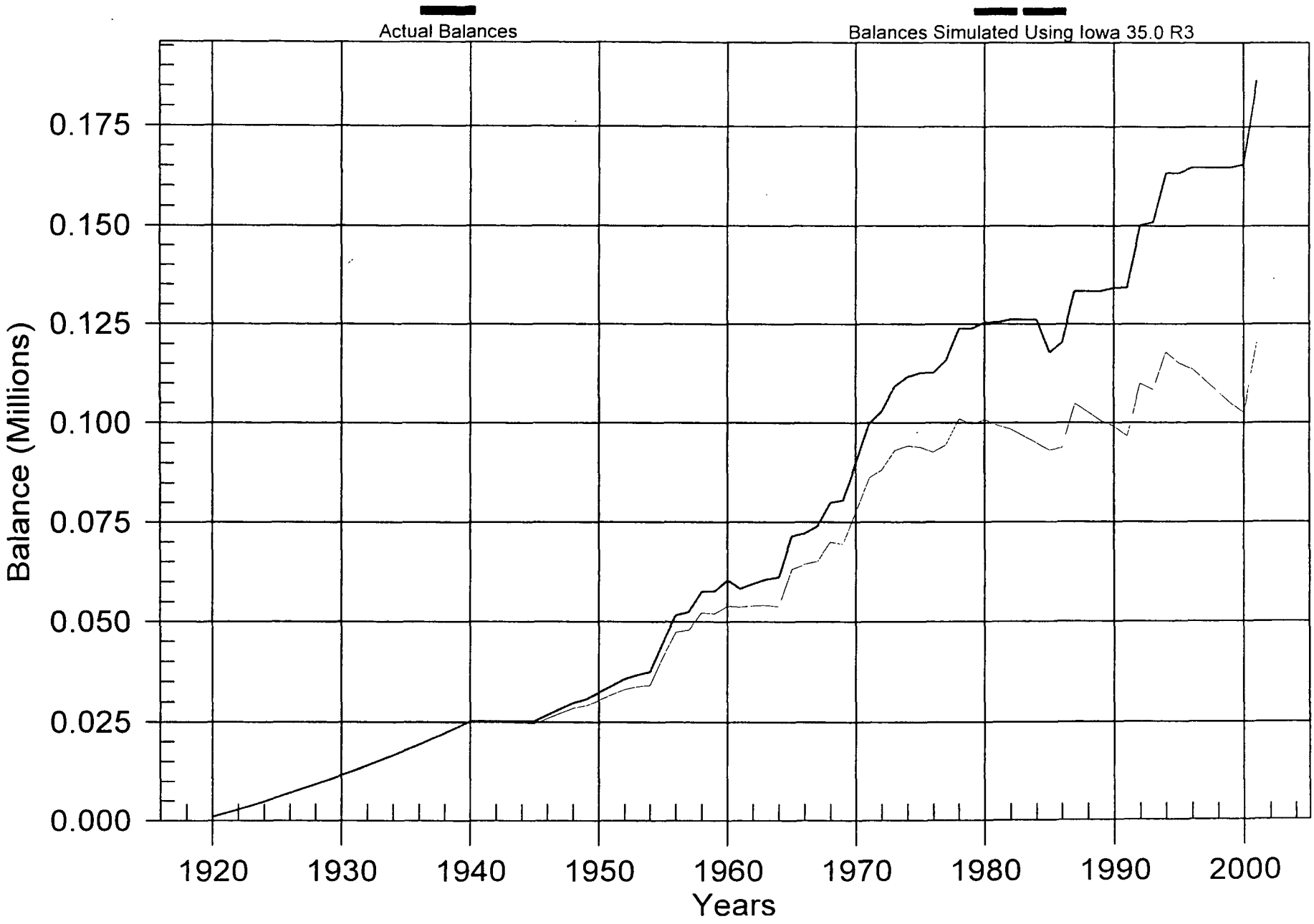


Montana-Dakota Utilities Company

Gas Division

393.00 STORES EQUIPMENT

Actual And Simulated Balances

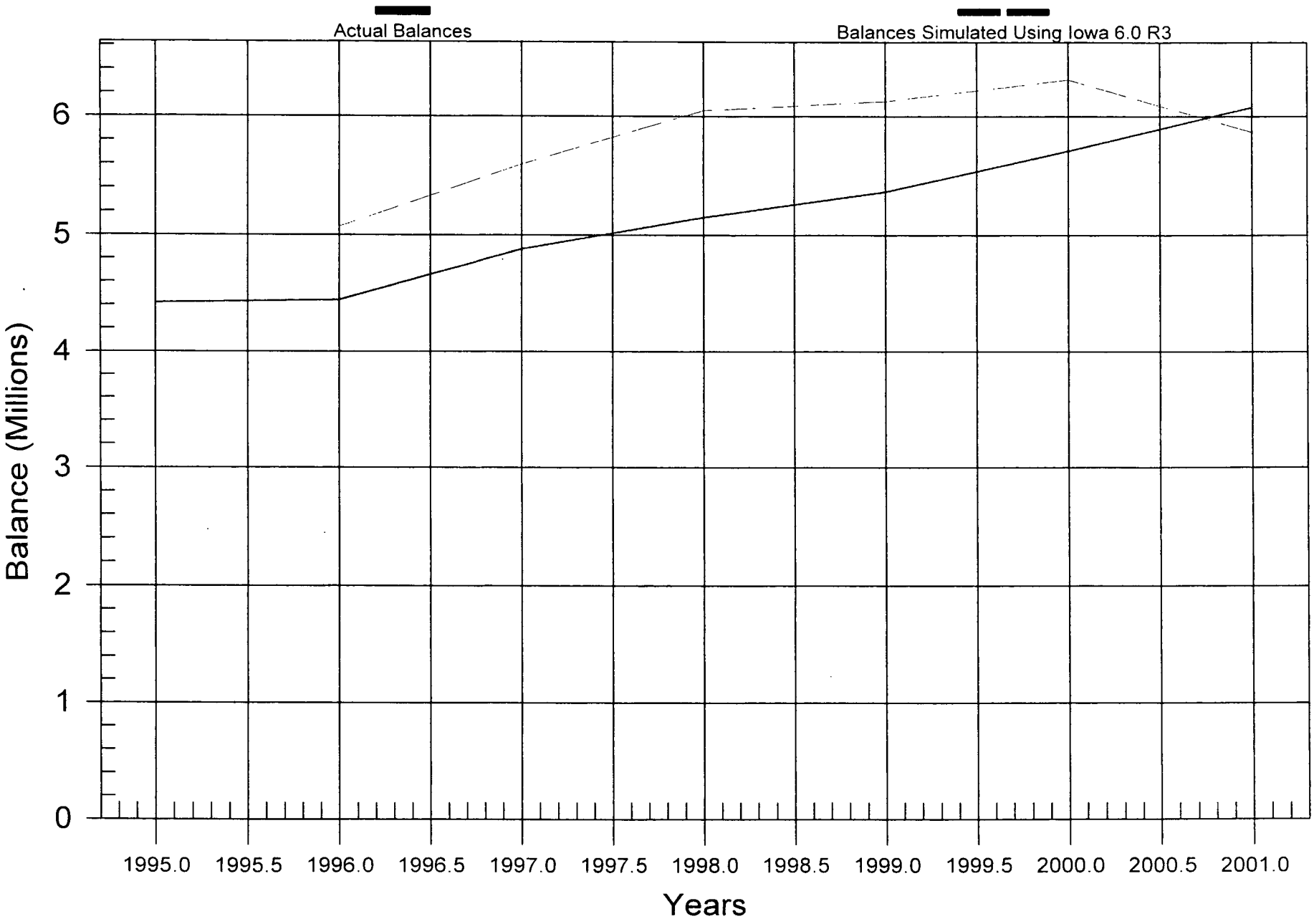


Montana-Dakota Utilities Company

Gas Division

392.20 TRANSPORTATION EQUIPMENT - CARS & TRUCKS

Actual And Simulated Balances

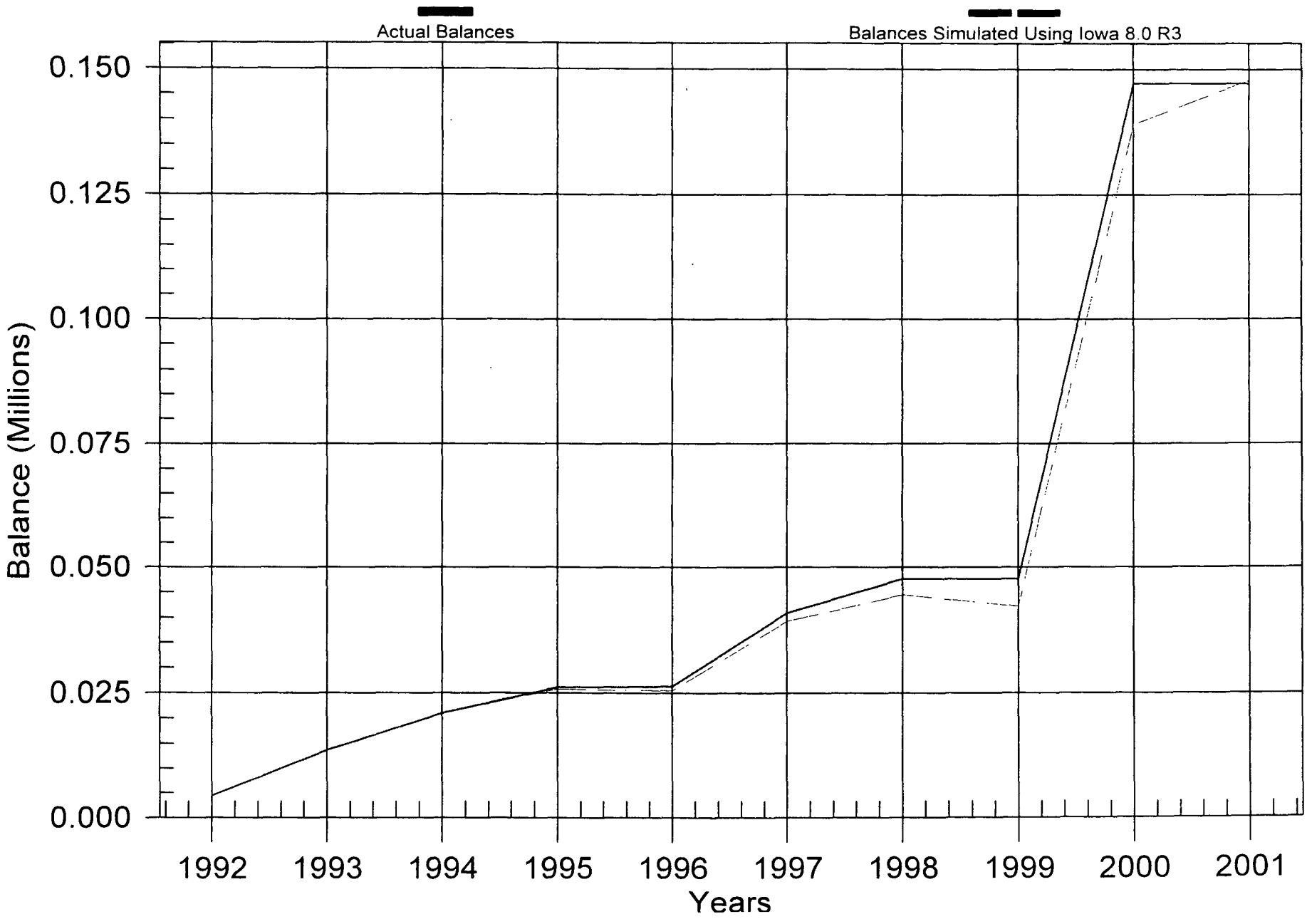


Montana-Dakota Utilities Company

Gas Division

392.10 TRANSPORTATION EQUIPMENT - TRAILERS

Actual And Simulated Balances

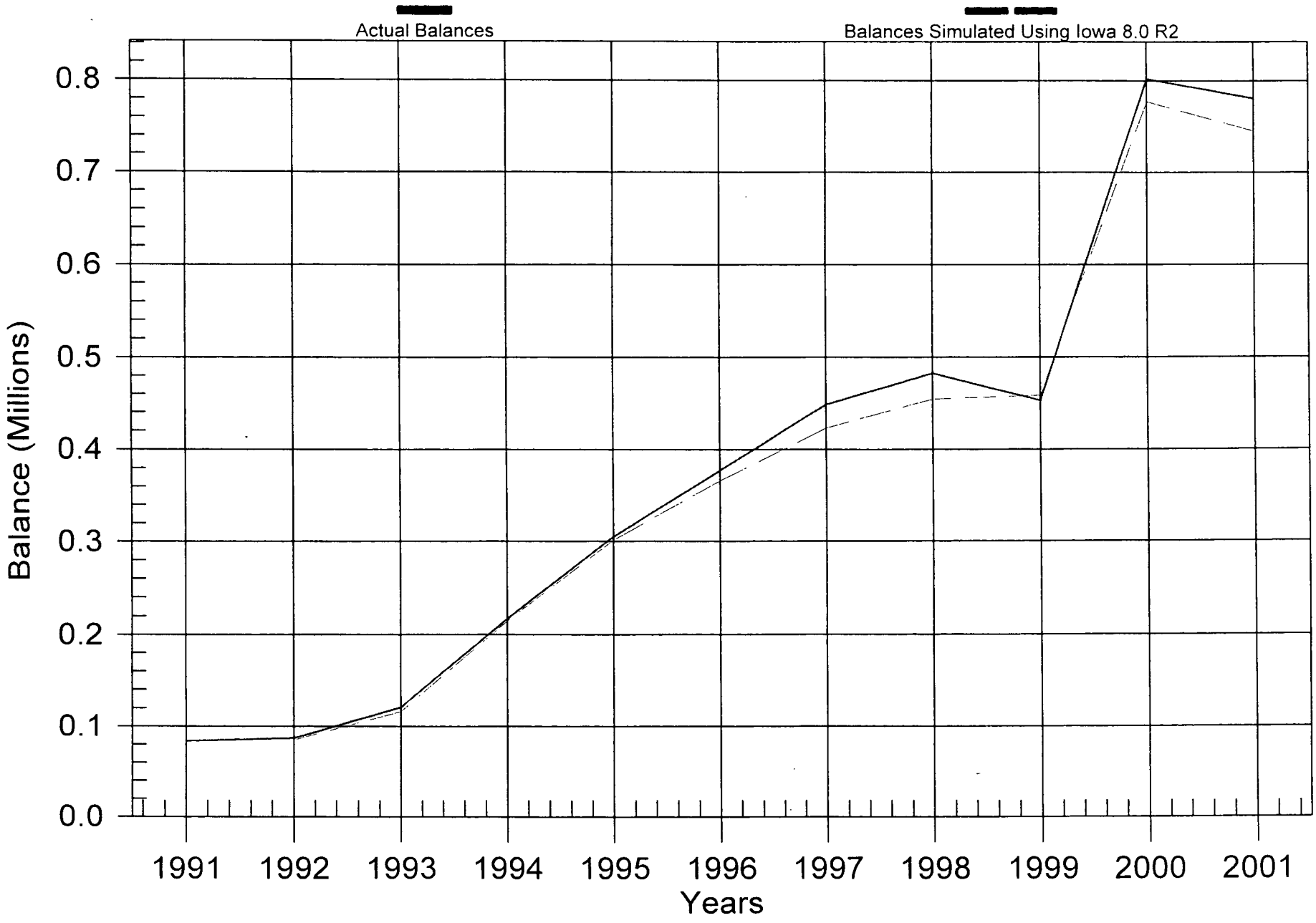


Montana-Dakota Utilities Company

Gas Division

391.30 COMPUTER EQUIPMENT - PC

Actual And Simulated Balances

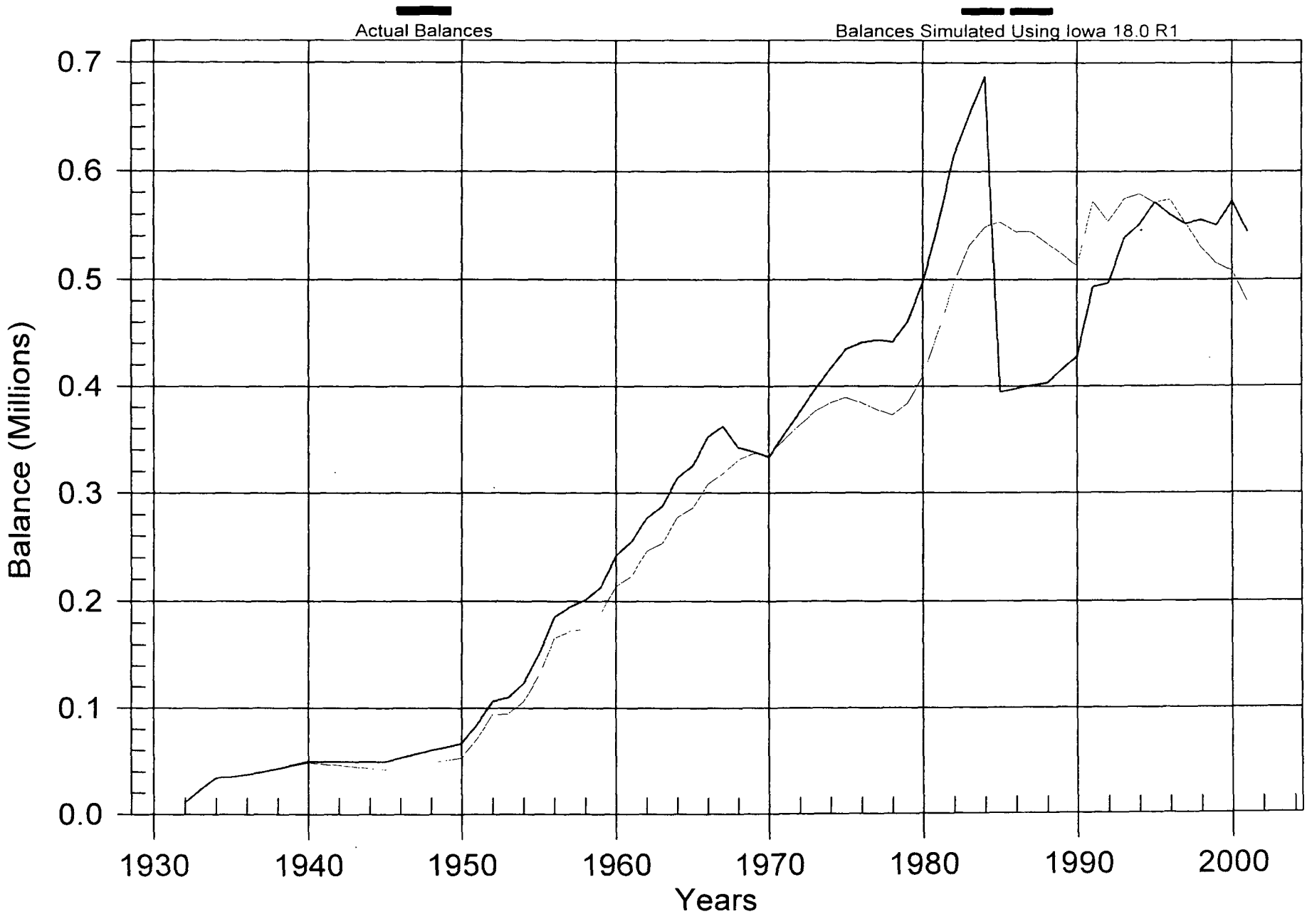


Montana-Dakota Utilities Company

Gas Division

391.10 OFFICE FURNITURE & EQUIPMENT

Actual And Simulated Balances

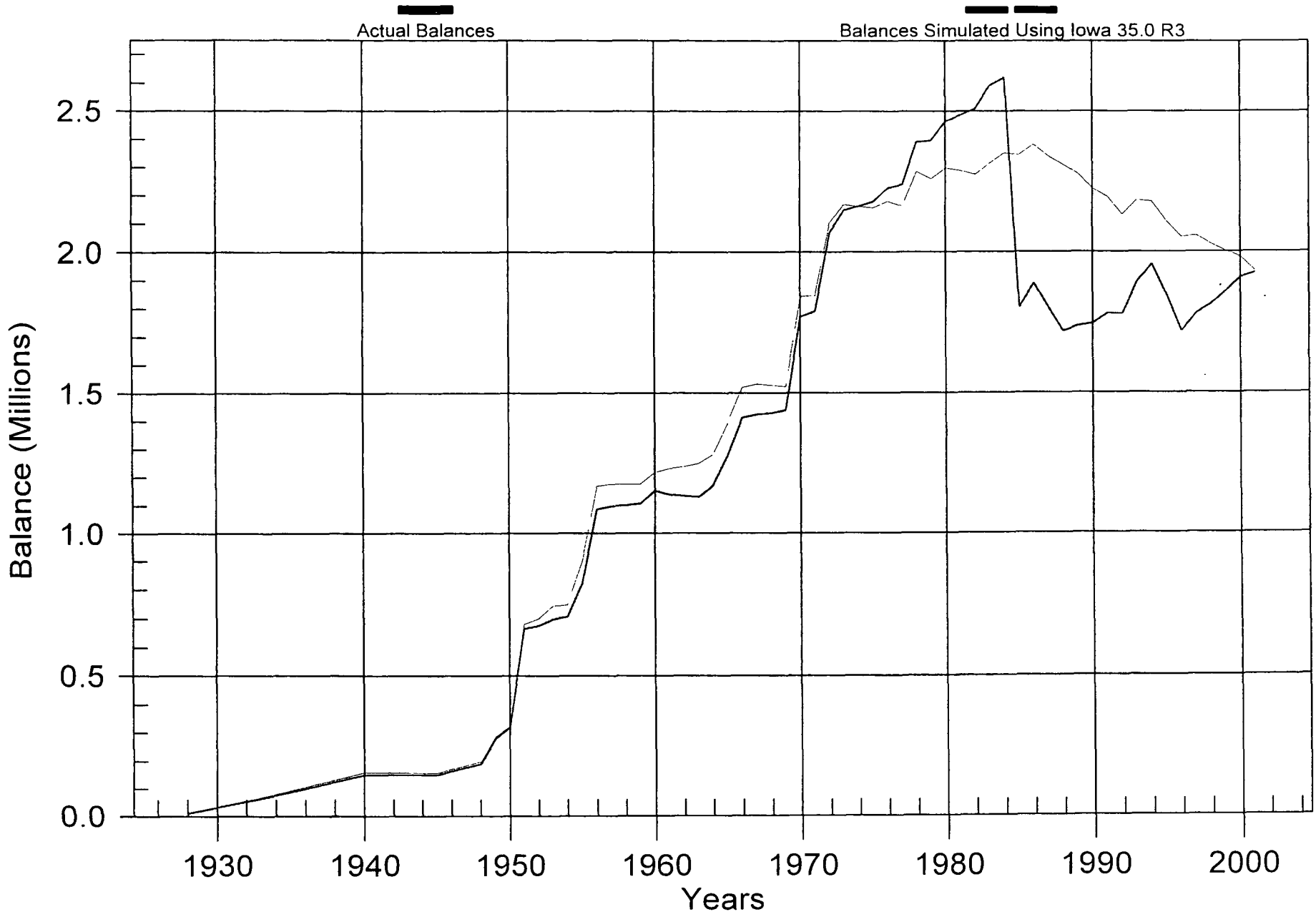


Montana-Dakota Utilities Company

Gas Division

390.00 STRUCTURES & IMPROVEMENTS

Actual And Simulated Balances

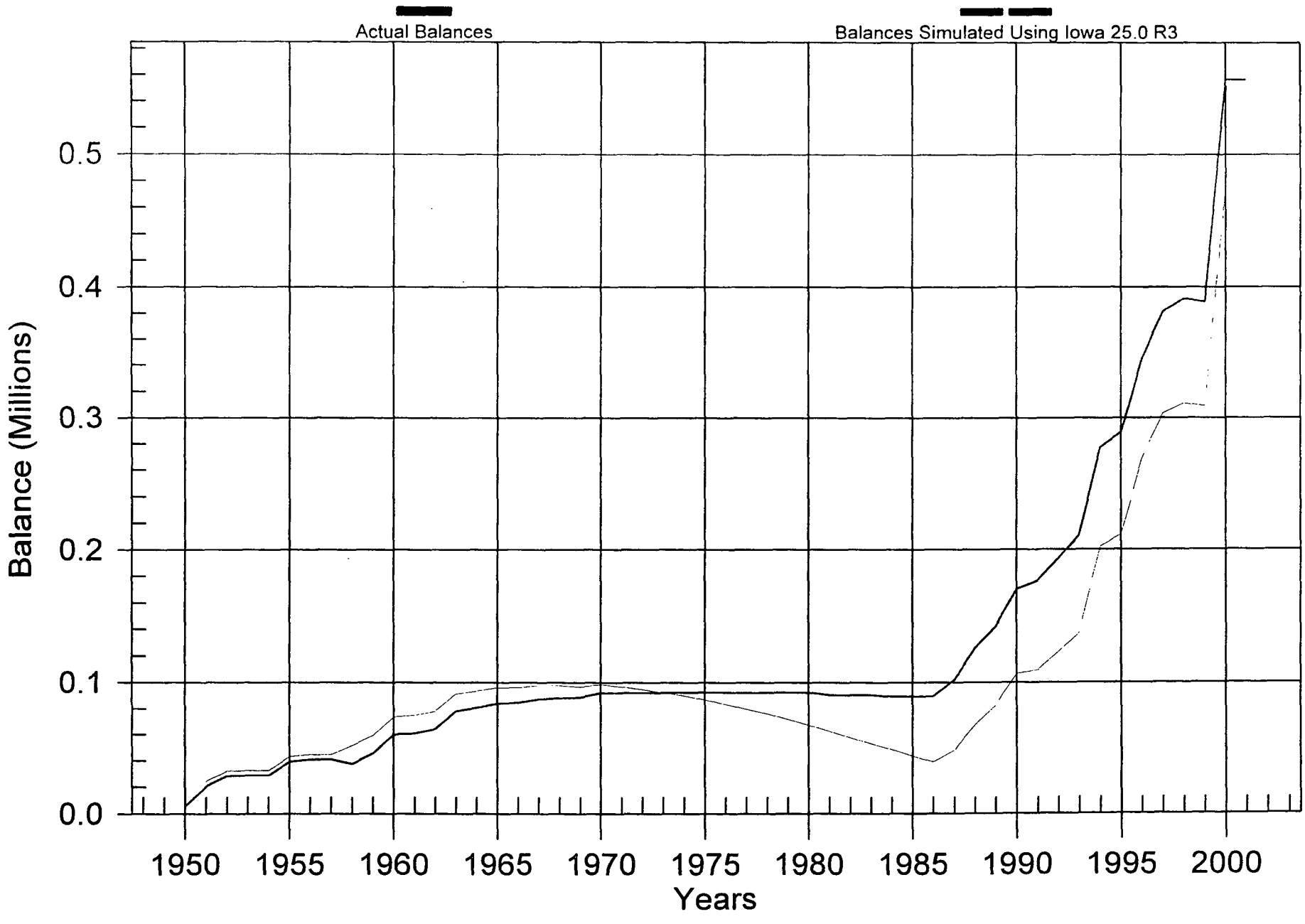


Montana-Dakota Utilities Company

Gas Division

387.20 OTHER DISTRIBUTION EQUIP.

Actual And Simulated Balances



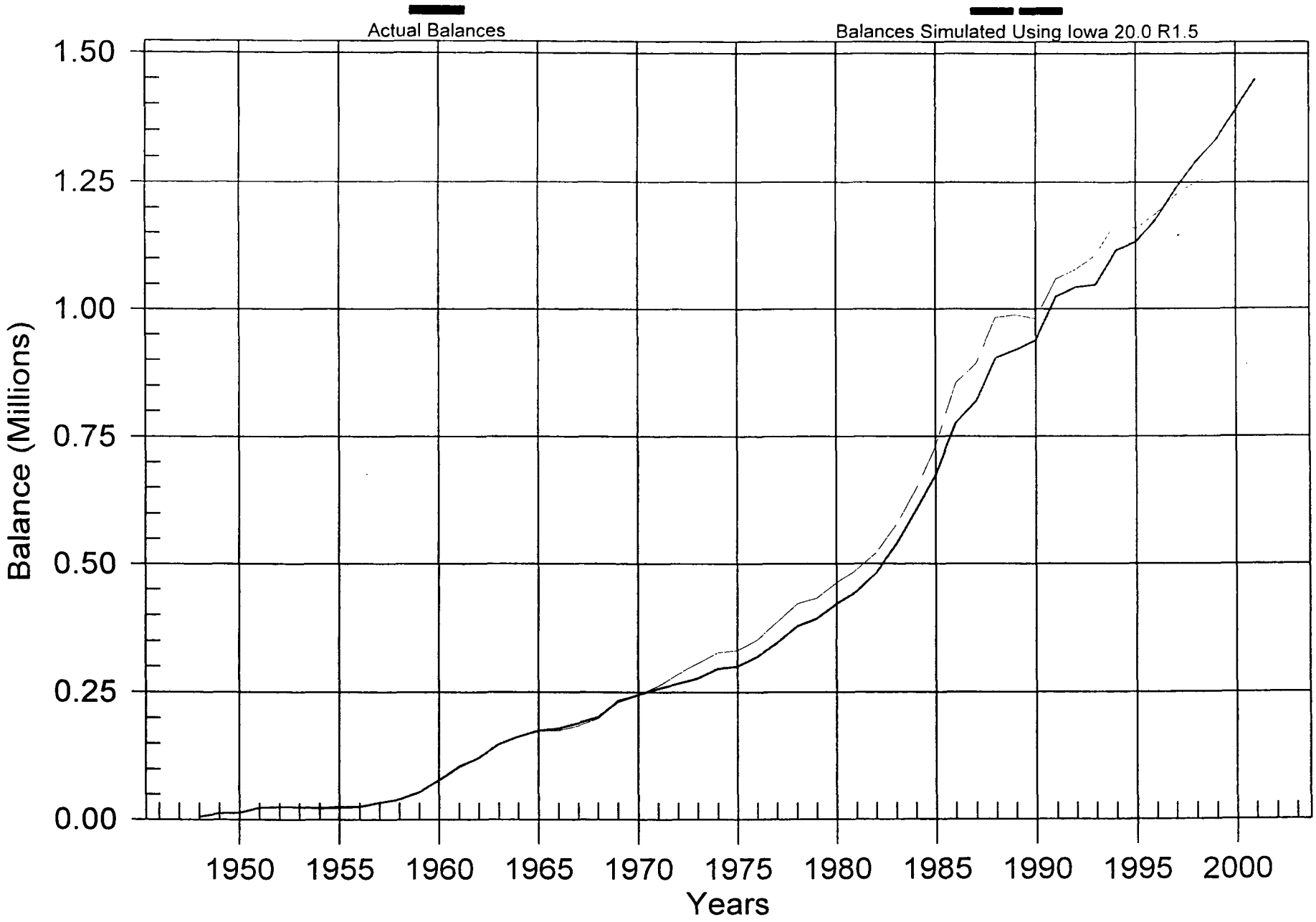
5-12

Montana-Dakota Utilities Company

Gas Division

387.10 CATHODIC PROTECTION EQUIP.

Actual And Simulated Balances

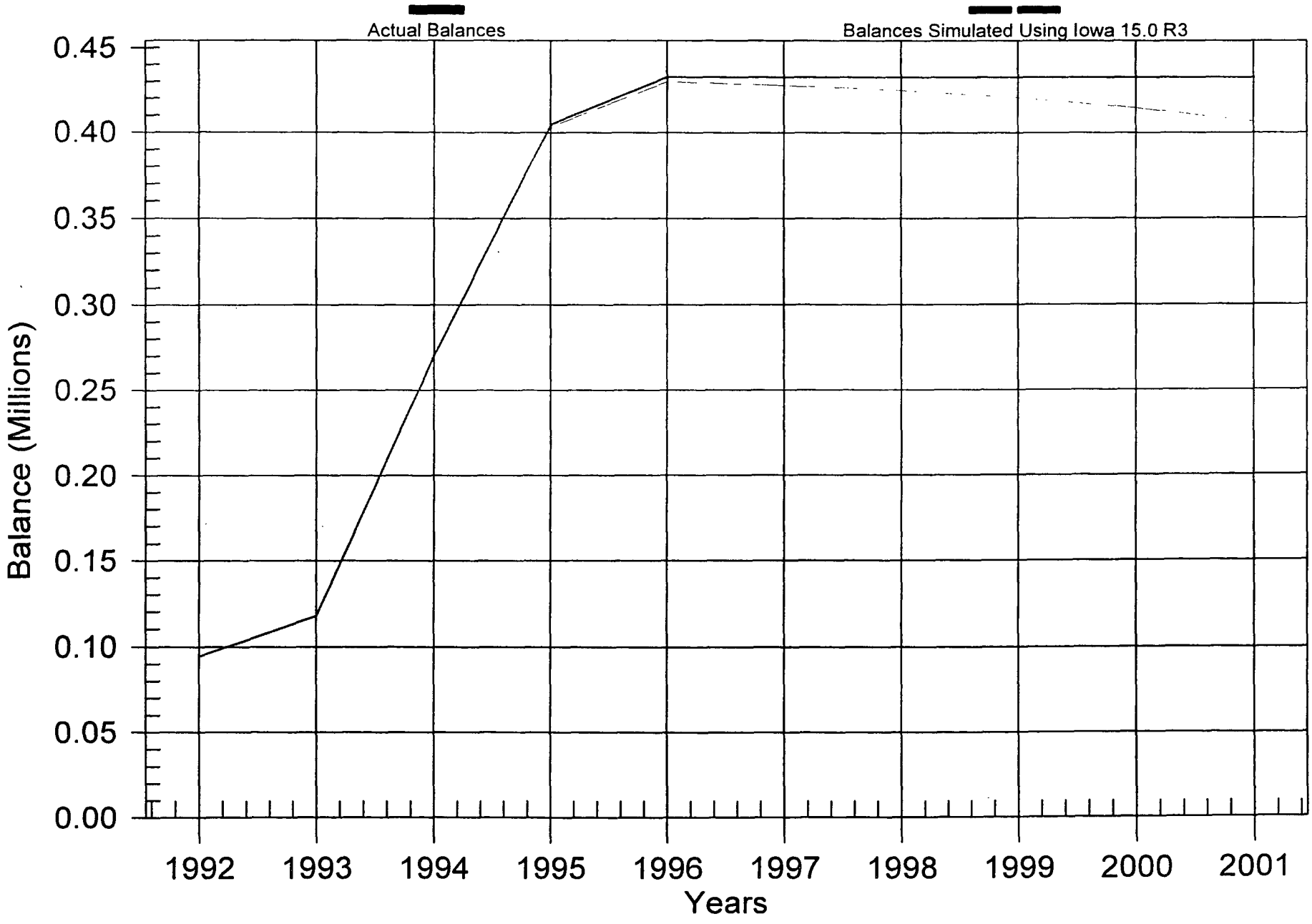


Montana-Dakota Utilities Company

Gas Division

386.20 CNG REFUELING STATIONS

Actual And Simulated Balances



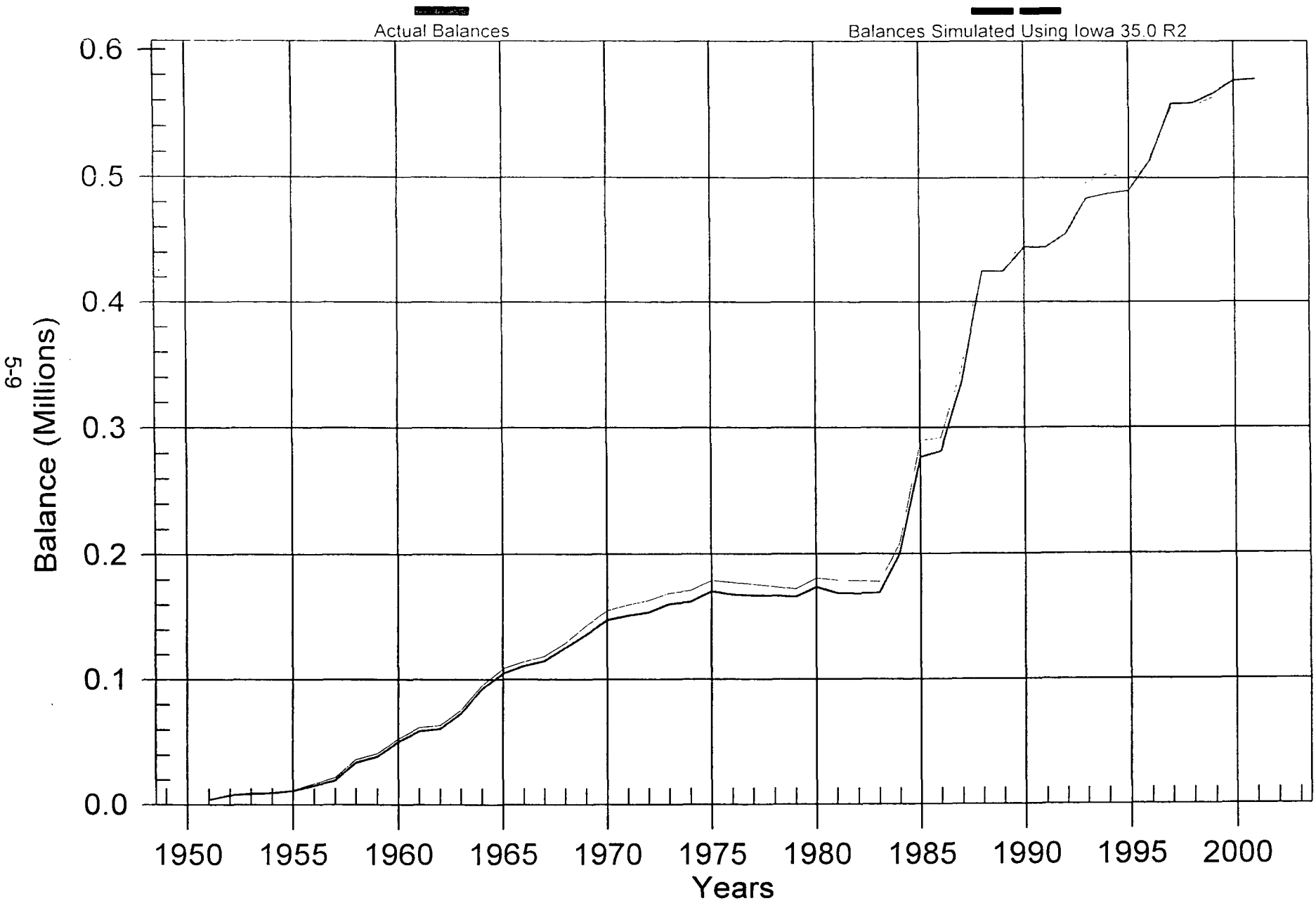
5-10

Montana-Dakota Utilities Company

Gas Division

385.00 IND. MEAS. & REG. STA. EQUIP.

Actual And Simulated Balances

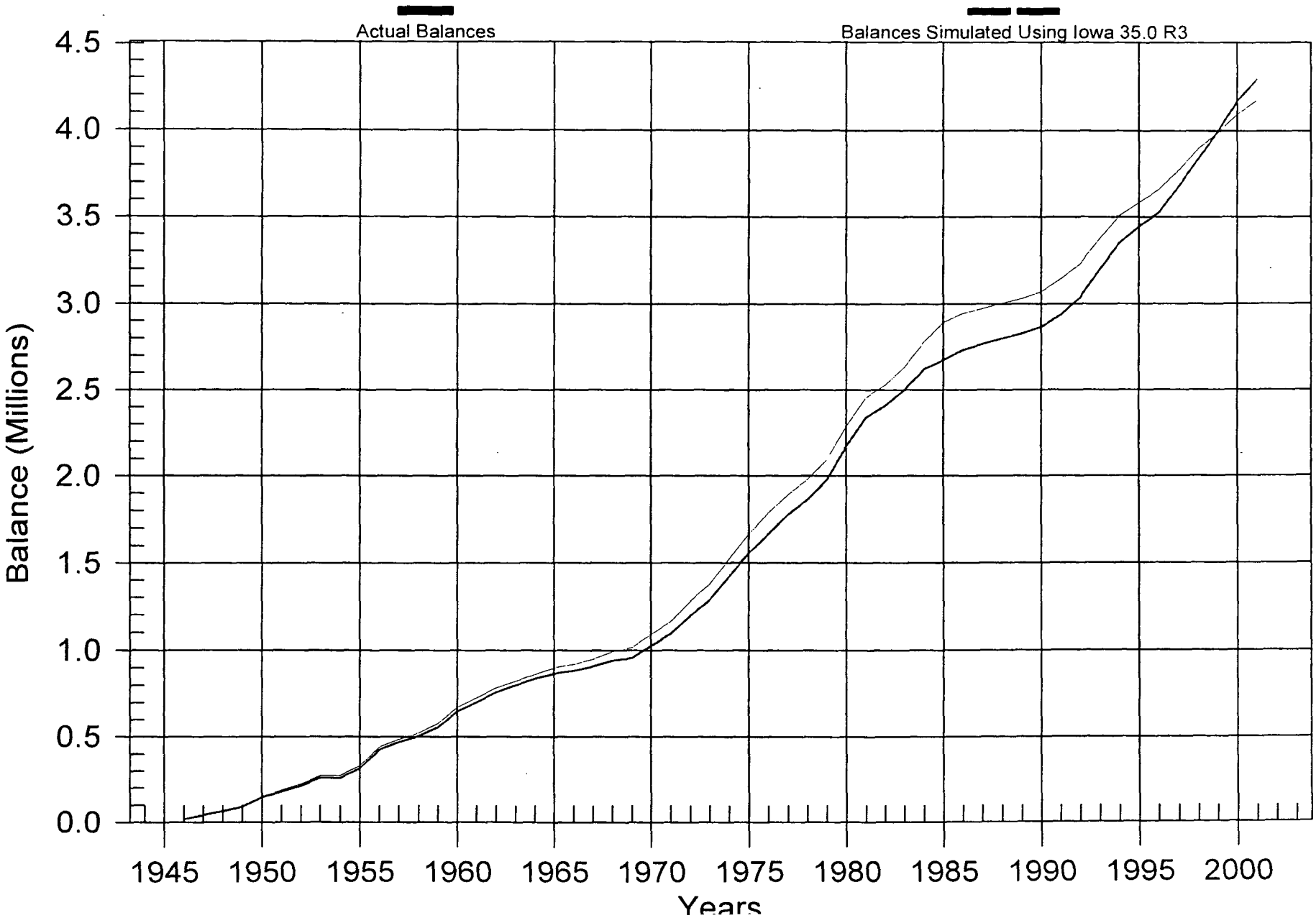


Montana-Dakota Utilities Company

Gas Division

383.00 HOUSE REGULATORS

Actual And Simulated Balances

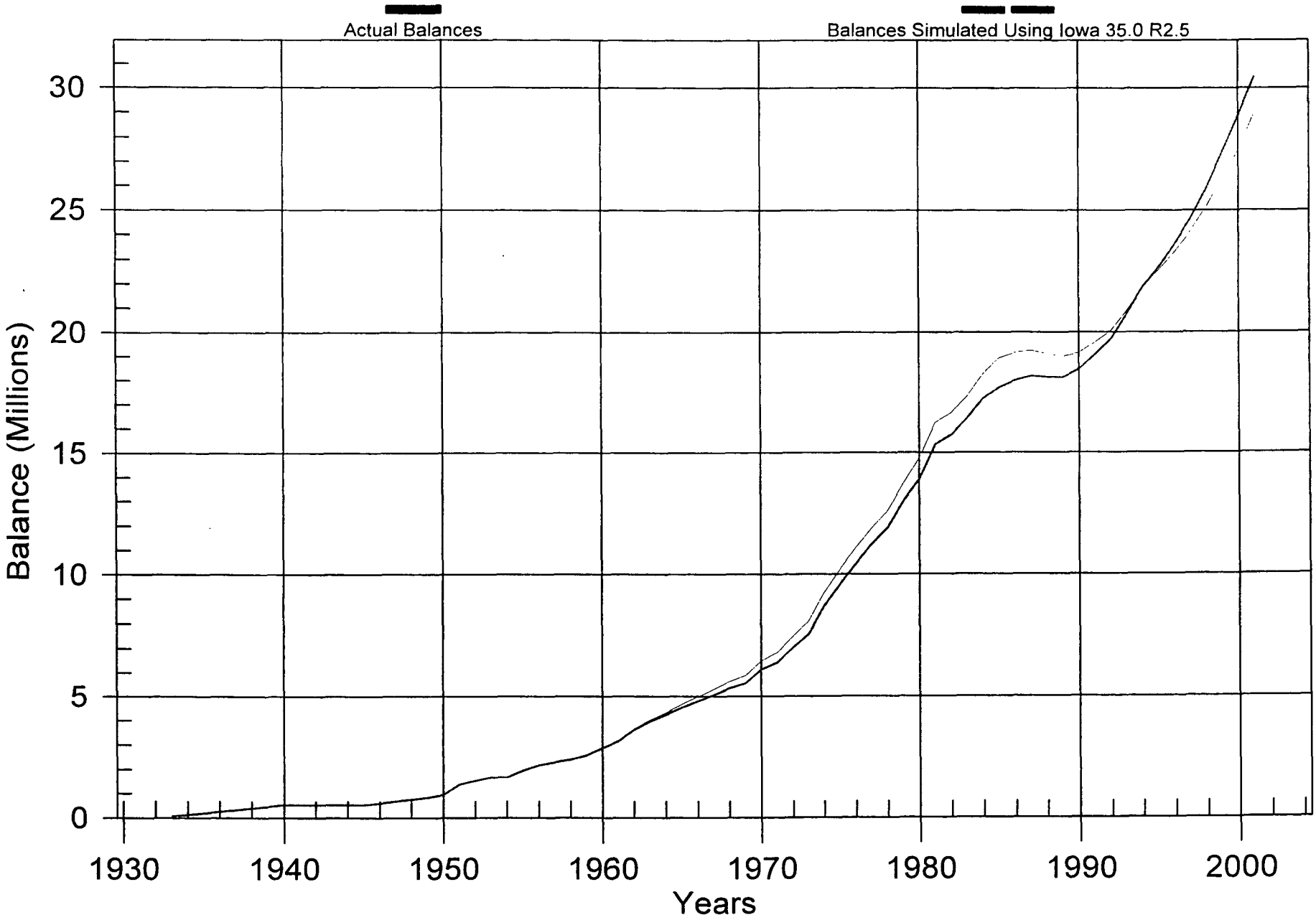


Montana-Dakota Utilities Company

Gas Division

381.00 METERS

Actual And Simulated Balances

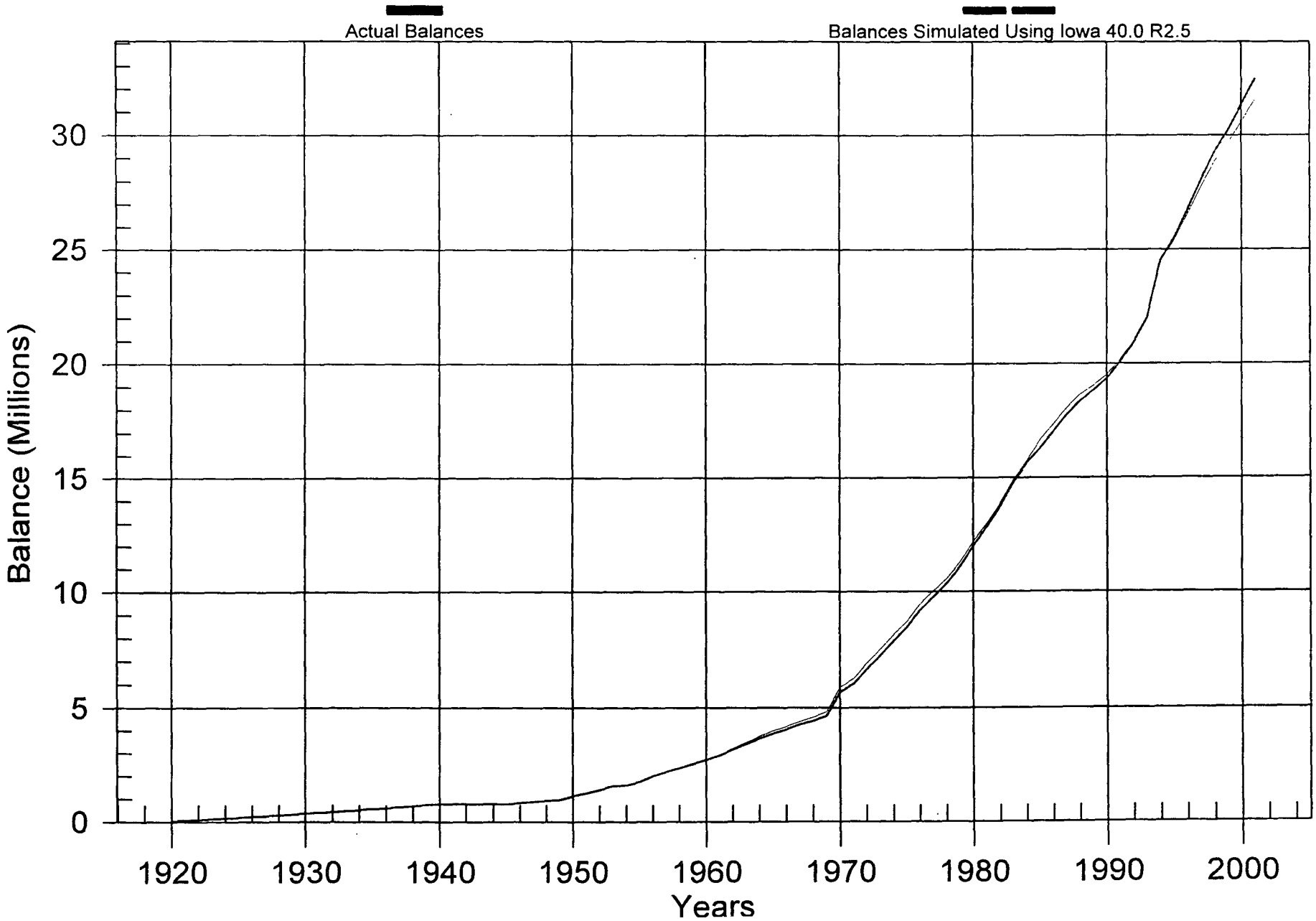


Montana-Dakota Utilities Company

Gas Division

380.00 SERVICES

Actual And Simulated Balances

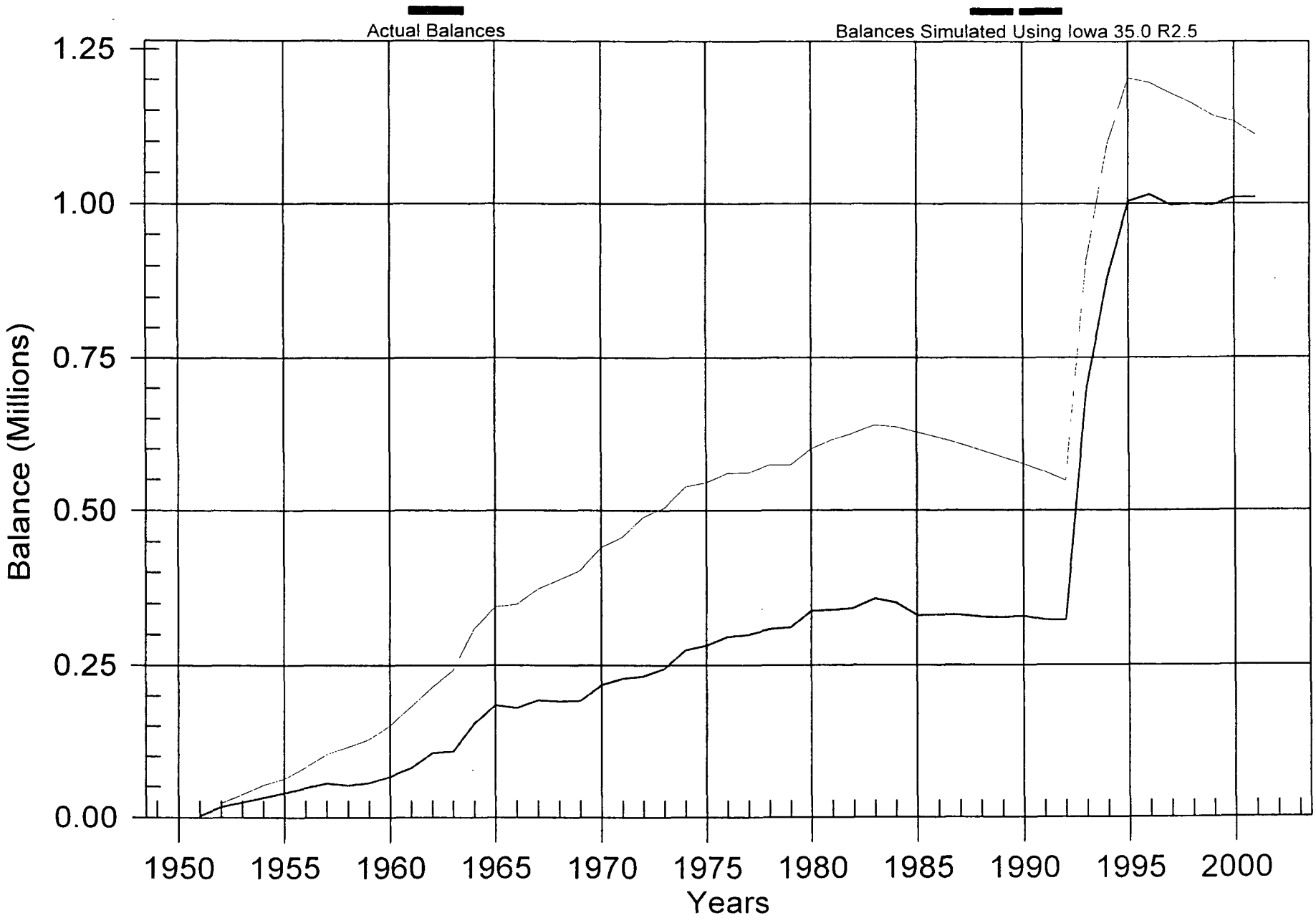


Montana-Dakota Utilities Company

Gas Division

379.00 MEAS. & REG. STATION EQUIP. - CITY GATE

Actual And Simulated Balances

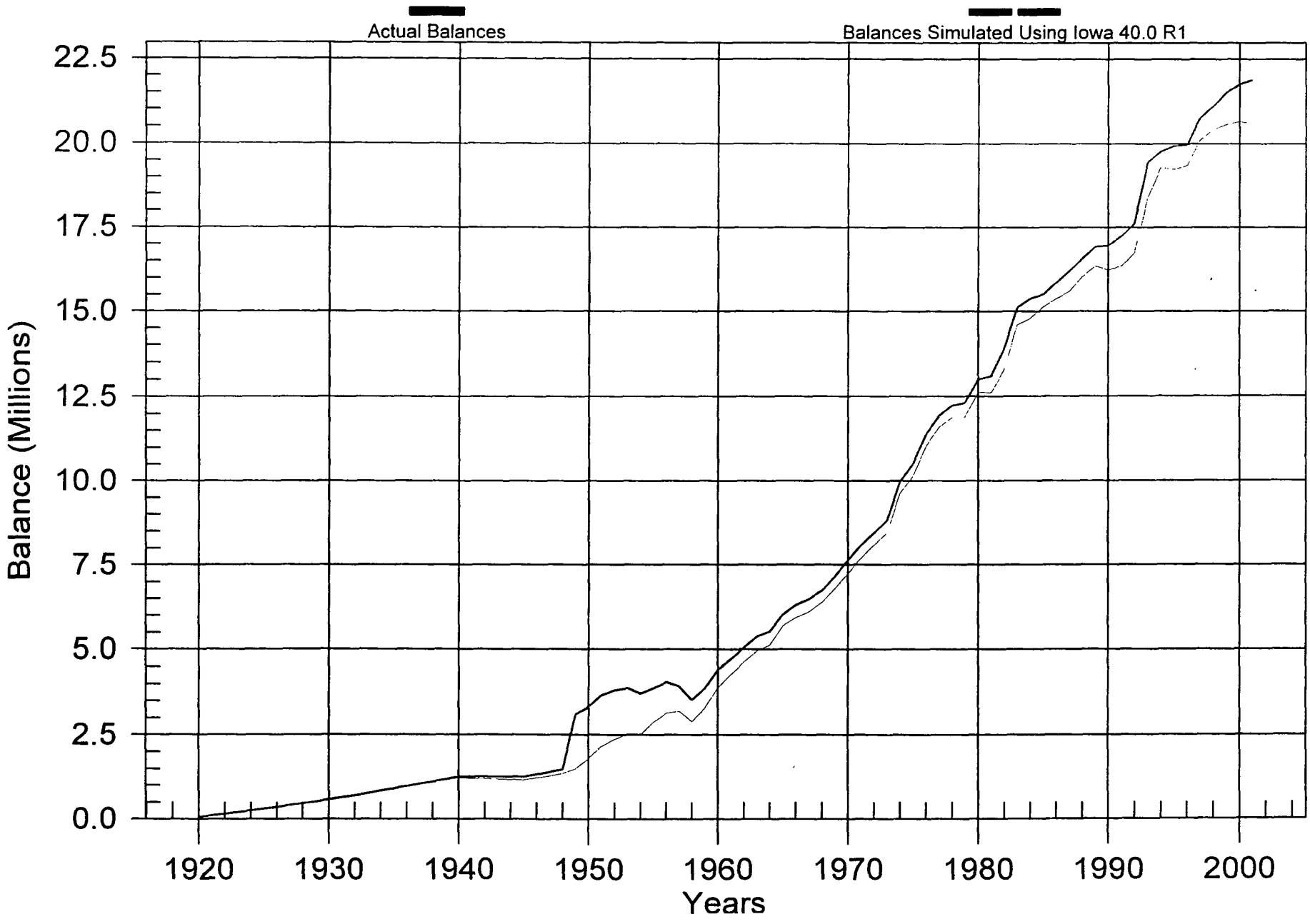


Montana-Dakota Utilities Company

Gas Division

378.00 MEAS. & REG. STATION EQUIP. - GENERAL

Actual And Simulated Balances

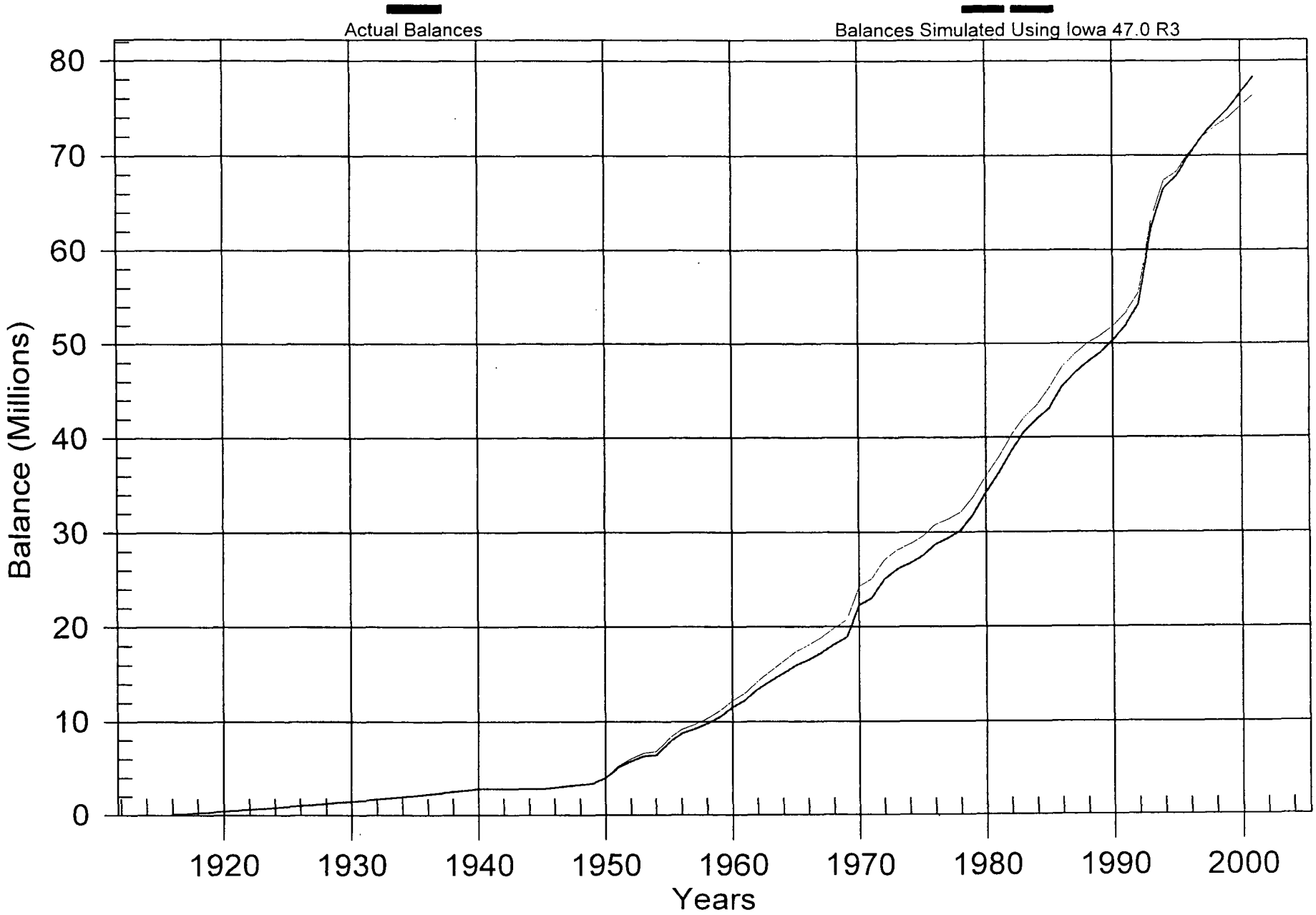


Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Actual And Simulated Balances

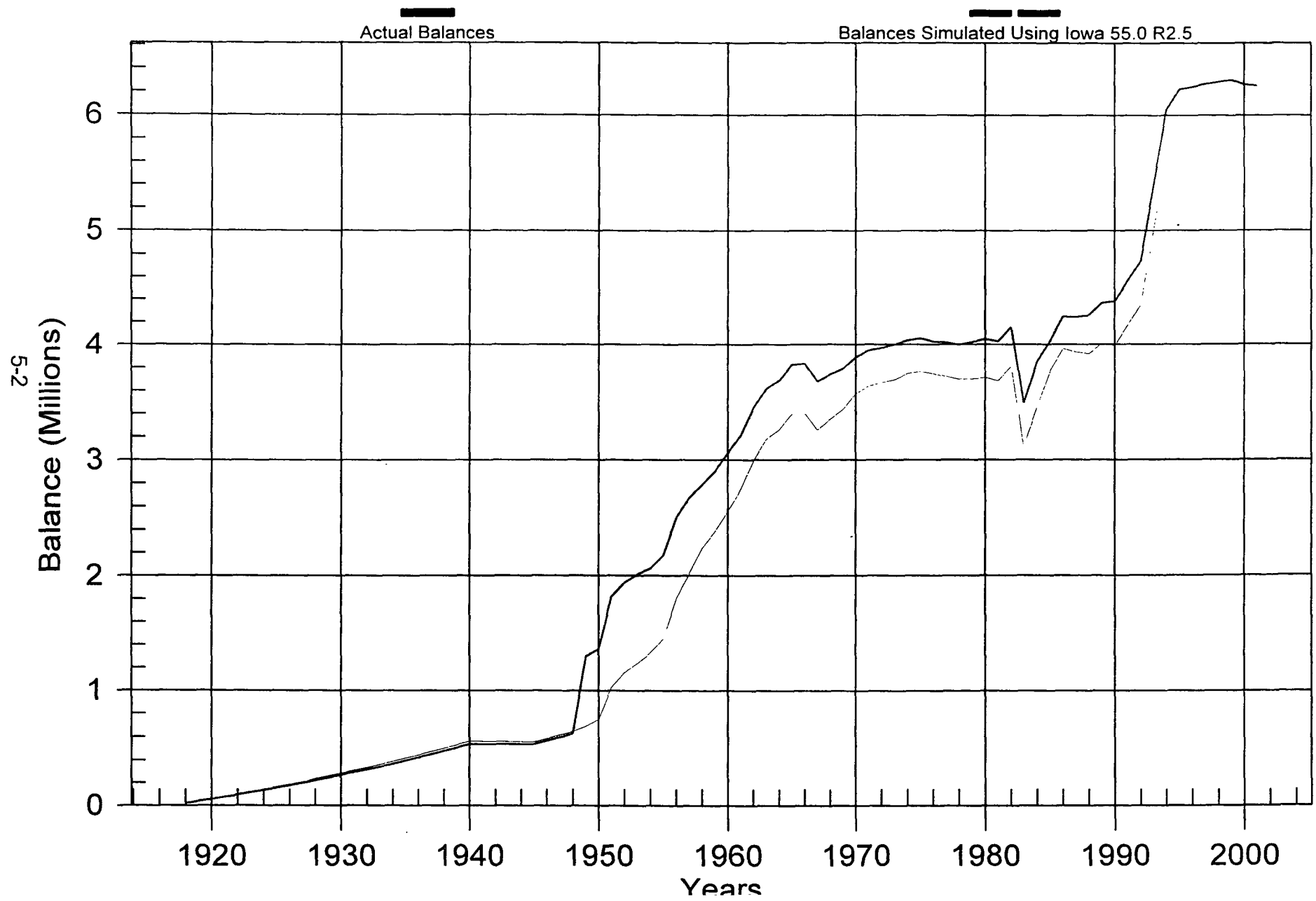


Montana-Dakota Utilities Company

Gas Division

375.00 STRUCTURES & IMPROVEMENTS

Actual And Simulated Balances

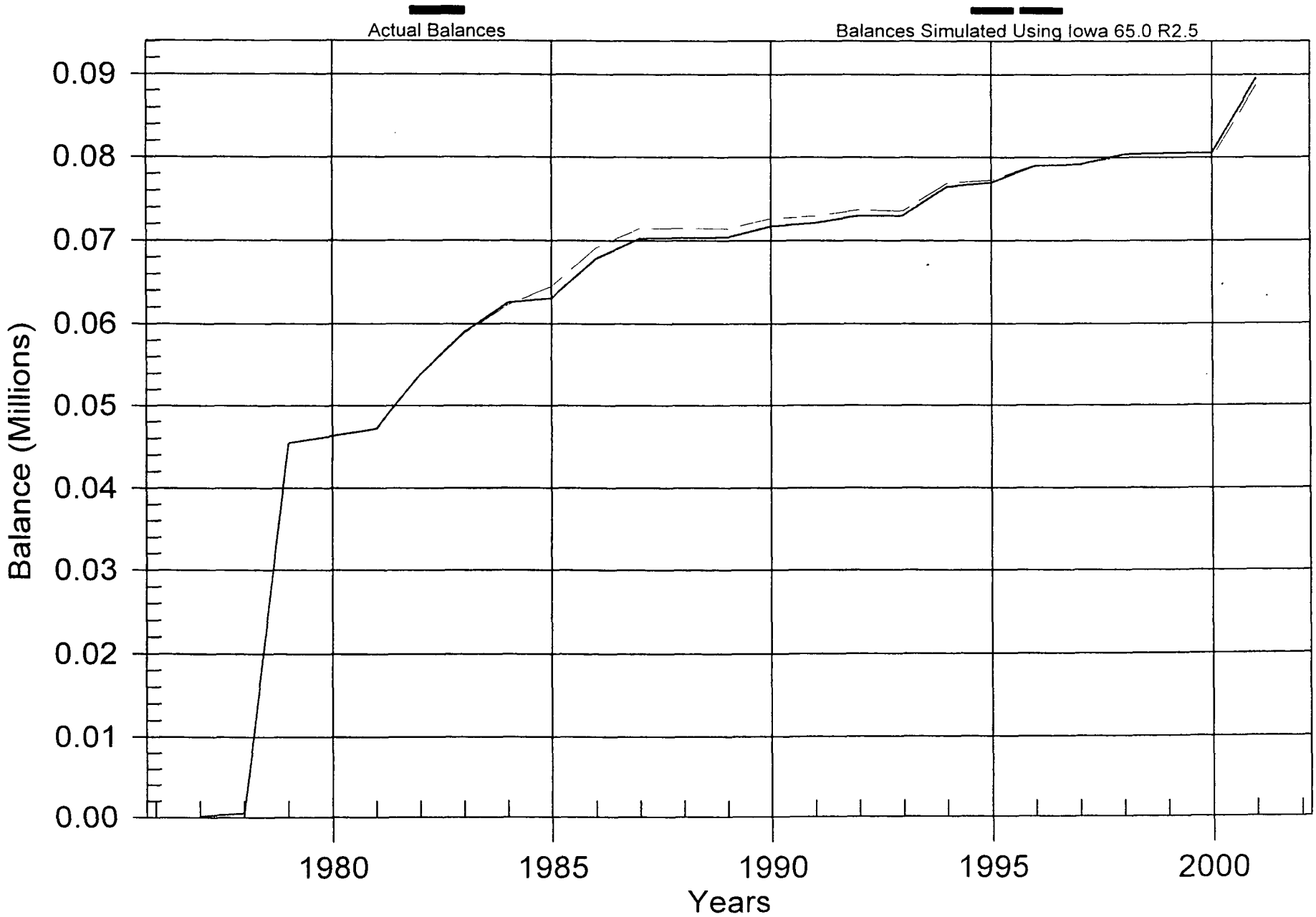


Montana-Dakota Utilities Company

Gas Division

374.20 LAND RIGHTS

Actual And Simulated Balances



Montana-Dakota Utilities Company
Gas Division
374.20 LAND RIGHTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1977	123.99	65.00	1.91	42.95	81.93
1978	368.35	65.00	5.67	43.79	248.18
1979	44,066.18	65.00	677.94	44.64	30,264.98
1980	839.23	65.00	12 91	45.50	587.44
1981	881.80	65.00	13.57	46.36	628.89
1982	6,587.52	65.00	101.35	47.22	4,785.99
1983	4,976.27	65.00	76.56	48.10	3,682.09
1984	3,483.94	65.00	53.60	48.97	2,624.81
1985	2,258.82	65.00	34.75	49.85	1,732.45
1986	4,642.41	65.00	71.42	50.74	3,623.85
1987	2,391.48	65.00	36.79	51.63	1,899.59
1988	101.10	65.00	1.56	52.53	81.70
1989	51.02	65.00	0.78	53.43	41.94
1990	1,320.76	65.00	20.32	54.33	1,103.95
1991	374.95	65.00	5.77	55.24	318.65
1992	867.97	65.00	13.35	56.15	749.81
1994	3,388.39	65.00	52.13	57.99	3,022.90
1995	535.52	65.00	8.24	58.91	485.37
1996	1,977.10	65.00	30.42	59.84	1,820.19
1997	120.38	65.00	1.85	60.77	112.55
1998	1,199.88	65.00	18.46	61.71	1,139.09
1999	165.40	65.00	2.54	62.64	159.40
2001	8,918.56	65.00	137.21	64.53	8,853.68
Total	89,641.02	65.00	1,379.09	49.34	68,049.42

Composite Average Remaining Life ... 49.34 Years

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 55 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1918	2,630.15	55.00	47.82	4.72	225.94
1919	2,695.92	55.00	49.02	4.94	242.09
1920	2,763.33	55.00	50.24	5.16	259.05
1921	2,832.42	55.00	51.50	5.38	276.86
1922	2,903.24	55.00	52.79	5.61	296.05
1923	2,975.83	55.00	54.11	5.83	315.42
1924	3,050.23	55.00	55.46	6.06	335.81
1925	3,126.49	55.00	56.85	6.29	357.27
1926	3,204.66	55.00	58.27	6.52	379.84
1927	3,284.78	55.00	59.72	6.76	403.57
1928	3,366.90	55.00	61.22	7.01	428.83
1929	3,451.07	55.00	62.75	7.25	454.87
1930	3,537.34	55.00	64.32	7.50	482.33
1931	3,625.78	55.00	65.92	7.76	511.34
1932	3,716.43	55.00	67.57	8.02	541.99
1933	3,809.34	55.00	69.26	8.30	574.69
1934	3,904.57	55.00	70.99	8.58	608.86
1935	4,002.19	55.00	72.77	8.87	645.15
1936	4,102.24	55.00	74.59	9.17	683.69
1937	4,204.80	55.00	76.45	9.48	724.67
1938	4,309.92	55.00	78.36	9.80	768.25
1939	4,417.67	55.00	80.32	10.14	814.66
1940	4,528.11	55.00	82.33	10.49	863.93
1946	4,528.11	55.00	82.33	12.92	1,063.43
1947	4,528.12	55.00	82.33	13.38	1,101.23
1948	4,528.11	55.00	82.33	13.85	1,140.33
1949	3,039.44	55.00	55.26	14.34	792.55

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 55 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1950	2,331.84	55.00	42.40	14.85	629.42
1951	6,640.19	55.00	120.73	15.37	1,855.42
1952	3,198.23	55.00	58.15	15.91	924.90
1953	3,995.26	55.00	72.64	16.46	1,195.50
1954	4,431.74	55.00	80.58	17.02	1,371.74
1955	6,720.47	55.00	122.19	17.60	2,150.78
1956	9,212.93	55.00	167.51	18.20	3,048.11
1957	14,927.15	55.00	271.40	18.80	5,103.70
1958	9,888.08	55.00	179.78	19.43	3,492.42
1959	8,789.86	55.00	159.82	20.06	3,205.72
1960	8,792.17	55.00	159.86	20.70	3,309.69
1961	13,667.30	55.00	248.50	21.36	5,307.61
1962	9,273.89	55.00	168.62	22.03	3,714.26
1963	8,388.55	55.00	152.52	22.71	3,463.36
1964	6,572.87	55.00	119.51	23.40	2,796.22
1965	10,307.87	55.00	187.42	24.10	4,516.46
1966	6,013.01	55.00	109.33	24.81	2,712.10
1967	6,820.87	55.00	124.02	25.53	3,165.92
1968	7,271.54	55.00	132.21	26.26	3,471.70
1969	6,919.56	55.00	125.81	27.00	3,396.73
1970	10,686.74	55.00	194.30	27.75	5,391.51
1971	5,843.70	55.00	106.25	28.51	3,028.69
1972	3,251.79	55.00	59.12	29.27	1,730.58
1973	3,017.55	55.00	54.86	30.05	1,648.47
1974	5,099.88	55.00	92.72	30.83	2,858.74
1975	2,769.58	55.00	50.36	31.62	1,592.37
1979	1,930.29	55.00	35.10	34.87	1,223.76

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 55 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1980	1,962.55	55.00	35.68	35.70	1,273.87
1981	565.11	55.00	10.27	36.54	375.42
1982	10,550.16	55.00	191.82	37.38	7,170.89
1983	1,529.33	55.00	27.81	38.23	1,063.14
1984	25,576.47	55.00	465.03	39.09	18,179.43
1985	24,940.51	55.00	453.46	39.96	18,119.89
1986	15,715.33	55.00	285.73	40.83	11,666.65
1987	491.04	55.00	8.93	41.71	372.37
1988	1,407.56	55.00	25.59	42.59	1,089.99
1989	9,008.67	55.00	163.79	43.48	7,121.87
1990	1,672.59	55.00	30.41	44.38	1,349.50
1991	15,439.21	55.00	280.71	45.28	12,709.61
1992	15,587.57	55.00	283.41	46.18	13,088.34
1993	49,564.00	55.00	901.16	47.09	42,437.48
1994	49,273.17	55.00	895.87	48.01	43,007.54
1996	3,855.73	55.00	70.10	49.85	3,494.69
1997	6,640.54	55.00	120.74	50.78	6,130.78
1998	1,293.36	55.00	23.52	51.71	1,215.99
1999	1,737.43	55.00	31.59	52.65	1,663.04
2000	569.81	55.00	10.36	53.58	555.14
Total	521,210.24	55.00	9,476.53	29.94	283,684.21

Composite Average Remaining Life ... 29.94 Years

Montana-Dakota Utilities Company
Gas Division
376.10 MAINS - STEEL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1926	0.46	45.00	0.01	0.50	0.01
1927	7.90	45.00	0.18	0.54	0.09
1928	37.89	45.00	0.84	0.68	0.57
1929	111.24	45.00	2.47	0.91	2.25
1930	253.98	45.00	5.64	1.14	6.42
1931	493.63	45.00	10.97	1.37	15.03
1932	856.11	45.00	19.02	1.59	30.23
1933	1,369.83	45.00	30.44	1.84	55.96
1934	2,064.35	45.00	45.87	2.09	95.90
1935	2,979.79	45.00	66.22	2.34	155.28
1936	4,142.79	45.00	92.06	2.60	239.48
1937	5,589.93	45.00	124.22	2.84	353.36
1938	7,360.90	45.00	163.58	3.10	507.64
1939	9,505.32	45.00	211.23	3.36	710.21
1940	12,069.90	45.00	268.22	3.62	971.28
1946	33,260.85	45.00	739.13	5.21	3,853.93
1947	37,960.11	45.00	843.56	5.51	4,645.28
1948	42,934.21	45.00	954.09	5.81	5,544.73
1949	49,410.04	45.00	1,098.00	6.13	6,730.65
1950	226,630.30	45.00	5,036.23	6.46	32,542.32
1951	481,470.34	45.00	10,699.33	6.81	72,883.97
1952	306,423.81	45.00	6,809.41	7.18	48,893.45
1953	276,769.47	45.00	6,150.43	7.57	46,542.27
1954	87,775.92	45.00	1,950.57	7.97	15,553.68
1955	747,194.20	45.00	16,604.31	8.40	139,509.68
1956	550,540.11	45.00	12,234.22	8.85	108,274.50
1957	325,394.39	45.00	7,230.98	9.32	67,386.75

Montana-Dakota Utilities Company

Gas Division

376.10 MAINS - STEEL

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1958	431,107.00	45.00	9,580.15	9.81	93,973.41
1959	553,122.71	45.00	12,291.61	10.32	126,880.52
1960	732,597.62	45.00	16,279.94	10.86	176,720.51
1961	636,569.71	45.00	14,145.99	11.41	161,378.09
1962	936,723.36	45.00	20,816.06	11.98	249,395.13
1963	884,989.06	45.00	19,666.41	12.57	247,268.33
1964	839,286.79	45.00	18,650.81	13.19	245,956.55
1965	870,931.68	45.00	19,354.03	13.82	267,422.61
1966	610,660.47	45.00	13,570.22	14.46	196,289.78
1967	857,538.32	45.00	19,056.40	15.13	288,299.36
1968	1,051,320.08	45.00	23,362.65	15.81	369,393.67
1969	962,546.26	45.00	21,389.90	16.51	353,092.28
1970	3,244,082.74	45.00	72,090.69	17.22	1,241,273.09
1971	797,467.90	45.00	17,721.50	17.94	317,978.74
1972	831,037.98	45.00	18,467.50	18.68	345,002.24
1973	911,086.63	45.00	20,246.36	19.44	393,503.74
1974	450,583.23	45.00	10,012.95	20.20	202,269.17
1975	69,798.16	45.00	1,551.07	20.98	32,538.33
1976	733,622.14	45.00	16,302.70	21.77	354,864.51
1977	402,611.06	45.00	8,946.91	22.57	201,931.49
1978	399,496.10	45.00	8,877.69	23.38	207,585.64
1979	696,362.97	45.00	15,474.72	24.21	374,593.68
1980	850,615.59	45.00	18,902.56	25.04	473,350.07
1981	1,026,692.11	45.00	22,815.37	25.89	590,620.12
1982	1,222,659.70	45.00	27,170.20	26.74	726,652.99
1983	978,065.89	45.00	21,734.78	27.61	600,111.78
1984	321,413.35	45.00	7,142.51	28.49	203,465.45

Montana-Dakota Utilities Company

Gas Division

376.10 MAINS - STEEL

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1985	838,322.58	45.00	18,629.38	29.37	547,178.00
1986	1,271,814.28	45.00	28,262.52	30.27	855,432.38
1987	366,675.95	45.00	8,148.35	31.17	253,990.46
1988	571,181.31	45.00	12,692.91	32.08	407,220.11
1989	488,132.96	45.00	10,847.39	33.00	357,986.60
1990	455,212.65	45.00	10,115.83	33.93	343,222.07
1991	545,918.18	45.00	12,131.51	34.86	422,959.63
1992	634,284.39	45.00	14,095.20	35.81	504,688.70
1993	1,167,286.50	45.00	25,939.68	36.75	953,363.33
1994	385,982.98	45.00	8,577.39	37.71	323,421.32
1995	93,676.43	45.00	2,081.70	38.67	80,489.75
1996	184,525.08	45.00	4,100.55	39.63	162,501.34
1997	112,135.50	45.00	2,491.90	40.60	101,164.27
1998	267,853.04	45.00	5,952.29	41.57	247,433.77
1999	419,826.94	45.00	9,329.48	42.55	396,927.74
2000	417,773.20	45.00	9,283.84	43.53	404,082.54
2001	112,871.05	45.00	2,508.24	44.51	111,636.41
Total	33,849,069.40	45.00	752,201.11	21.37	16,071,014.60

Composite Average Remaining Life ... 21.37 Years

Montana-Dakota Utilities Company
Gas Division
376.20 MAINS - PLASTIC
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1970	376,595.78	45.00	8,368.79	17.22	144,095.65
1971	144,804.26	45.00	3,217.87	17.94	57,738.59
1972	1,297,016.85	45.00	28,822.58	18.68	538,451.58
1973	299,374.48	45.00	6,652.76	19.44	129,301.62
1974	241,086.49	45.00	5,357.47	20.20	108,224.99
1975	894,989.19	45.00	19,888.64	20.98	417,223.86
1976	659,925.68	45.00	14,665.01	21.77	319,216.38
1977	324,341.06	45.00	7,207.57	22.57	162,674.80
1978	525,534.89	45.00	11,678.55	23.38	273,077.75
1979	1,118,014.33	45.00	24,844.75	24.21	601,412.08
1980	1,530,214.91	45.00	34,004.76	25.04	851,533.10
1981	1,159,108.23	45.00	25,757.95	25.89	666,794.49
1982	1,163,169.54	45.00	25,848.20	26.74	691,296.71
1983	1,182,122.34	45.00	26,269.37	27.61	725,314.67
1984	1,267,929.23	45.00	28,176.19	28.49	802,641.82
1985	1,280,656.53	45.00	28,459.02	29.37	835,891.94
1986	1,208,207.48	45.00	26,849.04	30.27	812,649.94
1987	1,272,224.15	45.00	28,271.63	31.17	881,248.95
1988	799,348.47	45.00	17,763.29	32.08	569,890.45
1989	625,863.79	45.00	13,908.08	33.00	458,995.53
1990	918,177.66	45.00	20,403.94	33.93	692,289.27
1991	1,282,397.31	45.00	28,497.70	34.86	993,559.67
1992	1,920,024.13	45.00	42,667.18	35.81	1,527,728.72
1993	6,817,223.98	45.00	151,493.78	36.75	5,567,863.01
1994	4,272,376.85	45.00	94,941.65	37.71	3,579,893.02
1995	1,272,617.52	45.00	28,280.37	38.67	1,093,473.19
1996	2,332,294.70	45.00	51,828.74	39.63	2,053,926.81

Montana-Dakota Utilities Company

Gas Division

376.20 MAINS - PLASTIC

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1997	1,996,631.35	45.00	44,369.56	40.60	1,801,282.90
1998	1,493,127.53	45.00	33,180.59	41.57	1,379,301.78
1999	1,087,269.93	45.00	24,161.54	42.55	1,027,965.46
2000	1,506,913.52	45.00	33,486.95	43.53	1,457,531.13
2001	1,743,393.04	45.00	38,742.05	44.51	1,724,322.87
Total	44,012,975.20	45.00	978,065.55	33.69	32,946,812.75

Composite Average Remaining Life ... 33.69 Years

Montana-Dakota Utilities Company
Gas Division
376.30 MAINS - VALVES
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1977	1,442.20	40.00	36.05	19.00	684.99
1978	3,373.98	40.00	84.35	19.74	1,664.81
1979	8,309.96	40.00	207.75	20.49	4,256.73
1980	3,512.48	40.00	87.81	21.25	1,866.30
1981	2,710.94	40.00	67.77	22.03	1,493.06
1982	10,041.69	40.00	251.04	22.82	5,728.08
1983	1,791.09	40.00	44.78	23.62	1,057.49
1984	8,052.13	40.00	201.30	24.43	4,917.03
1985	38,658.45	40.00	966.46	25.25	24,400.31
1986	10,734.69	40.00	268.37	26.08	6,998.27
1987	28,426.45	40.00	710.66	26.92	19,129.89
1988	24,014.92	40.00	600.37	27.77	16,671.26
1989	8,493.27	40.00	212.33	28.63	6,078.67
1990	5,192.49	40.00	129.81	29.50	3,828.95
1991	3,640.35	40.00	91.01	30.37	2,764.25
1992	13,194.19	40.00	329.85	31.26	10,310.62
1993	142,145.32	40.00	3,553.62	32.15	114,253.87
1994	17,817.20	40.00	445.43	33.05	14,721.94
1995	4,300.00	40.00	107.50	33.96	3,650.55
1997	5,405.53	40.00	135.14	35.79	4,836.92
1999	36,828.93	40.00	920.72	37.65	34,664.93
2000	8,767.06	40.00	219.18	38.59	8,457.14
2001	4,650.56	40.00	116.26	39.53	4,595.64
Total	391,503.88	40.00	9,787.56	30.35	297,031.71

Composite Average Remaining Life ... 30.35 Years

Montana-Dakota Utilities Company

Gas Division

376.40 MAINS - MANHOLES

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1960	9.90	45.00	0.22	10.86	2.39
1978	3,706.52	45.00	82.37	23.38	1,925.98
1979	1,211.43	45.00	26.92	24.21	651.66
1980	7,430.06	45.00	165.11	25.04	4,134.68
1981	4,708.73	45.00	104.64	25.89	2,708.77
1982	10,590.76	45.00	235.35	26.74	6,294.32
1983	4,593.08	45.00	102.07	27.61	2,818.18
1984	2,952.00	45.00	65.60	28.49	1,868.72
1985	5,397.11	45.00	119.94	29.37	3,522.72
1986	1,716.97	45.00	38.15	30.27	1,154.85
1987	3,512.13	45.00	78.05	31.17	2,432.80
1988	3,739.38	45.00	83.10	32.08	2,665.97
1990	9,279.86	45.00	206.22	33.93	6,996.85
1991	1,140.52	45.00	25.34	34.86	883.64
1993	4,344.30	45.00	96.54	36.75	3,548.14
1995	2,299.05	45.00	51.09	38.67	1,975.42
1996	3,287.49	45.00	73.06	39.63	2,895.12
Total	69,919.29	45.00	1,553.76	29.91	46,480.17

Composite Average Remaining Life ... 29.91 Years

Montana-Dakota Utilities Company
Gas Division
376.50 MAINS - BRIDGE & RIVER CROSSINGS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1995	8,923.21	45.00	198.29	38.67	7,667.10
1996	39.60	45.00	0.88	39.63	34.87
1998	1,723.00	45.00	38.29	41.57	1,591.65
Total	10,685.81	45.00	237.46	39.14	9,293.63

Composite Average Remaining Life ... 39.14 Years

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R1*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1920	4,480.53	0.00	0.00	0.00	0.00
1921	4,592.56	0.00	0.00	0.00	0.00
1922	4,707.38	40.00	117.68	0.50	58.84
1923	4,825.08	40.00	120.62	0.69	83.14
1924	4,945.71	40.00	123.64	1.01	124.46
1925	5,069.36	40.00	126.73	1.32	167.40
1926	5,196.10	40.00	129.90	1.66	215.34
1927	5,326.01	40.00	133.15	1.99	264.46
1928	5,459.15	40.00	136.47	2.31	315.62
1929	5,595.63	40.00	139.89	2.62	365.92
1930	5,735.52	40.00	143.38	2.92	418.60
1931	5,878.91	40.00	146.97	3.21	471.90
1932	6,025.88	40.00	150.64	3.51	528.60
1933	6,176.53	40.00	154.41	3.80	587.08
1934	6,330.94	40.00	158.27	4.10	649.54
1935	6,489.22	40.00	162.23	4.40	714.58
1936	6,651.45	40.00	166.28	4.71	784.00
1937	6,817.73	40.00	170.44	5.03	856.60
1938	6,988.18	40.00	174.70	5.35	933.91
1939	7,162.89	40.00	179.07	5.67	1,014.97
1940	7,341.96	40.00	183.54	6.00	1,101.07
1946	7,341.96	40.00	183.54	8.10	1,487.14
1947	7,341.96	40.00	183.54	8.47	1,555.47
1948	7,341.97	40.00	183.54	8.85	1,625.19
1949	7,341.96	40.00	183.54	9.24	1,696.00
1950	11,294.20	40.00	282.35	9.63	2,720.04
1951	17,199.91	40.00	429.99	10.03	4,314.29

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R1*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1952	11,030.43	40.00	275.75	10.44	2,879.13
1953	7,808.82	40.00	195.22	10.86	2,119.14
1954	435.50	40.00	10.89	11.28	122.78
1955	11,128.61	40.00	278.21	11.71	3,256.96
1956	8,344.71	40.00	208.61	12.14	2,533.40
1957	4,272.99	40.00	106.82	12.59	1,344.80
1958	4,408.33	40.00	110.21	13.04	1,437.30
1959	19,477.47	40.00	486.92	13.50	6,575.08
1960	30,297.34	40.00	757.41	13.97	10,582.83
1961	20,034.43	40.00	500.85	14.45	7,237.33
1962	18,363.33	40.00	459.07	14.94	6,856.62
1963	17,287.20	40.00	432.17	15.43	6,668.64
1964	10,252.25	40.00	256.30	15.93	4,083.71
1965	28,503.26	40.00	712.56	16.45	11,718.41
1966	14,515.53	40.00	362.88	16.97	6,156.41
1967	11,176.95	40.00	279.42	17.50	4,888.40
1968	16,224.95	40.00	405.61	18.03	7,314.22
1969	22,887.68	40.00	572.18	18.58	10,630.82
1970	24,336.64	40.00	608.40	19.13	11,641.44
1971	25,065.48	40.00	626.62	19.70	12,343.81
1972	22,588.57	40.00	564.70	20.27	11,447.12
1973	20,531.20	40.00	513.27	20.85	10,703.02
1974	59,221.16	40.00	1,480.49	21.44	31,744.30
1975	29,712.79	40.00	742.80	22.04	16,371.23
1976	47,450.98	40.00	1,186.24	22.65	26,862.58
1977	31,886.44	40.00	797.14	23.26	18,540.67
1978	19,707.84	40.00	492.68	23.88	11,765.02

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R1*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1979	6,827.69	40.00	170.69	24.51	4,183.24
1980	40,384.22	40.00	1,009.58	25.14	25,383.70
1981	6,436.72	40.00	160.91	25.79	4,149.17
1982	39,010.46	40.00	975.23	26.43	25,778.03
1983	68,082.28	40.00	1,702.01	27.09	46,102.22
1984	17,673.03	40.00	441.81	27.75	12,258.53
1985	24,974.90	40.00	624.36	28.41	17,738.43
1986	20,354.92	40.00	508.86	29.08	14,797.48
1987	19,334.97	40.00	483.36	29.75	14,381.79
1988	30,555.06	40.00	763.86	30.43	23,245.04
1989	24,628.52	40.00	615.70	31.11	19,156.25
1990	5,102.42	40.00	127.56	31.80	4,056.09
1991	16,006.63	40.00	400.15	32.49	13,000.09
1992	28,866.49	40.00	721.64	33.18	23,944.36
1993	87,938.23	40.00	2,198.40	33.88	74,476.95
1994	55,014.00	40.00	1,375.31	34.58	47,557.08
1995	10,018.42	40.00	250.45	35.29	8,837.40
1996	18,736.92	40.00	468.41	36.00	16,860.99
1997	48,688.02	40.00	1,217.17	36.71	44,685.25
1998	28,319.24	40.00	707.96	37.43	26,501.34
1999	21,716.16	40.00	542.89	38.16	20,716.75
2000	19,427.04	40.00	485.66	38.89	18,888.36
2001	12,627.76	40.00	315.69	39.63	12,510.65
Total	1,367,333.66	38.96	33,955.58	23.27	790,088.49

Composite Average Remaining Life ... 23.27 Years

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1951	4,780.75	35.00	136.59	3.59	490.92
1952	11,648.96	35.00	332.83	3.82	1,271.53
1953	9,254.38	35.00	264.41	4.06	1,072.46
1954	10,489.06	35.00	299.69	4.29	1,285.64
1955	7,395.22	35.00	211.29	4.53	957.33
1956	13,405.30	35.00	383.01	4.78	1,830.74
1957	14,761.93	35.00	421.77	5.04	2,125.20
1958	8,662.47	35.00	247.50	5.31	1,314.09
1959	9,009.38	35.00	257.41	5.59	1,440.00
1960	16,520.52	35.00	472.01	5.90	2,783.21
1961	21,752.64	35.00	621.50	6.21	3,862.49
1962	22,930.52	35.00	655.16	6.55	4,293.74
1963	19,211.15	35.00	548.89	6.91	3,795.54
1964	47,764.32	35.00	1,364.69	7.30	9,961.59
1965	24,890.31	35.00	711.15	7.71	5,481.76
1966	3,434.43	35.00	98.13	8.14	798.93
1967	17,816.08	35.00	509.03	8.60	4,377.31
1968	11,507.00	35.00	328.77	9.08	2,986.26
1969	12,157.87	35.00	347.37	9.59	3,331.78
1970	27,491.19	35.00	785.46	10.12	7,952.01
1971	13,146.02	35.00	375.60	10.68	4,011.32
1972	23,833.15	35.00	680.94	11.26	7,666.05
1973	12,337.39	35.00	352.50	11.86	4,179.75
1974	25,430.15	35.00	726.57	12.48	9,064.97
1975	7,430.01	35.00	212.29	13.12	2,784.44
1976	13,137.05	35.00	375.34	13.78	5,170.42
1977	3,237.54	35.00	92.50	14.45	1,336.77

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1978	12,374.81	35.00	353.56	15.14	5,354.57
1979	3,386.23	35.00	96.75	15.85	1,533.82
1980	21,674.18	35.00	619.26	16.58	10,266.19
1981	15,086.10	35.00	431.03	17.32	7,463.89
1982	12,375.82	35.00	353.59	18.07	6,389.63
1983	14,258.52	35.00	407.38	18.84	7,674.52
1984	3,811.65	35.00	108.90	19.62	2,136.67
1986	503.67	35.00	14.39	21.22	305.38
1987	25.25	35.00	0.72	22.04	15.90
1990	1,190.88	35.00	34.03	24.57	835.83
1991	627.60	35.00	17.93	25.43	455.97
1993	261,276.45	35.00	7,465.01	27.18	202,935.12
1994	141,758.41	35.00	4,050.22	28.08	113,716.31
1995	86,702.10	35.00	2,477.19	28.98	71,779.47
1996	8,030.21	35.00	229.43	29.88	6,856.50
1997	1,198.45	35.00	34.24	30.80	1,054.64
1998	3,164.75	35.00	90.42	31.72	2,868.41
1999	445 73	35.00	12.74	32.65	415.83
2000	7,811.26	35.00	223.18	33.59	7,495.91
Total	1,009,136.86	35.00	28,832.37	18.91	545,180.78

Composite Average Remaining Life ... 18.91 Years

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1928	0.47	40.00	0.01	0.50	0.01
1929	4.51	40.00	0.11	0.57	0.06
1930	16.60	40.00	0.41	0.81	0.34
1931	40.94	40.00	1.02	1.03	1.05
1932	81.54	40.00	2.04	1.29	2.64
1933	142.15	40.00	3.55	1.55	5.49
1934	226.32	40.00	5.66	1.82	10.31
1935	338.22	40.00	8.46	2.09	17.64
1936	484.69	40.00	12.12	2.36	28.54
1937	674.62	40.00	16.87	2.60	43.79
1938	918.23	40.00	22.96	2.84	65.13
1939	1,226.43	40.00	30.66	3.06	93.68
1940	1,610.72	40.00	40.27	3.28	132.05
1946	5,354.76	40.00	133.87	4.61	617.46
1947	6,296.30	40.00	157.41	4.84	762.60
1948	7,338.16	40.00	183.45	5.09	933.50
1949	8,481.04	40.00	212.03	5.33	1,130.67
1950	31,225.77	40.00	780.64	5.59	4,363.35
1951	29,735.56	40.00	743.39	5.85	4,349.35
1952	43,159.37	40.00	1,078.98	6.13	6,610.41
1953	44,094.22	40.00	1,102.35	6.41	7,067.87
1954	21,488.00	40.00	537.20	6.71	3,606.52
1955	56,394.59	40.00	1,409.86	7.03	9,910.61
1956	105,455.40	40.00	2,636.38	7.36	19,414.98
1957	78,854.58	40.00	1,971.36	7.72	15,212.94
1958	83,821.21	40.00	2,095.52	8.09	16,952.56
1959	105,995.21	40.00	2,649.87	8.48	22,480.66

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1960	95,247.64	40.00	2,381.18	8.90	21,188.40
1961	120,016.98	40.00	3,000.41	9.34	28,010.35
1962	176,931.12	40.00	4,423.26	9.79	43,318.91
1963	167,929.33	40.00	4,198.22	10.27	43,135.28
1964	188,545.23	40.00	4,713.61	10.78	50,793.49
1965	178,449.59	40.00	4,461.22	11.30	50,412.63
1966	151,701.58	40.00	3,792.53	11.84	44,916.12
1967	177,763.45	40.00	4,444.07	12.41	55,144.30
1968	169,818.88	40.00	4,245.46	12.99	55,153.43
1969	200,222.75	40.00	5,005.55	13.59	68,047.75
1970	881,998.64	40.00	22,049.89	14.21	313,410.98
1971	315,473.45	40.00	7,886.81	14.85	117,135.34
1972	339,471.12	40.00	8,486.75	15.50	131,586.47
1973	301,802.86	40.00	7,545.05	16.18	122,043.87
1974	77,206.03	40.00	1,930.14	16.86	32,540.46
1975	211,808.52	40.00	5,295.20	17.56	92,978.35
1976	125,245.20	40.00	3,131.12	18.27	57,209.22
1977	140,141.13	40.00	3,503.52	19.00	66,561.25
1978	127,139.75	40.00	3,178.48	19.74	62,733.96
1979	59,251.12	40.00	1,481.27	20.49	30,351.08
1980	179,963.15	40.00	4,499.06	21.25	95,620.37
1981	240,432.61	40.00	6,010.80	22.03	132,419.28
1982	251,123.85	40.00	6,278.08	22.82	143,248.52
1983	175,246.69	40.00	4,381.15	23.62	103,469.06
1984	131,301.17	40.00	3,282.52	24.43	80,179.06
1985	121,371.04	40.00	3,034.27	25.25	76,606.55
1986	169,167.86	40.00	4,229.18	26.08	110,285.62

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1987	233,485.78	40.00	5,837.12	26.92	157,126.81
1988	89,442.35	40.00	2,236.05	27.77	62,091.25
1989	80,090.90	40.00	2,002.27	28.63	57,321.44
1990	57,965.14	40.00	1,449.12	29.50	42,743.63
1991	47,517.81	40.00	1,187.94	30.37	36,082.02
1992	51,810.84	40.00	1,295.27	31.26	40,487.68
1993	180,220.03	40.00	4,505.49	32.15	144,857.65
1994	479,854.46	40.00	11,996.32	33.05	396,492.58
1995	36,769.69	40.00	919.24	33.96	31,216.19
1996	51,493.49	40.00	1,287.33	34.87	44,892.08
1997	49,164.82	40.00	1,229.12	35.79	43,993.16
1998	35,738.39	40.00	893.46	36.72	32,806.03
1999	37,956.67	40.00	948.91	37.65	35,726.40
2000	120,040.57	40.00	3,001.00	38.59	115,797.11
2001	24,088.50	40.00	602.21	39.53	23,804.05
Total	7,683,869.79	40.00	192,096.10	18.78	3,607,752.41

Composite Average Remaining Life ... 18.78 Years

Montana-Dakota Utilities Company
Gas Division
380.20 SERVICES - PLASTIC
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1970	4,349.91	40.00	108.75	12.89	1,402.21
1971	8,475.72	40.00	211.89	13.56	2,873.68
1972	246,679.34	40.00	6,166.98	14.25	87,852.87
1973	222,948.72	40.00	5,573.71	14.95	83,319.56
1974	535,581.74	40.00	13,389.53	15.67	209,761.09
1975	308,709.99	40.00	7,717.74	16.40	126,579.07
1976	610,977.67	40.00	15,274.43	17.15	261,945.35
1977	420,427.67	40.00	10,510.68	17.91	188,285.97
1978	438,407.38	40.00	10,960.18	18.69	204,852.15
1979	688,347.23	40.00	17,208.67	19.48	335,269.95
1980	757,424.01	40.00	18,935.59	20.29	384,132.57
1981	635,063.55	40.00	15,876.58	21.10	335,063.58
1982	703,510.76	40.00	17,587.76	21.93	385,757.57
1983	920,900.73	40.00	23,022.50	22.78	524,357.41
1984	813,910.41	40.00	20,347.75	23.63	480,794.76
1985	912,554.35	40.00	22,813.84	24.49	558,816.49
1986	658,086.59	40.00	16,452.15	25.37	417,394.21
1987	590,828.36	40.00	14,770.70	26.26	387,842.05
1988	602,089.83	40.00	15,052.24	27.15	408,727.97
1989	488,245.35	40.00	12,206.13	28.06	342,518.08
1990	559,464.73	40.00	13,986.61	28.98	405,284.72
1991	767,360.71	40.00	19,184.00	29.90	573,634.23
1992	916,571.93	40.00	22,914.28	30.83	706,541.53
1993	1,052,736.78	40.00	26,318.40	31.77	836,265.40
1994	2,190,703.67	40.00	54,767.55	32.72	1,792,110.78
1995	1,029,959.54	40.00	25,748.97	33.68	867,134.97
1996	1,373,719.44	40.00	34,342.96	34.64	1,189,511.25

Montana-Dakota Utilities Company
Gas Division
380.20 SERVICES - PLASTIC
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1997	1,414,127.73	40.00	35,353.17	35.60	1,258,642.14
1998	1,295,966.64	40.00	32,399.14	36.57	1,184,905.00
1999	1,016,375.00	40.00	25,409.36	37.55	954,046.97
2000	1,150,408.62	40.00	28,760.20	38.53	1,108,003.00
2001	1,245,592.79	40.00	31,139.80	39.51	1,230,266.65
Total	24,580,506.89	40.00	614,512.26	29.02	17,833,893.22

Composite Average Remaining Life ... 29.02 Years

Montana-Dakota Utilities Company
Gas Division
380.30 SERVICES - FARM & FUEL LINES
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 30 *Survivor Curve: R1.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1977	681.71	30.00	22.72	12.49	283.84
1980	6,866.04	30.00	228.86	14.25	3,262.34
1981	9,184.73	30.00	306.15	14.87	4,553.62
1982	34,432.20	30.00	1,147.71	15.51	17,797.24
1983	7,969.08	30.00	265.63	16.15	4,290.83
1984	18,901.15	30.00	630.02	16.81	10,593.60
1985	13,311.43	30.00	443.70	17.49	7,759.42
1986	1,610.76	30.00	53.69	18.17	975.73
1987	1,964.42	30.00	65.48	18.87	1,235.66
1988	9,854.82	30.00	328.49	19.58	6,431.49
1989	1,711.71	30.00	57.06	20.30	1,158.09
1991	3,912.84	30.00	130.42	21.76	2,838.61
1992	4,904.22	30.00	163.47	22.51	3,679.81
1993	1,286.17	30.00	42.87	23.27	997.44
1994	63,263.97	30.00	2,108.75	24.03	50,670.23
1997	18,107.93	30.00	603.58	26.36	15,913.37
1998	3,815.98	30.00	127.20	27.16	3,454.53
1999	2,163.03	30.00	72.10	27.96	2,016.01
2000	5,016.54	30.00	167.21	28.77	4,810.99
2001	3,381.69	30.00	112.72	29.59	3,335.26
Total	212,340.42	30.00	7,077.84	20.64	146,058.12

Composite Average Remaining Life ... 20.64 Years

Montana-Dakota Utilities Company
Gas Division
381.00 METERS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1933	53,572.24	0.00	0.00	0.00	0.00
1934	54,911.54	0.00	0.00	0.00	0.00
1935	56,284.33	0.00	0.00	0.00	0.00
1936	57,691.44	0.00	0.00	0.00	0.00
1937	59,133.73	35.00	1,689.53	0.50	844.76
1938	60,612.08	35.00	1,731.77	0.55	952.80
1939	62,127.38	35.00	1,775.06	0.75	1,338.91
1940	63,680.57	35.00	1,819.44	0.97	1,758.96
1946	63,680.57	35.00	1,819.44	2.51	4,560.25
1947	63,680.57	35.00	1,819.44	2.72	4,957.44
1948	63,680.57	35.00	1,819.44	2.94	5,348.19
1949	63,680.57	35.00	1,819.44	3.15	5,739.40
1950	106,074.76	35.00	3,030.70	3.37	10,220.25
1951	358,870.10	35.00	10,253.39	3.59	36,850.92
1952	137,668.00	35.00	3,933.36	3.82	15,026.96
1953	124,738.43	35.00	3,563.94	4.06	14,455.57
1954	6,026.25	35.00	172.18	4.29	738.63
1955	236,928.39	35.00	6,769.36	4.53	30,670.91
1956	199,567.26	35.00	5,701.90	4.78	27,254.58
1957	125,461.04	35.00	3,584.59	5.04	18,061.99
1958	96,812.31	35.00	2,766.06	5.31	14,686.34
1959	167,727.91	35.00	4,792.21	5.59	26,808.57
1960	259,921.73	35.00	7,426.31	5.90	43,788.93
1961	267,404.25	35.00	7,640.09	6.21	47,481.38
1962	423,481.39	35.00	12,099.42	6.55	79,296.82
1963	323,726.26	35.00	9,249.29	6.91	63,958.47
1964	285,305.74	35.00	8,151.56	7.30	59,502.55

Montana-Dakota Utilities Company
Gas Division
381.00 METERS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1965	321,219.70	35.00	9,177.67	7.71	70,744.41
1966	299,374.74	35.00	8,553.53	8.14	69,641.66
1967	286,501.21	35.00	8,185.72	8.60	70,391.76
1968	312,230.66	35.00	8,920.84	9.08	81,028.99
1969	245,512.02	35.00	7,014.60	9.59	67,280.81
1970	566,410.51	35.00	16,183.10	10.12	163,837.95
1971	345,683.22	35.00	9,876.63	10.68	105,480.26
1972	613,062.55	35.00	17,516.01	11.26	197,194.63
1973	538,045.01	35.00	15,372.66	11.86	182,282.89
1974	1,036,260.27	35.00	29,607.32	12.48	369,390.84
1975	890,631.47	35.00	25,446.52	13.12	333,769.91
1976	829,086.51	35.00	23,688.10	13.78	326,308.20
1977	753,140.16	35.00	21,518.21	14.45	310,969.69
1978	659,058.55	35.00	18,830.17	15.14	285,173.93
1979	1,035,576.51	35.00	29,587.79	15.85	469,073.90
1980	1,011,249.85	35.00	28,892.74	16.58	478,988.47
1981	1,331,506.67	35.00	38,042.90	17.32	658,766.58
1982	463,048.24	35.00	13,229.90	18.07	239,071.68
1983	715,758.68	35.00	20,450.17	18.84	385,250.60
1984	920,252.63	35.00	26,292.83	19.62	515,860.51
1985	697,603.65	35.00	19,931.46	20.41	406,882.40
1986	359,313.39	35.00	10,266.06	21.22	217,854.94
1987	243,546.12	35.00	6,958.43	22.04	153,362.84
1988	72,200.80	35.00	2,062.87	22.87	47,177.25
1989	97,458.78	35.00	2,784.53	23.71	66,026.74
1990	341,899.44	35.00	9,768.52	24.57	239,965.21
1991	588,859.80	35.00	16,824.50	25.43	427,824.44

Montana-Dakota Utilities Company
Gas Division
381.00 METERS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R2.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	643,906.13	35.00	18,397.25	26.30	483,885.10
1993	961,288.11	35.00	27,465.27	27.18	746,638.73
1994	1,039,160.17	35.00	29,690.18	28.08	833,597.50
1995	914,202.57	35.00	26,119.97	28.98	756,855.65
1996	926,909.30	35.00	26,483.02	29.88	791,430.32
1997	1,009,110.02	35.00	28,831.60	30.80	888,018.24
1998	1,182,505.00	35.00	33,785.73	31.72	1,071,779.05
1999	1,354,437.46	35.00	38,698.06	32.65	1,263,568.17
2000	1,316,149.91	35.00	37,604.14	33.59	1,263,015.22
2001	1,697,398.85	35.00	48,496.92	34.53	1,674,496.32
Total	30,462,008.07	32.81	863,983.79	19.94	17,227,189.37

Composite Average Remaining Life ... 19.94 Years

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1946	15,339.33	35.00	438.27	0.95	417.62
1947	20,452.44	35.00	584.36	1.16	678.30
1948	20,452.44	35.00	584.36	1.39	813.79
1949	20,452.44	35.00	584.36	1.64	956.10
1950	46,006.55	35.00	1,314.47	1.89	2,479.53
1951	26,652.97	35.00	761.51	2.14	1,629.75
1952	31,906.42	35.00	911.61	2.40	2,183.87
1953	41,317.03	35.00	1,180.49	2.66	3,137.11
1954	697.55	35.00	19.93	2.91	57.99
1955	46,852.16	35.00	1,338.63	3.16	4,236.71
1956	87,838.50	35.00	2,509.67	3.42	8,594.75
1957	38,155.63	35.00	1,090.16	3.69	4,023.84
1958	30,211.34	35.00	863.18	3.97	3,424.21
1959	47,176.88	35.00	1,347.91	4.26	5,735.84
1960	75,566.77	35.00	2,159.05	4.56	9,847.52
1961	46,723.24	35.00	1,334.95	4.88	6,516.64
1962	48,755.83	35.00	1,393.02	5.22	7,276.25
1963	33,385.11	35.00	953.86	5.59	5,330.43
1964	31,932.41	35.00	912.35	5.98	5,453.92
1965	33,470.55	35.00	956.30	6.39	6,113.89
1966	18,426.68	35.00	526.48	6.84	3,598.64
1967	28,945.37	35.00	827.01	7.30	6,039.90
1968	35,304.50	35.00	1,008.70	7.80	7,867.98
1969	24,983.22	35.00	713.81	8.32	5,941.78
1970	62,666.10	35.00	1,790.46	8.87	15,889.69
1971	65,467.93	35.00	1,870.51	9.45	17,678.25
1972	100,032.41	35.00	2,858.07	10.05	28,730.07

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1973	86,348.96	35.00	2,467.11	10.68	26,342.11
1974	125,333.41	35.00	3,580.95	11.32	40,548.59
1975	126,060.93	35.00	3,601.74	11.99	43,196.63
1976	106,171.25	35.00	3,033.46	12.68	38,474.57
1977	98,333.75	35.00	2,809.53	13.39	37,627.22
1978	81,801.09	35.00	2,337.17	14.12	33,001.42
1979	104,448.86	35.00	2,984.25	14.87	44,361.35
1980	174,001.19	35.00	4,971.46	15.63	77,687.59
1981	150,939.69	35.00	4,312.56	16.40	70,739.35
1982	79,252.83	35.00	2,264.37	17.20	38,939.41
1983	104,771.15	35.00	2,993.46	18.01	53,897.27
1984	141,176.71	35.00	4,033.62	18.83	75,944.30
1985	115,881.31	35.00	3,310.89	19.66	65,107.60
1986	68,570.34	35.00	1,959.15	20.52	40,192.10
1987	51,645.71	35.00	1,475.59	21.38	31,545.98
1988	56,584.23	35.00	1,616.69	22.25	35,977.53
1989	53,259.10	35.00	1,521.69	23.14	35,215.41
1990	68,482.34	35.00	1,956.64	24.04	47,042.10
1991	96,835.74	35.00	2,766.73	24.95	69,038.75
1992	111,945.27	35.00	3,198.43	25.87	82,756.91
1993	158,823.77	35.00	4,537.82	26.80	121,635.11
1994	151,233.72	35.00	4,320.96	27.74	119,881.30
1995	108,835.62	35.00	3,109.59	28.69	89,217.64
1996	109,184.27	35.00	3,119.55	29.65	92,482.92
1997	140,318.21	35.00	4,009.09	30.61	122,710.17
1998	157,013.40	35.00	4,486.09	31.58	141,651.47
1999	123,643.41	35.00	3,532.67	32.55	114,983.53

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
2000	144,804.96	35.00	4,137.28	33.53	138,707.59
2001	121,988.61	35.00	3,485.39	34.51	120,273.41
Total	4,296,861.63	35.00	122,767.40	18.03	2,213,833.70

Composite Average Remaining Life ... 18.03 Years

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R2*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1951	3,146.19	35.00	89.89	4.04	363.18
1952	3,242.35	35.00	92.64	4.33	401.57
1953	1,441.09	35.00	41.17	4.64	190.87
1954	496.40	35.00	14.18	4.94	70.03
1955	1,573.68	35.00	44.96	5.25	235.91
1956	4,393.51	35.00	125.53	5.56	698.49
1957	3,936.77	35.00	112.48	5.89	662.71
1958	12,482.86	35.00	356.65	6.23	2,222.08
1959	4,203.13	35.00	120.09	6.58	790.33
1960	9,806.42	35.00	280.18	6.95	1,946.09
1961	7,642.28	35.00	218.35	7.32	1,599.13
1962	1,644.18	35.00	46.98	7.72	362.51
1963	10,496.72	35.00	299.90	8.13	2,436.92
1964	16,826.79	35.00	480.76	8.55	4,110.85
1965	11,613.45	35.00	331.81	8.99	2,983.73
1966	5,140.61	35.00	146.87	9.45	1,388.05
1967	3,983.88	35.00	113.82	9.93	1,129.74
1968	9,271.75	35.00	264.91	10.42	2,759.75
1969	12,629.51	35.00	360.84	10.93	3,943.11
1970	10,563.42	35.00	301.81	11.45	3,456.99
1971	4,636.91	35.00	132.48	12.00	1,589.47
1972	3,883.36	35.00	110.95	12.56	1,393.30
1973	5,911.21	35.00	168.89	13.13	2,218.21
1974	2,838.43	35.00	81.10	13.73	1,113.09
1975	7,718.99	35.00	220.54	14.33	3,161.22
1980	8,838.28	35.00	252.52	17.60	4,444.38
1981	224.44	35.00	6.41	18.29	117.31

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R2*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1982	1,679.89	35.00	48.00	19.00	912.09
1983	1,393.22	35.00	39.81	19.72	785.17
1984	28,182.42	35.00	805.21	20.46	16,473.79
1985	70,796.01	35.00	2,022.73	21.21	42,892.61
1986	4,535.58	35.00	129.59	21.96	2,846.16
1987	50,486.15	35.00	1,442.45	22.73	32,790.97
1988	74,749.20	35.00	2,135.68	23.51	50,215.34
1989	126.98	35.00	3.63	24.30	88.18
1990	20,003.44	35.00	571.52	25.11	14,349.13
1991	16,497.62	35.00	471.36	25.92	12,217.33
1992	14,151.76	35.00	404.33	26.74	10,812.70
1993	23,634.12	35.00	675.26	27.57	18,619.74
1994	11,333.23	35.00	323.80	28.42	9,201.24
1995	1,963.26	35.00	56.09	29.27	1,641.62
1996	20,597.62	35.00	588.50	30.13	17,729.21
1997	39,063.08	35.00	1,116.08	30.99	34,592.44
1998	7,113.21	35.00	203.23	31.87	6,477.30
1999	13,371.89	35.00	382.05	32.76	12,514.44
2000	8,644.92	35.00	247.00	33.65	8,310.97
2001	1,289.78	35.00	36.85	34.55	1,273.11
Total	578,199.99	35.00	16,519.89	20.61	340,532.61

Composite Average Remaining Life ... 20.61 Years

Montana-Dakota Utilities Company

Gas Division

386.10 MISC. PROPERTY ON CUSTOMERS PREMISE

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 15 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1997	1,679.84	15.00	111.99	10.69	1,197.69
Total	1,679.84	15.00	111.99	10.69	1,197.69

Composite Average Remaining Life ... 10.69 Years

Montana-Dakota Utilities Company
Gas Division
386.20 CNG REFUELING STATIONS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 15 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	94,415.93	15.00	6,294.36	6.48	40,795.80
1993	23,150.61	15.00	1,543.36	7.26	11,201.45
1994	152,653.42	15.00	10,176.83	8.07	82,132.19
1995	134,379.57	15.00	8,958.58	8.92	79,874.42
1996	28,211.95	15.00	1,880.78	9.79	18,415.54
Total	432,811.48	15.00	28,853.92	8.06	232,419.40

Composite Average Remaining Life ... 8.06 Years

Montana-Dakota Utilities Company
Gas Division
387.10 CATHODIC PROTECTION EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20 *Survivor Curve: R1.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1948	3,460.08	0.00	0.00	0.00	0.00
1949	5,169.71	0.00	0.00	0.00	0.00
1950	1,079.56	0.00	0.00	0.00	0.00
1951	6,978.28	0.00	0.00	0.00	0.00
1952	812.02	0.00	0.00	0.00	0.00
1953	53.18	0.00	0.00	0.00	0.00
1954	135.09	0.00	0.00	0.00	0.00
1955	1,567.36	0.00	0.00	0.00	0.00
1956	1,011.36	0.00	0.00	0.00	0.00
1957	5,932.62	0.00	0.00	0.00	0.00
1958	4,598.55	0.00	0.00	0.00	0.00
1959	9,699.90	0.00	0.00	0.00	0.00
1960	18,751.57	0.00	0.00	0.00	0.00
1961	18,792.31	0.00	0.00	0.00	0.00
1962	12,387.31	20.00	619.34	0.50	309.67
1963	18,536.50	20.00	926.78	0.67	617.25
1964	11,522.62	20.00	576.11	0.96	550.88
1965	9,774.67	20.00	488.71	1.27	619.57
1966	3,146.35	20.00	157.31	1.52	238.42
1967	8,884.16	20.00	444.19	1.74	774.28
1968	12,226.17	20.00	611.28	1.96	1,198.91
1969	28,720.02	20.00	1,435.94	2.20	3,161.30
1970	10,233.27	20.00	511.64	2.45	1,254.29
1971	15,361.22	20.00	768.03	2.72	2,089.85
1972	20,723.77	20.00	1,036.14	3.00	3,106.56
1973	18,996.13	20.00	949.76	3.29	3,124.67
1974	19,782.49	20.00	989.08	3.59	3,550.70

Montana-Dakota Utilities Company
Gas Division
387.10 CATHODIC PROTECTION EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20 *Survivor Curve: R1.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1975	9,071.83	20.00	453.57	3.91	1,771.39
1976	20,699.75	20.00	1,034.94	4.23	4,382.61
1977	29,911.03	20.00	1,495.49	4.58	6,854.61
1978	32,801.41	20.00	1,640.00	4.95	8,122.08
1979	15,857.03	20.00	792.82	5.34	4,237.46
1980	30,224.76	20.00	1,511.17	5.76	8,707.10
1981	27,402.80	20.00	1,370.08	6.20	8,500.55
1982	34,331.65	20.00	1,716.51	6.67	11,454.65
1983	50,053.19	20.00	2,502.55	7.17	17,937.97
1984	60,226.67	20.00	3,011.20	7.69	23,155.21
1985	72,842.19	20.00	3,641.95	8.24	29,994.78
1986	100,389.75	20.00	5,019.27	8.81	44,210.64
1987	42,191.64	20.00	2,109.49	9.40	19,835.70
1988	80,140.85	20.00	4,006.87	10.02	40,157.05
1989	22,764.82	20.00	1,138.19	10.66	12,134.75
1990	14,640.01	20.00	731.97	11.32	8,287.66
1991	75,451.31	20.00	3,772.40	12.00	45,273.80
1992	34,591.08	20.00	1,729.48	12.70	21,962.72
1993	42,721.43	20.00	2,135.98	13.41	28,647.84
1994	69,871.16	20.00	3,493.40	14.14	49,400.17
1995	16,598.80	20.00	829.90	14.88	12,351.18
1996	47,748 91	20.00	2,387.34	15.64	37,331.94
1997	54,466.52	20.00	2,723.21	16.40	44,672.27
1998	47,847.36	20.00	2,392.26	17.18	41,107.18
1999	41,807.52	20.00	2,090.28	17.97	37,569.73
2000	52,281.75	20.00	2,613.97	18.78	49,080.07
2001	55,385.74	20.00	2,769.17	19.59	54,246.35

Montana-Dakota Utilities Company

Gas Division

387.10 CATHODIC PROTECTION EQUIP.

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20 *Survivor Curve: R1.5*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
Total	1,450,657.23	14.82	68,627.78	10.08	691,983.84

Composite Average Remaining Life ... 10.08 Years

Montana-Dakota Utilities Company
Gas Division
387.20 OTHER DISTRIBUTION EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 25 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1950	5,304.95	0.00	0.00	0.00	0.00
1951	17,776.59	0.00	0.00	0.00	0.00
1952	7,600.80	0.00	0.00	0.00	0.00
1953	470.19	0.00	0.00	0.00	0.00
1955	9,921.56	0.00	0.00	0.00	0.00
1956	1,631.55	0.00	0.00	0.00	0.00
1958	6,778.42	0.00	0.00	0.00	0.00
1959	7,357.37	0.00	0.00	0.00	0.00
1960	13,723.17	25.00	548.93	0.50	274.46
1961	1,693.29	25.00	67.73	0.57	38.39
1962	3,222.74	25.00	128.91	0.75	96.34
1963	12,996.97	25.00	519.88	0.96	501.11
1964	2,787.40	25.00	111.50	1.20	133.66
1965	3,053.39	25.00	122.14	1.44	176.37
1966	688.77	25.00	27.55	1.69	46.69
1967	2,662.44	25.00	106.50	1.95	207.38
1968	921.58	25.00	36.86	2.20	81.15
1969	399.20	25.00	15.97	2.46	39.28
1970	3,211.00	25.00	128.44	2.73	350.20
1971	159.96	25.00	6.40	3.01	19.25
1974	250.65	25.00	10.03	4.00	40.09
1978	374.73	25.00	14.99	5.80	86.90
1987	12,574.88	25.00	502.99	11.83	5,950.60
1988	22,536.58	25.00	901.46	12.63	11,384.89
1989	17,890.76	25.00	715.63	13.45	9,624.49
1990	26,772.06	25.00	1,070.88	14.29	15,301.10
1991	5,904.13	25.00	236.16	15.15	3,577.07

Montana-Dakota Utilities Company
Gas Division
387.20 OTHER DISTRIBUTION EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 25 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	16,187.96	25.00	647.52	16.02	10,374.88
1993	16,288.09	25.00	651.52	16.92	11,020.76
1994	64,000.04	25.00	2,560.00	17.82	45,629.09
1995	11,278.48	25.00	451.14	18.75	8,457.37
1996	56,219.62	25.00	2,248.78	19.68	44,261.82
1997	35,224.20	25.00	1,408.96	20.63	29,067.02
1998	9,564.17	25.00	382.57	21.59	8,258.72
2000	159,755.80	25.00	6,390.22	23.53	150,348.99
Total	557,183.49	19.29	20,013.64	17.76	355,348.07

Composite Average Remaining Life ... 17.76 Years

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1928	5,724.99	0.00	0.00	0.00	0.00
1929	5,868.12	0.00	0.00	0.00	0.00
1930	6,014.83	0.00	0.00	0.00	0.00
1931	6,165.20	0.00	0.00	0.00	0.00
1932	6,319 33	0.00	0.00	0.00	0.00
1933	6,477.31	0.00	0.00	0.00	0.00
1934	6,639.24	0.00	0.00	0.00	0.00
1935	6,805.22	0.00	0.00	0.00	0.00
1936	6,975.35	0.00	0.00	0.00	0.00
1937	7,149.74	0.00	0.00	0.00	0.00
1938	7,328 48	0.00	0.00	0.00	0.00
1939	7,511.69	0.00	0.00	0.00	0.00
1940	7,699 49	0.00	0.00	0.00	0.00
1946	7,699.49	35.00	219.99	0.95	209.62
1947	7,699.49	35.00	219.99	1.16	255.35
1948	7,699.49	35.00	219.99	1.39	306.36
1949	48,009.12	35.00	1,371.69	1.64	2,244.31
1950	20,461.35	35.00	584.61	1.89	1,102.77
1951	192,679.47	35.00	5,505.12	2.14	11,781.75
1952	11,448.42	35.00	327.10	2.40	783.60
1953	24,688.97	35.00	705.40	2.66	1,874.58
1954	4,289.61	35.00	122.56	2.91	356.61
1955	83,360 24	35.00	2,381.72	3.16	7,538.04
1956	144,412.30	35.00	4,126.06	3.42	14,130.34
1957	5,597.53	35.00	159.93	3.69	590.31
1958	2,427.85	35.00	69.37	3.97	275.18
1959	2,710.53	35.00	77.44	4.26	329.55

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1960	25,605.64	35.00	731.59	4.56	3,336.81
1961	11,185.92	35.00	319.60	4.88	1,560.14
1962	6,880.29	35.00	196.58	5.22	1,026.80
1963	10,358.66	35.00	295.96	5.59	1,653.91
1964	22,703.00	35.00	648.66	5.98	3,877.58
1965	66,049.79	35.00	1,887.14	6.39	12,064.96
1966	73,815.40	35.00	2,109.01	6.84	14,415.77
1967	13,242.19	35.00	378.35	7.30	2,763.19
1968	4,621.05	35.00	132.03	7.80	1,029.85
1969	5,738.48	35.00	163.96	8.32	1,364.79
1970	179,765.26	35.00	5,136.15	8.87	45,581.50
1971	10,827.96	35.00	309.37	9.45	2,923.87
1972	148,803.54	35.00	4,251.53	10.05	42,737.51
1973	45,404.27	35.00	1,297.26	10.68	13,851.29
1974	9,288.80	35.00	265.39	11.32	3,005.17
1975	9,264.96	35.00	264.71	11.99	3,174.77
1976	26,236.68	35.00	749.62	12.68	9,507.71
1977	6,472.33	35.00	184.92	13.39	2,476.62
1978	81,258.43	35.00	2,321.67	14.12	32,782.49
1979	2,840.64	35.00	81.16	14.87	1,206.47
1980	39,085.66	35.00	1,116.73	15.63	17,450.86
1981	15,113.41	35.00	431.81	16.40	7,083.05
1982	13,896.18	35.00	397.03	17.20	6,827.63
1983	43,570.61	35.00	1,244.87	18.01	22,413.97
1984	44,396.73	35.00	1,268.48	18.83	23,882.68
1985	22,557.63	35.00	644.50	19.66	12,673.94
1986	48,046.38	35.00	1,372.75	20.52	28,162.10

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1987	6,942.55	35.00	198.36	21.38	4,240.62
1988	13,916.95	35.00	397.63	22.25	8,848.71
1989	15,829.80	35.00	452.28	23.14	10,466.81
1990	4,622.41	35.00	132.07	24.04	3,175.24
1991	18,934.94	35.00	541.00	24.95	13,499.61
1992	2,004.71	35.00	57.28	25.87	1,482.01
1993	62,916 45	35.00	1,797.61	26.80	48,184.53
1994	34,540.14	35.00	986.86	27.74	27,379.59
1996	6,751.79	35.00	192.91	29.65	5,719.00
1997	39,583.08	35.00	1,130.94	30.61	34,615.94
1998	20,939.10	35.00	598.26	31.58	18,890.45
1999	23,907.59	35.00	683.07	32.55	22,233.12
2000	25,989.76	35.00	742.56	33.53	24,895.40
2001	9,211.06	35.00	263.17	34.51	9,081.55
Total	1,922,983.07	28.31	52,465.80	11.31	593,326.37

Composite Average Remaining Life ... 11.31 Years

Montana-Dakota Utilities Company
Gas Division
391.30 . COMPUTER EQUIPMENT - PC
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 5 *Survivor Curve:* R2

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1991	69,518.10	0.00	0.00	0.00	0.00
1992	2,517.50	0.00	0.00	0.00	0.00
1993	28,091.76	5.00	5,616.05	0.50	2,808.02
1994	85,179.24	5.00	17,028.86	0.61	10,426.32
1995	78,464.33	5.00	15,686.43	0.87	13,573.38
1996	63,562.14	5.00	12,707.21	1.20	15,276.77
1997	61,036.44	5.00	12,202.28	1.66	20,251.51
1998	45,805.38	5.00	9,157.32	2.24	20,522.79
1999	29,475.86	5.00	5,892.75	2.93	17,265.92
2000	299,952.51	5.00	59,965.88	3.71	222,284.12
2001	17,391.28	5.00	3,476.83	4.56	15,837.72
Total	780,994.54	4.09	141,733.60	2.39	338,246.54

Composite Average Remaining Life ... 2.39 Years

Montana-Dakota Utilities Company

Gas Division

392.10 TRANSPORTATION EQUIPMENT - TRAILERS

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 8 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	3,969.57	8.00	496.18	1.09	541.26
1993	8,455.12	8.00	1,056.86	1.43	1,510.26
1994	6,650.63	8.00	831.30	1.88	1,566.64
1995	4,652.37	8.00	581.53	2.46	1,431.33
1996	159.25	8.00	19.91	3.14	62.51
1997	13,224.10	8.00	1,652.96	3.90	6,447.69
1998	6,114.58	8.00	764.30	4.73	3,613.74
2000	91,248.96	8.00	11,405.75	6.55	74,651.23
2001	12,712.08	8.00	1,588.96	7.51	11,932.59
Total	147,186.66	8.00	18,397.74	5.53	101,757.23

Composite Average Remaining Life ... 5.53 Years

Montana-Dakota Utilities Company

Gas Division

392.20 TRANSPORTATION EQUIPMENT - CARS & TRUCKS

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 6 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1995	3,205,665.88	6.00	534,252.96	1.05	558,849.61
1996	279,631.19	6.00	46,603.04	1.49	69,460.76
1997	434,491.24	6.00	72,411.86	2.10	151,880.51
1998	483,991.51	6.00	80,661.52	2.83	228,223.93
1999	385,248.75	6.00	64,205.16	3.66	234,680.29
2000	711,300.38	6.00	118,544.58	4.56	540,108.75
2001	580,232.10	6.00	96,700.88	5.51	532,869.62
Total	6,080,561.05	6.00	1,013,380.01	2.29	2,316,073.47

Composite Average Remaining Life ... 2.29 Years

Montana-Dakota Utilities Company
Gas Division
396.10 WORK EQUIPMENT TRAILERS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 10 *Survivor Curve: R2*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	15,220.49	10.00	1,521.91	3.03	4,604.16
1993	29,080.60	10.00	2,907.80	3.56	10,342.67
1994	36,357.64	10.00	3,635.43	4.15	15,075.30
1995	28,317.13	10.00	2,831.46	4.79	13,565.38
1996	61,784.24	10.00	6,177.86	5.48	33,884.32
1997	10,424.26	10.00	1,042.33	6.22	6,487.16
1998	18,323.26	10.00	1,832.16	7.00	12,831.47
1999	68,853.28	10.00	6,884.70	7.82	53,840.31
2000	4,825.27	10.00	482.48	8.67	4,183.39
2001	20,357.28	10.00	2,035.54	9.55	19,440.81
Total	293,543.45	10.00	29,351.68	5.94	174,254.97

Composite Average Remaining Life ... 5.94 Years

Montana-Dakota Utilities Company
Gas Division
396.20 POWER OPERATED EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 7 *Survivor Curve:* R2

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1963	189,525.77	0.00	0.00	0.00	0.00
1964	21,481.21	0.00	0.00	0.00	0.00
1965	28,648.73	0.00	0.00	0.00	0.00
1966	7,947.13	0.00	0.00	0.00	0.00
1967	29,582.69	0.00	0.00	0.00	0.00
1968	11,484.93	0.00	0.00	0.00	0.00
1969	9,509.90	0.00	0.00	0.00	0.00
1970	33,579.03	0.00	0.00	0.00	0.00
1971	21,425.78	0.00	0.00	0.00	0.00
1972	30,799.45	0.00	0.00	0.00	0.00
1973	35,683.77	0.00	0.00	0.00	0.00
1974	48,747.59	0.00	0.00	0.00	0.00
1975	21,745.23	0.00	0.00	0.00	0.00
1976	43,444.66	0.00	0.00	0.00	0.00
1977	2,523.35	0.00	0.00	0.00	0.00
1978	10,027.19	0.00	0.00	0.00	0.00
1979	37,454.57	0.00	0.00	0.00	0.00
1980	39,398.51	0.00	0.00	0.00	0.00
1981	98,796.65	0.00	0.00	0.00	0.00
1982	54,649.86	0.00	0.00	0.00	0.00
1983	217,626.59	0.00	0.00	0.00	0.00
1984	46,062.62	0.00	0.00	0.00	0.00
1985	34,651.47	0.00	0.00	0.00	0.00
1986	33,827.02	0.00	0.00	0.00	0.00
1987	35,932.56	0.00	0.00	0.00	0.00
1988	83,164.27	0.00	0.00	0.00	0.00
1989	167,836.12	7.00	23,972.18	0.50	11,986.09

Montana-Dakota Utilities Company
Gas Division
396.20 POWER OPERATED EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 7 *Survivor Curve:* R2

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1990	121,448.25	7.00	17,346.56	0.54	9,442.67
1991	122,504.49	7.00	17,497.42	0.77	13,532.27
1992	127,333.28	7.00	18,187.12	1.04	18,980.69
1993	206,179.40	7.00	29,448.78	1.36	39,910.20
1994	210,673.52	7.00	30,090.68	1.74	52,255.10
1995	278,225.11	7.00	39,739.14	2.20	87,547.88
1996	156,322.95	7.00	22,327.74	2.76	61,549.92
1997	405,071.42	7.00	57,856.71	3.39	196,209.66
1998	190,665.94	7.00	27,232.98	4.10	111,569.19
1999	383,987.26	7.00	54,845.24	4.86	266,777.35
2000	117,903.40	7.00	16,840.25	5.69	95,742.36
2001	365,896.66	7.00	52,261.34	6.55	342,442.15
Total	4,081,768.33	2.33	407,646.16	3.21	1,307,945.54

Composite Average Remaining Life ... 3.21 Years

Montana-Dakota Utilities Company
Gas Division
376.10 MAINS - STEEL
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -60 % Average Service Life: 45 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1926	0.46	0.50	45.00	1.58222	1
1927	7.90	0.54	45.00	1.58083	12
1928	37.89	0.68	45.00	1.57594	60
1929	111.24	0.91	45.00	1.56762	174
1930	253.98	1.14	45.00	1.55953	396
1931	493.63	1.37	45.00	1.55129	766
1932	856.11	1.59	45.00	1.54350	1,321
1933	1,369.83	1.84	45.00	1.53464	2,102
1934	2,064.35	2.09	45.00	1.52567	3,150
1935	2,979.79	2.34	45.00	1.51662	4,519
1936	4,142.79	2.60	45.00	1.50751	6,245
1937	5,589.93	2.84	45.00	1.49886	8,379
1938	7,360.90	3.10	45.00	1.48966	10,965
1939	9,505.32	3.36	45.00	1.48045	14,072
1940	12,069.90	3.62	45.00	1.47125	17,758
1946	33,260.85	5.21	45.00	1.41461	47,051
1947	37,960.11	5.51	45.00	1.40420	53,304
1948	42,934.21	5.81	45.00	1.39337	59,823
1949	49,410.04	6.13	45.00	1.38205	68,287
1950	226,630.30	6.46	45.00	1.37025	310,541
1951	481,470.34	6.81	45.00	1.35780	653,738
1952	306,423.81	7.18	45.00	1.34470	412,049
1953	276,769.47	7.57	45.00	1.33094	368,364
1954	87,775.92	7.97	45.00	1.31648	115,556
1955	747,194.20	8.40	45.00	1.30126	972,295
1956	550,540.11	8.85	45.00	1.28533	707,625
1957	325,394.39	9.32	45.00	1.26865	412,812
1958	431,107.00	9.81	45.00	1.25123	539,414

Montana-Dakota Utilities Company
Gas Division
376.10 MAINS - STEEL
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -60 % Average Service Life: 45 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1959	553,122.71	10.32	45.00	1.23298	681,987
1960	732,597.62	10.86	45.00	1.21404	889,403
1961	636,569.71	11.41	45.00	1.19438	760,307
1962	936,723.36	11.98	45.00	1.17401	1,099,725
1963	884,989.06	12.57	45.00	1.15296	1,020,353
1964	839,286.79	13.19	45.00	1.13111	949,328
1965	870,931.68	13.82	45.00	1.10871	965,615
1966	610,660.47	14.46	45.00	1.08570	662,993
1967	857,538.32	15.13	45.00	1.06209	910,782
1968	1,051,320.08	15.81	45.00	1.03782	1,091,082
1969	962,546.26	16.51	45.00	1.01307	975,126
1970	3,244,082.74	17.22	45.00	0.98780	3,204,495
1971	797,467.90	17.94	45.00	0.96202	767,183
1972	831,037.98	18.68	45.00	0.93577	777,657
1973	911,086.63	19.44	45.00	0.90895	828,133
1974	450,583.23	20.20	45.00	0.88175	397,302
1975	69,798.16	20.98	45.00	0.85412	59,616
1976	733,622.14	21.77	45.00	0.82605	606,012
1977	402,611.06	22.57	45.00	0.79751	321,087
1978	399,496.10	23.38	45.00	0.76861	307,057
1979	696,362.97	24.21	45.00	0.73931	514,831
1980	850,615.59	25.04	45.00	0.70963	603,625
1981	1,026,692.11	25.89	45.00	0.67958	697,715
1982	1,222,659.70	26.74	45.00	0.64909	793,611
1983	978,065.89	27.61	45.00	0.61829	604,727
1984	321,413.35	28.49	45.00	0.58715	188,717
1985	838,322.58	29.37	45.00	0.55567	465,831
1986	1,271,814.28	30.27	45.00	0.52383	666,211

Montana-Dakota Utilities Company
Gas Division
376.10 MAINS - STEEL

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -60 % *Average Service Life:* 45 *Survivor Curve:* R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1987	366,675.95	31.17	45.00	0.49171	180,297
1988	571,181.31	32.08	45.00	0.45929	262,338
1989	488,132.96	33.00	45.00	0.42659	208,234
1990	455,212.65	33.93	45.00	0.39363	179,185
1991	545,918.18	34.86	45.00	0.36037	196,734
1992	634,284.39	35.81	45.00	0.32691	207,353
1993	1,167,286.50	36.75	45.00	0.29322	342,277
1994	385,982.98	37.71	45.00	0.25933	100,099
1995	93,676.43	38.67	45.00	0.22523	21,099
1996	184,525.08	39.63	45.00	0.19097	35,238
1997	112,135.50	40.60	45.00	0.15654	17,554
1998	267,853.04	41.57	45.00	0.12197	32,671
1999	419,826.94	42.55	45.00	0.08727	36,639
2000	417,773.20	43.53	45.00	0.05243	21,905
2001	112,871.05	44.51	45.00	0.01750	1,975
Total	33,849,069.40				28,444,887.67

Montana-Dakota Utilities Company
Gas Division
376.20 MAINS - PLASTIC
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -60 % Average Service Life: 45 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1970	376,595.78	17.22	45.00	0.98780	372,000
1971	144,804.26	17.94	45.00	0.96202	139,305
1972	1,297,016.85	18.68	45.00	0.93577	1,213,704
1973	299,374.48	19.44	45.00	0.90895	272,117
1974	241,086.49	20.20	45.00	0.88175	212,578
1975	894,989.19	20.98	45.00	0.85412	764,425
1976	659,925.68	21.77	45.00	0.82605	545,135
1977	324,341.06	22.57	45.00	0.79751	258,666
1978	525,534.89	23.38	45.00	0.76861	403,931
1979	1,118,014.33	24.21	45.00	0.73931	826,564
1980	1,530,214.91	25.04	45.00	0.70963	1,085,891
1981	1,159,108.23	25.89	45.00	0.67958	787,702
1982	1,163,169.54	26.74	45.00	0.64909	754,997
1983	1,182,122.34	27.61	45.00	0.61829	730,892
1984	1,267,929.23	28.49	45.00	0.58715	744,460
1985	1,280,656.53	29.37	45.00	0.55567	711,623
1986	1,208,207.48	30.27	45.00	0.52383	632,892
1987	1,272,224.15	31.17	45.00	0.49171	625,560
1988	799,348.47	32.08	45.00	0.45929	367,133
1989	625,863.79	33.00	45.00	0.42659	266,989
1990	918,177.66	33.93	45.00	0.39363	361,421
1991	1,282,397.31	34.86	45.00	0.36037	462,140
1992	1,920,024.13	35.81	45.00	0.32691	627,673
1993	6,817,223.98	36.75	45.00	0.29322	1,998,978
1994	4,272,376.85	37.71	45.00	0.25933	1,107,974
1995	1,272,617.52	38.67	45.00	0.22523	286,631
1996	2,332,294.70	39.63	45.00	0.19097	445,389
1997	1,996,631.35	40.60	45.00	0.15654	312,558

Montana-Dakota Utilities Company
Gas Division
376.20 MAINS - PLASTIC
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -60 % *Average Service Life:* 45 *Survivor Curve:* R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1998	1,493,127.53	41.57	45.00	0.12197	182,121
1999	1,087,269.93	42.55	45.00	0.08727	94,887
2000	1,506,913.52	43.53	45.00	0.05243	79,012
2001	1,743,393.04	44.51	45.00	0.01750	30,512
Total	44,012,975.20				17,705,859.92

Montana-Dakota Utilities Company
Gas Division
376.30 MAINS - VALVES
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -60 % Average Service Life: 40 Survivor Curve: R2.5

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1977	1,442.20	19.00	40.00	0.84007	1,212
1978	3,373.98	19.74	40.00	0.81052	2,735
1979	8,309.96	20.49	40.00	0.78041	6,485
1980	3,512.48	21.25	40.00	0.74987	2,634
1981	2,710.94	22.03	40.00	0.71879	1,949
1982	10,041.69	22.82	40.00	0.68731	6,902
1983	1,791.09	23.62	40.00	0.65533	1,174
1984	8,052.13	24.43	40.00	0.62296	5,016
1985	38,658.45	25.25	40.00	0.59012	22,813
1986	10,734.69	26.08	40.00	0.55691	5,978
1987	28,426.45	26.92	40.00	0.52326	14,874
1988	24,014.92	27.77	40.00	0.48927	11,750
1989	8,493.27	28.63	40.00	0.45487	3,863
1990	5,192.49	29.50	40.00	0.42016	2,182
1991	3,640.35	30.37	40.00	0.38506	1,402
1992	13,194.19	31.26	40.00	0.34968	4,614
1993	142,145.32	32.15	40.00	0.31395	44,626
1994	17,817.20	33.05	40.00	0.27796	4,952
1995	4,300.00	33.96	40.00	0.24166	1,039
1997	5,405.53	35.79	40.00	0.16830	910
1999	36,828.93	37.65	40.00	0.09401	3,462
2000	8,767.06	38.59	40.00	0.05656	496
2001	4,650.56	39.53	40.00	0.01889	88
Total	391,503.88				151,155.46

Montana-Dakota Utilities Company

Gas Division

376.40 MAINS - MANHOLES

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -60 % Average Service Life: 45 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1960	9.90	10.86	45.00	1.21404	12
1978	3,706.52	23.38	45.00	0.76861	2,849
1979	1,211.43	24.21	45.00	0.73931	896
1980	7,430.06	25.04	45.00	0.70963	5,273
1981	4,708.73	25.89	45.00	0.67958	3,200
1982	10,590.76	26.74	45.00	0.64909	6,874
1983	4,593.08	27.61	45.00	0.61829	2,840
1984	2,952.00	28.49	45.00	0.58715	1,733
1985	5,397.11	29.37	45.00	0.55567	2,999
1986	1,716.97	30.27	45.00	0.52383	899
1987	3,512.13	31.17	45.00	0.49171	1,727
1988	3,739.38	32.08	45.00	0.45929	1,717
1990	9,279.86	33.93	45.00	0.39363	3,653
1991	1,140.52	34.86	45.00	0.36037	411
1993	4,344.30	36.75	45.00	0.29322	1,274
1995	2,299.05	38.67	45.00	0.22523	518
1996	3,287.49	39.63	45.00	0.19097	628
Total	69,919.29				37,502.59

Montana-Dakota Utilities Company
Gas Division
376.50 MAINS - BRIDGE & RIVER CROSSINGS
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -60 % Average Service Life: 45 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1995	8,923.21	38.67	45.00	0.22523	2,010
1996	39.60	39.63	45.00	0.19097	8
1998	1,723.00	41.57	45.00	0.12197	210
Total	10,685.81				2,227.49

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -175 % Average Service Life: 40 Survivor Curve: R2.5

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1928	0.47	0.50	40.00	2.71563	1
1929	4.51	0.57	40.00	2.71047	12
1930	16.60	0.81	40.00	2.69448	45
1931	40.94	1.03	40.00	2.67926	110
1932	81.54	1.29	40.00	2.66106	217
1933	142.15	1.55	40.00	2.64374	376
1934	226.32	1.82	40.00	2.62473	594
1935	338.22	2.09	40.00	2.60656	882
1936	484.69	2.36	40.00	2.58807	1,254
1937	674.62	2.60	40.00	2.57148	1,735
1938	918.23	2.84	40.00	2.55495	2,346
1939	1,226.43	3.06	40.00	2.53995	3,115
1940	1,610.72	3.28	40.00	2.52454	4,066
1946	5,354.76	4.61	40.00	2.43289	13,028
1947	6,296.30	4.84	40.00	2.41692	15,218
1948	7,338.16	5.09	40.00	2.40017	17,613
1949	8,481.04	5.33	40.00	2.38338	20,214
1950	31,225 77	5.59	40.00	2.36573	73,872
1951	29,735.56	5.85	40.00	2.34776	69,812
1952	43,159.37	6.13	40.00	2.32880	100,510
1953	44,094.22	6.41	40.00	2.30920	101,822
1954	21,488.00	6.71	40.00	2.28844	49,174
1955	56,394.59	7.03	40.00	2.26672	127,831
1956	105,455.40	7.36	40.00	2.24371	236,611
1957	78,854.58	7.72	40.00	2.21946	175,015
1958	83,821.21	8.09	40.00	2.19382	183,889
1959	105,995.21	8.48	40.00	2.16675	229,665
1960	95,247.64	8.90	40.00	2.13825	203,663

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -175 % Average Service Life: 40 Survivor Curve: R2.5

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1961	120,016.98	9.34	40.00	2.10819	253,018
1962	176,931.12	9.79	40.00	2.07670	367,434
1963	167,929.33	10.27	40.00	2.04362	343,184
1964	188,545.23	10.78	40.00	2.00916	378,817
1965	178,449.59	11.30	40.00	1.97312	352,102
1966	151,701.58	11.84	40.00	1.93577	293,660
1967	177,763.45	12.41	40.00	1.89692	337,203
1968	169,818.88	12.99	40.00	1.85686	315,330
1969	200,222.75	13.59	40.00	1.81538	363,481
1970	881,998.64	14.21	40.00	1.77281	1,563,616
1971	315,473.45	14.85	40.00	1.72892	545,430
1972	339,471.12	15.50	40.00	1.68404	571,683
1973	301,802.86	16.18	40.00	1.63795	494,337
1974	77,206.03	16.86	40.00	1.59094	122,830
1975	211,808.52	17.56	40.00	1.54282	326,783
1976	125,245.20	18.27	40.00	1.49386	187,099
1977	140,141.13	19.00	40.00	1.44386	202,345
1978	127,139.75	19.74	40.00	1.39308	177,116
1979	59,251.12	20.49	40.00	1.34133	79,475
1980	179,963.15	21.25	40.00	1.28883	231,943
1981	240,432.61	22.03	40.00	1.23543	297,037
1982	251,123.85	22.82	40.00	1.18132	296,657
1983	175,246.69	23.62	40.00	1.12635	197,388
1984	131,301.17	24.43	40.00	1.07071	140,586
1985	121,371.04	25.25	40.00	1.01426	123,102
1986	169,167.86	26.08	40.00	0.95719	161,926
1987	233,485.78	26.92	40.00	0.89936	209,987
1988	89,442.35	27.77	40.00	0.84094	75,216

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -175 % Average Service Life: 40 Survivor Curve: R2.5

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1989	80,090.90	28.63	40.00	0.78181	62,616
1990	57,965 14	29.50	40.00	0.72214	41,859
1991	47,517.81	30.37	40.00	0.66182	31,448
1992	51,810.84	31.26	40.00	0.60101	31,139
1993	180,220.03	32.15	40.00	0.53960	97,247
1994	479,854.46	33.05	40.00	0.47774	229,245
1995	36,769.69	33.96	40.00	0.41535	15,272
1996	51,493 49	34.87	40.00	0.35255	18,154
1997	49,164.82	35.79	40.00	0.28927	14,222
1998	35,738.39	36.72	40.00	0.22564	8,064
1999	37,956.67	37.65	40.00	0.16159	6,133
2000	120,040.57	38.59	40.00	0.09721	11,670
2001	24,088.50	39.53	40.00	0.03247	782
Total	7,683,869.79				11,209,322.80

Montana-Dakota Utilities Company
Gas Division
380.20 SERVICES - PLASTIC
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -175 % Average Service Life: 40 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1970	4,349.91	12.89	40.00	1.86353	8,106
1971	8,475.72	13.56	40.00	1.81762	15,406
1972	246,679.34	14.25	40.00	1.77061	436,773
1973	222,948.72	14.95	40.00	1.72228	383,980
1974	535,581.74	15.67	40.00	1.67296	896,007
1975	308,709.99	16.40	40.00	1.62243	500,860
1976	610,977.67	17.15	40.00	1.57099	959,839
1977	420,427.67	17.91	40.00	1.51843	638,390
1978	438,407.38	18.69	40.00	1.46502	642,277
1979	688,347.23	19.48	40.00	1.41057	970,963
1980	757,424.01	20.29	40.00	1.35532	1,026,551
1981	635,063.55	21.10	40.00	1.29908	825,000
1982	703,510.76	21.93	40.00	1.24209	873,821
1983	920,900.73	22.78	40.00	1.18416	1,090,494
1984	813,910.41	23.63	40.00	1.12551	916,068
1985	912,554.35	24.49	40.00	1.06600	972,779
1986	658,086.59	25.37	40.00	1.00580	661,904
1987	590,828.36	26.26	40.00	0.94480	558,212
1988	602,089.83	27.15	40.00	0.88317	531,745
1989	488,245.35	28.06	40.00	0.82080	400,750
1990	559,464.73	28.98	40.00	0.75786	423,995
1991	767,360.71	29.90	40.00	0.69426	532,748
1992	916,571.93	30.83	40.00	0.63016	577,584
1993	1,052,736.78	31.77	40.00	0.56547	595,296
1994	2,190,703.67	32.72	40.00	0.50036	1,096,130
1995	1,029,959.54	33.68	40.00	0.43474	447,768
1996	1,373,719.44	34.64	40.00	0.36876	506,573
1997	1,414,127.73	35.60	40.00	0.30237	427,585

Montana-Dakota Utilities Company
Gas Division
380.20 SERVICES - PLASTIC
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -175 % Average Service Life: 40 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1998	1,295,966.64	36.57	40.00	0.23567	305,420
1999	1,016,375.00	37.55	40.00	0.16864	171,402
2000	1,150,408.62	38.53	40.00	0.10137	116,615
2001	1,245,592.79	39.51	40.00	0.03384	42,147
Total	24,580,506.89				18,553,187.58

Montana-Dakota Utilities Company
Gas Division
380.30 SERVICES - FARM & FUEL LINES
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -175 % Average Service Life: 30 Survivor Curve: R1.5

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1977	681.71	12.49	30.00	1.60500	1,094
1980	6,866.04	14.25	30.00	1.44336	9,910
1981	9,184.73	14.87	30.00	1.38660	12,736
1982	34,432.20	15.51	30.00	1.32859	45,746
1983	7,969.08	16.15	30.00	1.26930	10,115
1984	18,901.15	16.81	30.00	1.20870	22,846
1985	13,311.43	17.49	30.00	1.14699	15,268
1986	1,610.76	18.17	30.00	1.08417	1,746
1987	1,964.42	18.87	30.00	1.02020	2,004
1988	9,854.82	19.58	30.00	0.95528	9,414
1989	1,711.71	20.30	30.00	0.88943	1,522
1991	3,912.84	21.76	30.00	0.75498	2,954
1992	4,904.22	22.51	30.00	0.68658	3,367
1993	1,286.17	23.27	30.00	0.61735	794
1994	63,263.97	24.03	30.00	0.54743	34,633
1997	18,107.93	26.36	30.00	0.33328	6,035
1998	3,815.98	27.16	30.00	0.26048	994
1999	2,163.03	27.96	30.00	0.18691	404
2000	5,016.54	28.77	30.00	0.11268	565
2001	3,381.69	29.59	30.00	0.03776	128
Total	212,340 42				182,276.33

Montana-Dakota Utilities Company
Gas Division
391.10 OFFICE FURNITURE & EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 5% Average Service Life: 15 Survivor Curve: R1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1932	4,605.04	0.00	0.00	0.95000	4,375
1933	4,720.16	0.00	0.00	0.95000	4,484
1934	4,838.17	0.00	0.00	0.95000	4,596
1935	572.05	0.00	0.00	0.95000	543
1936	1,095.98	0.00	0.00	0.95000	1,041
1937	1,223.06	0.00	0.00	0.95000	1,162
1938	1,353.31	0.00	0.00	0.95000	1,286
1939	1,486.82	0.00	0.00	0.95000	1,412
1940	1,623.67	0.00	0.00	0.95000	1,542
1946	1,623.67	0.00	0.00	0.95000	1,542
1947	1,623.67	0.00	0.00	0.95000	1,542
1948	1,623.67	0.00	0.00	0.95000	1,542
1949	1,623.67	0.00	0.00	0.95000	1,542
1950	1,981.49	0.00	0.00	0.95000	1,882
1951	8,252.35	0.00	0.00	0.95000	7,840
1952	10,124.49	0.00	0.00	0.95000	9,618
1953	1,675.30	0.00	0.00	0.95000	1,592
1954	5,978.65	0.00	0.00	0.95000	5,680
1955	11,466.37	0.00	0.00	0.95000	10,893
1956	15,979.68	0.00	0.00	0.95000	15,181
1957	4,672.90	0.00	0.00	0.95000	4,439
1958	2,895.25	0.00	0.00	0.95000	2,750
1959	8,266.43	0.00	0.00	0.95000	7,853
1960	12,190.08	0.00	0.00	0.95000	11,581
1961	6,523.95	0.00	0.00	0.95000	6,198
1962	11,986.55	0.00	0.00	0.95000	11,387
1963	6,144.10	0.00	0.00	0.95000	5,837
1964	12,954.93	0.00	0.00	0.95000	12,307

Montana-Dakota Utilities Company
Gas Division
391.10 OFFICE FURNITURE & EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 5% Average Service Life: 15 Survivor Curve: R1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1965	7,103.42	0.00	0.00	0.95000	6,748
1966	12,419.03	0.00	0.00	0.95000	11,798
1967	8,319.57	0.00	0.00	0.95000	7,904
1968	9,375.91	0.00	0.00	0.95000	8,907
1969	6,998.56	0.00	0.00	0.95000	6,649
1970	4,090.25	0.00	0.00	0.95000	3,886
1971	11,362.05	0.00	0.00	0.95000	10,794
1972	10,984.80	0.50	15.00	0.91834	10,088
1973	10,930.76	0.65	15.00	0.90911	9,937
1974	9,787.88	0.94	15.00	0.89037	8,715
1975	8,735.36	1.23	15.00	0.87208	7,618
1976	5,040.24	1.52	15.00	0.85399	4,304
1977	4,684.21	1.81	15.00	0.83510	3,912
1978	5,546.27	2.13	15.00	0.81519	4,521
1979	12,021.50	2.46	15.00	0.79433	9,549
1980	18,723.22	2.80	15.00	0.77239	14,462
1981	24,944.34	3.17	15.00	0.74932	18,691
1982	26,742.13	3.55	15.00	0.72514	19,392
1983	23,687.42	3.95	15.00	0.69975	16,575
1984	16,424.42	4.37	15.00	0.67311	11,056
1985	11,667.33	4.81	15.00	0.64517	7,527
1986	6,298.35	5.28	15.00	0.61586	3,879
1987	10,031.76	5.76	15.00	0.58515	5,870
1988	6,004.27	6.27	15.00	0.55297	3,320
1989	6,111.73	6.80	15.00	0.51931	3,174
1990	5,969.99	7.36	15.00	0.48419	2,891
1991	34,027.99	7.93	15.00	0.44760	15,231
1992	3,510.40	8.53	15.00	0.40961	1,438

Montana-Dakota Utilities Company

Gas Division

391.10 OFFICE FURNITURE & EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 5% Average Service Life: 15 Survivor Curve: R1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1993	19,099.32	9.15	15.00	0.37032	7,073
1994	12,943.96	9.79	15.00	0.32984	4,269
1995	8,216.74	10.45	15.00	0.28833	2,369
1996	12,579.64	11.12	15.00	0.24598	3,094
1997	2,820.08	11.80	15.00	0.20290	572
1998	2,737.78	12.49	15.00	0.15918	436
1999	5,933.10	13.19	15.00	0.11477	681
2000	8,854.29	13.90	15.00	0.06954	616
2001	441.08	14.63	15.00	0.02342	10
Total	544,274.61				399,605.71

Montana-Dakota Utilities Company

Gas Division

393.00 STORES EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 35 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1920	876.54	0.00	0.00	1.00000	877
1921	898.45	0.00	0.00	1.00000	898
1922	920.91	0.00	0.00	1.00000	921
1923	943.94	0.00	0.00	1.00000	944
1924	967.54	0.00	0.00	1.00000	968
1925	991.73	0.00	0.00	1.00000	992
1926	1,016.52	0.00	0.00	1.00000	1,017
1927	1,041.94	0.00	0.00	1.00000	1,042
1928	1,067.99	0.00	0.00	1.00000	1,068
1929	1,094.69	0.00	0.00	1.00000	1,095
1930	1,122.06	0.00	0.00	1.00000	1,122
1931	1,150.10	0.00	0.00	1.00000	1,150
1932	1,178.86	0.00	0.00	1.00000	1,179
1933	1,208.33	0.00	0.00	1.00000	1,208
1934	1,238.54	0.00	0.00	1.00000	1,239
1935	1,269.50	0.00	0.00	1.00000	1,270
1936	1,301.23	0.00	0.00	1.00000	1,301
1937	1,333.76	0.00	0.00	1.00000	1,334
1938	1,367.11	0.00	0.00	1.00000	1,367
1939	1,401.28	0.00	0.00	1.00000	1,401
1940	1,436.32	0.00	0.00	1.00000	1,436
1946	1,436.32	0.95	35.00	0.97277	1,397
1947	1,436.32	1.16	35.00	0.96684	1,389
1948	1,436.32	1.39	35.00	0.96021	1,379
1949	789.40	1.64	35.00	0.95325	752
1950	1,517.02	1.89	35.00	0.94610	1,435
1951	1,573.73	2.14	35.00	0.93885	1,478
1952	1,603.23	2.40	35.00	0.93155	1,493

Montana-Dakota Utilities Company
Gas Division
393.00 STORES EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 35 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1953	981.21	2.66	35.00	0.92407	907
1954	734.17	2.91	35.00	0.91687	673
1955	7,012.16	3.16	35.00	0.90957	6,378
1956	6,292.92	3.42	35.00	0.90215	5,677
1957	1,071.47	3.69	35.00	0.89454	958
1958	4,692.97	3.97	35.00	0.88666	4,161
1959	430.38	4.26	35.00	0.87842	378
1960	2,526.36	4.56	35.00	0.86968	2,197
1961	553.94	4.88	35.00	0.86053	477
1962	1,082.68	5.22	35.00	0.85076	921
1963	1,045.67	5.59	35.00	0.84034	879
1964	485.33	5.98	35.00	0.82920	402
1965	9,479.05	6.39	35.00	0.81734	7,748
1966	2,157.35	6.84	35.00	0.80471	1,736
1967	1,651.60	7.30	35.00	0.79133	1,307
1968	5,567.94	7.80	35.00	0.77714	4,327
1969	516.52	8.32	35.00	0.76217	394
1970	8,797.44	8.87	35.00	0.74644	6,567
1971	9,040.24	9.45	35.00	0.72997	6,599
1972	2,993.64	10.05	35.00	0.71279	2,134
1973	5,710.69	10.68	35.00	0.69493	3,969
1974	2,278.09	11.32	35.00	0.67647	1,541
1975	967.22	11.99	35.00	0.65734	636
1977	2,974.56	13.39	35.00	0.61735	1,836
1978	7,363.43	14.12	35.00	0.59657	4,393
1980	2,475.39	15.63	35.00	0.55352	1,370
1982	608.44	17.20	35.00	0.50867	309
1986	2,247.72	20.52	35.00	0.41386	930

Montana-Dakota Utilities Company

Gas Division

393.00 STORES EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 35 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1987	12,024.02	21.38	35.00	0.38918	4,680
1990	761.71	24.04	35.00	0.31308	238
1992	14,689.00	25.87	35.00	0.26074	3,830
1993	852.74	26.80	35.00	0.23415	200
1994	11,358.34	27.74	35.00	0.20731	2,355
1996	1,284.52	29.65	35.00	0.15296	196
2000	697.76	33.53	35.00	0.04211	29
2001	19,702.69	34.51	35.00	0.01406	277
Total	186,729.04				114,760.65

Montana-Dakota Utilities Company

Gas Division

394.10 TOOLS, SHOP & GARAGE EQ. - NON-UNITIZED

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 10% Average Service Life: 18 Survivor Curve: R1.5

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1974	36,622.46	2.44	18.00	0.77800	28,492
1975	31,287.00	2.72	18.00	0.76412	23,907
1976	38,526.15	3.01	18.00	0.74954	28,877
1977	43,861.56	3.31	18.00	0.73439	32,212
1978	49,851.04	3.63	18.00	0.71842	35,814
1979	79,790.49	3.97	18.00	0.70157	55,978
1980	65,439.00	4.33	18.00	0.68360	44,734
1981	45,439.51	4.71	18.00	0.66439	30,190
1982	145,545.11	5.12	18.00	0.64384	93,707
1983	159,927.81	5.56	18.00	0.62187	99,454
1984	97,782.23	6.03	18.00	0.59843	58,516
1985	141,942.76	6.53	18.00	0.57356	81,412
1986	84,211.26	7.06	18.00	0.54720	46,081
1987	14,238.35	7.61	18.00	0.51947	7,396
1988	20,503.70	8.19	18.00	0.49034	10,054
1989	45,044.89	8.80	18.00	0.45993	20,717
1990	36,693.43	9.43	18.00	0.42830	15,716
1991	24,443.91	10.09	18.00	0.39550	9,668
1992	53,567.54	10.77	18.00	0.36165	19,373
1993	10,028.74	11.46	18.00	0.32679	3,277
1994	206,999.56	12.18	18.00	0.29104	60,246
1995	9,864.87	12.91	18.00	0.25446	2,510
1996	69,879.57	13.66	18.00	0.21715	15,175
1997	66,862.98	14.42	18.00	0.17914	11,978
1998	66,108.46	15.19	18.00	0.14047	9,286
1999	60,557.07	15.98	18.00	0.10115	6,125
2000	93,753.78	16.78	18.00	0.06117	5,735
2001	88,425.17	17.59	18.00	0.02055	1,818

Montana-Dakota Utilities Company
Gas Division
394.10 TOOLS, SHOP & GARAGE EQ. - NON-UNITIZED
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 10% Average Service Life: 18 Survivor Curve: R1.5

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1946	2,768.79	0.00	0.00	0.90000	2,492
1947	10,474.25	0.00	0.00	0.90000	9,427
1948	10,474.25	0.00	0.00	0.90000	9,427
1949	20,648.04	0.00	0.00	0.90000	18,583
1950	17,472.71	0.00	0.00	0.90000	15,725
1951	15,341.30	0.00	0.00	0.90000	13,807
1952	11,046.82	0.00	0.00	0.90000	9,942
1953	10,454.96	0.00	0.00	0.90000	9,409
1954	5,192.39	0.00	0.00	0.90000	4,673
1955	32,433.75	0.00	0.00	0.90000	29,190
1956	19,335.83	0.00	0.00	0.90000	17,402
1957	12,341.13	0.00	0.00	0.90000	11,107
1958	13,607.12	0.00	0.00	0.90000	12,246
1959	12,214.77	0.00	0.00	0.90000	10,993
1960	22,642.61	0.00	0.00	0.90000	20,378
1961	18,282.80	0.00	0.00	0.90000	16,455
1962	26,929.12	0.00	0.00	0.90000	24,236
1963	24,298.85	0.00	0.00	0.90000	21,869
1964	34,075.59	0.00	0.00	0.90000	30,668
1965	30,108.83	0.00	0.00	0.90000	27,098
1966	22,527.64	0.50	18.00	0.87500	19,712
1967	10,291.19	0.66	18.00	0.86705	8,923
1968	19,981.37	0.95	18.00	0.85234	17,031
1969	19,473.45	1.25	18.00	0.83774	16,314
1970	67,277.41	1.48	18.00	0.82624	55,587
1971	18,320.87	1.69	18.00	0.81530	14,937
1972	59,710.82	1.93	18.00	0.80369	47,989
1973	40,496.89	2.17	18.00	0.79131	32,045

Montana-Dakota Utilities Company

Gas Division

394.10 TOOLS, SHOP & GARAGE EQ. - NON-UNITIZED

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 10% Average Service Life: 18 Survivor Curve: R1.5

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
Total	2,495,421.95				1,386,114.00

Montana-Dakota Utilities Company
Gas Division
394.20 TOOLS, SHOP & GARAGE EQ. - UNITIZED
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 18 Survivor Curve: R1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1962	6,990.28	0.00	0.00	1.00000	6,990
1963	70,494.67	0.00	0.00	1.00000	70,495
1964	2,415.75	0.00	0.00	1.00000	2,416
1965	5,511.69	0.00	0.00	1.00000	5,512
1966	7,731.14	0.50	18.00	0.97222	7,516
1967	7,378.96	0.66	18.00	0.96339	7,109
1968	231.79	0.95	18.00	0.94704	220
1969	399.89	1.26	18.00	0.93020	372
1970	7,827.19	1.54	18.00	0.91432	7,157
1971	15,509.28	1.83	18.00	0.89814	13,930
1972	10,484.48	2.14	18.00	0.88138	9,241
1973	4,954.02	2.45	18.00	0.86403	4,280
1974	4,004.35	2.77	18.00	0.84590	3,387
1975	5,920.17	3.11	18.00	0.82708	4,896
1976	998.41	3.47	18.00	0.80743	806
1977	1,027.64	3.83	18.00	0.78702	809
1978	2,122.39	4.22	18.00	0.76575	1,625
1979	4,411.03	4.61	18.00	0.74364	3,280
1980	3,423.85	5.03	18.00	0.72061	2,467
1981	12,514.37	5.46	18.00	0.69666	8,718
1982	7,684.76	5.91	18.00	0.67173	5,162
1983	11,708 73	6.38	18.00	0.64580	7,561
1984	1,854.49	6.86	18.00	0.61883	1,148
1985	12,563.97	7.37	18.00	0.59081	7,423
1986	6,836.77	7.89	18.00	0.56170	3,840
1987	7,476.49	8.43	18.00	0.53154	3,974
1988	12,360.85	9.00	18.00	0.50026	6,184
1989	4,744.93	9.58	18.00	0.46794	2,220

Montana-Dakota Utilities Company
Gas Division
394.20 TOOLS, SHOP & GARAGE EQ. - UNITIZED
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 18 Survivor Curve: R1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1990	2,357.99	10.18	18.00	0.43462	1,025
1991	10,567.32	10.80	18.00	0.40032	4,230
1992	9,564.80	11.43	18.00	0.36514	3,493
1993	11,753.78	12.08	18.00	0.32915	3,869
1994	12,528.52	12.74	18.00	0.29248	3,664
1995	1,060.27	13.41	18.00	0.25519	271
1996	7,303.76	14.09	18.00	0.21741	1,588
1997	1,590.72	14.78	18.00	0.17915	285
1998	431.11	15.47	18.00	0.14040	61
2000	3,069.32	16.90	18.00	0.06116	188
Total	299,809.93				217,410.85

Montana-Dakota Utilities Company
Gas Division
394.30 VEHICLE MAINTENANCE EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *20* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1987	5,304.03	7.30	20.00	0.63504	3,368
1989	3,393.19	8.77	20.00	0.56171	1,906
1991	8,613.81	10.35	20.00	0.48264	4,157
1992	261.32	11.18	20.00	0.44113	115
1993	1,728.56	12.03	20.00	0.39848	689
1994	11,875.67	12.91	20.00	0.35466	4,212
Total	31,176.58				14,447.48

Montana-Dakota Utilities Company
Gas Division
394.40 VEHICLE REFUELING EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *15* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1986	168,496.74	2.82	15.00	0.81230	136,870
1988	6,891.99	3.81	15.00	0.74592	5,141
1991	123,192.75	5.74	15.00	0.61713	76,026
1992	2,120.12	6.48	15.00	0.56791	1,204
1993	2,061.06	7.26	15.00	0.51615	1,064
1994	10,966.22	8.07	15.00	0.46197	5,066
1995	547.21	8.92	15.00	0.40561	222
1996	47,065.32	9.79	15.00	0.34724	16,343
1997	2.59	10.69	15.00	0.28702	1
Total	361,344.00				241,936.53

Montana-Dakota Utilities Company
Gas Division
395.00 LABORATORY EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 20 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1917	248.19	0.00	0.00	1.00000	248
1918	254.40	0.00	0.00	1.00000	254
1919	260.76	0.00	0.00	1.00000	261
1920	267.28	0.00	0.00	1.00000	267
1921	273.96	0.00	0.00	1.00000	274
1922	280.81	0.00	0.00	1.00000	281
1923	287.83	0.00	0.00	1.00000	288
1924	295.03	0.00	0.00	1.00000	295
1925	302.41	0.00	0.00	1.00000	302
1926	309.97	0.00	0.00	1.00000	310
1927	317.72	0.00	0.00	1.00000	318
1928	325.66	0.00	0.00	1.00000	326
1929	333.80	0.00	0.00	1.00000	334
1930	342.15	0.00	0.00	1.00000	342
1931	350.70	0.00	0.00	1.00000	351
1932	359.47	0.00	0.00	1.00000	359
1933	368.45	0.00	0.00	1.00000	368
1934	377.66	0.00	0.00	1.00000	378
1935	387.11	0.00	0.00	1.00000	387
1936	396.79	0.00	0.00	1.00000	397
1937	406.71	0.00	0.00	1.00000	407
1938	416.87	0.00	0.00	1.00000	417
1939	427.29	0.00	0.00	1.00000	427
1940	437.98	0.00	0.00	1.00000	438
1946	437.98	0.00	0.00	1.00000	438
1947	437.98	0.00	0.00	1.00000	438
1948	437.98	0.00	0.00	1.00000	438
1949	1.89	0.00	0.00	1.00000	2

Montana-Dakota Utilities Company
Gas Division
395.00 LABORATORY EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 20 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1950	2,564.04	0.00	0.00	1.00000	2,564
1951	1,039.70	0.00	0.00	1.00000	1,040
1952	805.50	0.00	0.00	1.00000	806
1953	902.82	0.00	0.00	1.00000	903
1954	553.05	0.00	0.00	1.00000	553
1955	4,836.21	0.00	0.00	1.00000	4,836
1956	8,088.70	0.00	0.00	1.00000	8,089
1957	1,095.26	0.00	0.00	1.00000	1,095
1958	1,522.91	0.00	0.00	1.00000	1,523
1959	1,655.38	0.00	0.00	1.00000	1,655
1960	1,919.08	0.00	0.00	1.00000	1,919
1961	842.89	0.00	0.00	1.00000	843
1962	2,970.42	0.00	0.00	1.00000	2,970
1963	3,206.92	0.00	0.00	1.00000	3,207
1964	3,565.69	0.00	0.00	1.00000	3,566
1965	8,297.31	0.50	20.00	0.97500	8,090
1966	1,670.45	0.55	20.00	0.97229	1,624
1967	2,548.34	0.78	20.00	0.96110	2,449
1968	6,293.85	1.02	20.00	0.94902	5,973
1969	7,085.19	1.29	20.00	0.93532	6,627
1970	5,535.63	1.57	20.00	0.92162	5,102
1971	232.62	1.86	20.00	0.90725	211
1972	412.89	2.14	20.00	0.89307	369
1973	500.58	2.43	20.00	0.87844	440
1974	619.36	2.73	20.00	0.86373	535
1975	894.69	3.03	20.00	0.84832	759
1976	175.42	3.35	20.00	0.83233	146
1977	870.65	3.69	20.00	0.81528	710

Montana-Dakota Utilities Company
Gas Division
395.00 LABORATORY EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 20 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1978	872.35	4.06	20.00	0.79716	695
1979	199.29	4.45	20.00	0.77773	155
1980	26,430.61	4.86	20.00	0.75693	20,006
1981	3,784.36	5.31	20.00	0.73469	2,780
1982	15,487.05	5.78	20.00	0.71096	11,011
1983	14,023.78	6.28	20.00	0.68576	9,617
1984	2,706.78	6.82	20.00	0.65901	1,784
1985	17,869.81	7.38	20.00	0.63087	11,273
1987	17,045.88	8.59	20.00	0.57030	9,721
1988	1,235.97	9.24	20.00	0.53797	665
1989	1,656.98	9.91	20.00	0.50445	836
1990	522.68	10.61	20.00	0.46966	245
1991	14,199.27	11.32	20.00	0.43380	6,160
1992	1,179.16	12.06	20.00	0.39677	468
1993	21,838.03	12.82	20.00	0.35877	7,835
1994	2,203.93	13.61	20.00	0.31972	705
1995	20,858.40	14.40	20.00	0.27977	5,836
1996	1,164.44	15.22	20.00	0.23890	278
2000	22,599.05	18.65	20.00	0.06729	1,521
2001	5,104.87	19.55	20.00	0.02260	115
Total	271,033.07				169,653.55

Montana-Dakota Utilities Company
Gas Division
397.10 COMMUNICATION EQUIP. - FIXED RADIOS
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *15* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1991	283,409.44	5.74	15.00	0.61713	174,901
1992	71,130.42	6.48	15.00	0.56791	40,396
1993	23,122.18	7.26	15.00	0.51615	11,934
1994	10,283.52	8.07	15.00	0.46197	4,751
1995	36,113.02	8.92	15.00	0.40561	14,648
1996	19,525.74	9.79	15.00	0.34724	6,780
1997	17,886.14	10.69	15.00	0.28702	5,134
1998	1,719.80	11.62	15.00	0.22521	387
2001	18,464.91	14.51	15.00	0.03277	605
Total	481,655.17				259,536.01

Montana-Dakota Utilities Company

Gas Division

397.20 COMMUNICATION EQUIP. - MOBILE RADIOS

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *15* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	275,814.98	6.48	15.00	0.56791	156,639
1993	14,099.41	7.26	15.00	0.51615	7,277
1994	14,961.40	8.07	15.00	0.46197	6,912
1995	18,861.62	8.92	15.00	0.40561	7,650
1996	11,115.37	9.79	15.00	0.34724	3,860
1997	7,034.48	10.69	15.00	0.28702	2,019
1998	2,166.65	11.62	15.00	0.22521	488
2000	57,474.34	13.53	15.00	0.09783	5,623
Total	401,528.25				190,468.35

Montana-Dakota Utilities Company
Gas Division
397.30 TELEPHONE COMMUNICATION EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 10 Survivor Curve: R1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1962	10,198.28	0.00	0.00	1.00000	10,198
1966	52.39	0.00	0.00	1.00000	52
1969	23.80	0.00	0.00	1.00000	24
1971	3,948.33	0.00	0.00	1.00000	3,948
1972	415.51	0.00	0.00	1.00000	416
1975	1,189.52	0.00	0.00	1.00000	1,190
1978	768.91	0.00	0.00	1.00000	769
1981	71.37	0.00	0.00	1.00000	71
1982	433.48	0.50	10.00	0.95001	412
1983	2,183.65	0.64	10.00	0.93616	2,044
1984	10,228.48	0.91	10.00	0.90937	9,301
1985	10,278.46	1.19	10.00	0.88125	9,058
1986	1,982.55	1.49	10.00	0.85059	1,686
1987	5,038.22	1.83	10.00	0.81726	4,118
1988	7,206.19	2.19	10.00	0.78120	5,629
1989	2,283.76	2.58	10.00	0.74233	1,695
1990	2,063.91	3.00	10.00	0.70047	1,446
1991	524.46	3.45	10.00	0.65545	344
1992	3,159.48	3.93	10.00	0.60707	1,918
1993	2,658.67	4.45	10.00	0.55522	1,476
1994	979.46	5.00	10.00	0.49984	490
1995	12,575.53	5.59	10.00	0.44104	5,546
1996	6,166.38	6.21	10.00	0.37907	2,337
1997	3,155.57	6.86	10.00	0.31438	992
1998	236.42	7.53	10.00	0.24754	59
1999	2,436.85	8.21	10.00	0.17906	436
2000	258.23	8.91	10.00	0.10895	28
Total	90,517.86				65,684.23

Montana-Dakota Utilities Company

Gas Division

397.50 SUPERVISORY & TELEMETERING EQUIP.

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 10 Survivor Curve: L1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1962	863.27	0.00	0.00	1.00000	863
1965	2,642.62	0.00	0.00	1.00000	2,643
1966	11,891.31	0.00	0.00	1.00000	11,891
1967	4,291.05	0.00	0.00	1.00000	4,291
1968	29,863.13	0.00	0.00	1.00000	29,863
1969	8,557.59	0.00	0.00	1.00000	8,558
1970	11,454.18	0.00	0.00	1.00000	11,454
1971	3,626.38	0.50	10.00	0.95001	3,445
1972	682.29	0.60	10.00	0.94018	641
1973	1,033.02	0.72	10.00	0.92812	959
1974	1,108.55	0.86	10.00	0.91415	1,013
1975	1,736.12	1.01	10.00	0.89901	1,561
1976	180.57	1.17	10.00	0.88299	159
1978	165.31	1.51	10.00	0.84872	140
1979	2,889.31	1.69	10.00	0.83056	2,400
1980	2,034.47	1.88	10.00	0.81171	1,651
1981	2,791.32	2.08	10.00	0.79215	2,211
1982	3,535.81	2.28	10.00	0.77186	2,729
1983	19,276.85	2.49	10.00	0.75077	14,473
1984	3,943.41	2.71	10.00	0.72886	2,874
1987	2,698.10	3.43	10.00	0.65745	1,774
1988	4,097.32	3.69	10.00	0.63152	2,588
1990	3,680.20	4.24	10.00	0.57592	2,120
1991	1.07	4.54	10.00	0.54605	1
1992	666.97	4.85	10.00	0.51463	343
1993	56.96	5.19	10.00	0.48155	27
1994	189.71	5.53	10.00	0.44665	85
1995	210.27	5.90	10.00	0.40980	86

Montana-Dakota Utilities Company

Gas Division

397.50 SUPERVISORY & TELEMETERING EQUIP.

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 10 Survivor Curve: L1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
Total	124,167.16				110,843.64

Montana-Dakota Utilities Company
Gas Division
397.60 SCADA SYSTEM

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *8* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1982	20,454.51	0.00	0.00	1.00000	20,455
1983	272.42	0.00	0.00	1.00000	272
1988	9,732.20	0.00	0.00	1.00000	9,732
1991	7.00	0.83	8.00	0.89574	6
1992	424.05	1.09	8.00	0.86365	366
1993	4.17	1.43	8.00	0.82138	3
Total	30,894.35				30,835.06

Montana-Dakota Utilities Company
Gas Division
397.80 NETWORK EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *5* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1997	20,086.86	1.30	5.00	0.74081	14,881
1998	71.16	1.93	5.00	0.61498	44
2000	2,960.82	3.57	5.00	0.28673	849
2001	7,218.71	4.51	5.00	0.09781	706
Total	30,337.55				16,479.36

Montana-Dakota Utilities Company
Gas Division
398.00 MISCELLANEOUS EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 20 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1919	1,799.43	0.00	0.00	1.00000	1,799
1920	1,844.42	0.00	0.00	1.00000	1,844
1921	1,890.54	0.00	0.00	1.00000	1,891
1922	1,937.81	0.00	0.00	1.00000	1,938
1923	1,986.26	0.00	0.00	1.00000	1,986
1924	2,035.91	0.00	0.00	1.00000	2,036
1925	2,086.81	0.00	0.00	1.00000	2,087
1926	2,138.98	0.00	0.00	1.00000	2,139
1927	2,192.46	0.00	0.00	1.00000	2,192
1928	2,247.27	0.00	0.00	1.00000	2,247
1929	2,303.46	0.00	0.00	1.00000	2,303
1930	2,361.04	0.00	0.00	1.00000	2,361
1931	2,420.07	0.00	0.00	1.00000	2,420
1932	2,480.57	0.00	0.00	1.00000	2,481
1933	2,542.58	0.00	0.00	1.00000	2,543
1934	2,606.15	0.00	0.00	1.00000	2,606
1935	2,671.31	0.00	0.00	1.00000	2,671
1936	2,738.09	0.00	0.00	1.00000	2,738
1937	2,806.55	0.00	0.00	1.00000	2,807
1938	2,670.74	0.00	0.00	1.00000	2,671
1939	1,504.70	0.00	0.00	1.00000	1,505
1940	1,578.42	0.00	0.00	1.00000	1,578
1946	1,578.42	0.00	0.00	1.00000	1,578
1947	1,578.42	0.00	0.00	1.00000	1,578
1948	75.51	0.00	0.00	1.00000	76
1949	712.06	0.00	0.00	1.00000	712
1950	18.87	0.00	0.00	1.00000	19
1951	1,511.40	0.00	0.00	1.00000	1,511

Montana-Dakota Utilities Company
Gas Division
398.00 MISCELLANEOUS EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 20 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1952	983.55	0.00	0.00	1.00000	984
1953	293.80	0.00	0.00	1.00000	294
1954	927.89	0.00	0.00	1.00000	928
1955	1,525.46	0.00	0.00	1.00000	1,525
1956	3,052.88	0.00	0.00	1.00000	3,053
1957	1,217.33	0.00	0.00	1.00000	1,217
1958	377.32	0.00	0.00	1.00000	377
1959	169.89	0.00	0.00	1.00000	170
1960	496.66	0.00	0.00	1.00000	497
1961	59.51	0.00	0.00	1.00000	60
1962	520.05	0.00	0.00	1.00000	520
1963	426.66	0.00	0.00	1.00000	427
1964	942.69	0.00	0.00	1.00000	943
1965	1,709.06	0.50	20.00	0.97500	1,666
1966	78.17	0.55	20.00	0.97229	76
1967	3,942.75	0.78	20.00	0.96110	3,789
1968	271.95	1.02	20.00	0.94902	258
1969	189.56	1.29	20.00	0.93532	177
1970	1,608.17	1.57	20.00	0.92162	1,482
1971	3,776.19	1.86	20.00	0.90725	3,426
1972	7,021.13	2.14	20.00	0.89307	6,270
1973	1,865.72	2.43	20.00	0.87844	1,639
1974	2,021.54	2.73	20.00	0.86373	1,746
1975	642.76	3.03	20.00	0.84832	545
1976	526.83	3.35	20.00	0.83233	438
1977	4,506.09	3.69	20.00	0.81528	3,674
1978	3,546.17	4.06	20.00	0.79716	2,827
1979	1,977.23	4.45	20.00	0.77773	1,538

Montana-Dakota Utilities Company

Gas Division

398.00 MISCELLANEOUS EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 20 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1980	1,401.81	4.86	20.00	0.75693	1,061
1981	1,047.93	5.31	20.00	0.73469	770
1982	517.45	5.78	20.00	0.71096	368
1983	2,336.29	6.28	20.00	0.68576	1,602
1984	940.17	6.82	20.00	0.65901	620
1985	1,072.89	7.38	20.00	0.63087	677
1986	150.93	7.98	20.00	0.60123	91
1988	259.43	9.24	20.00	0.53797	140
1989	512.29	9.91	20.00	0.50445	258
1990	1,079.95	10.61	20.00	0.46966	507
1991	2,406.18	11.32	20.00	0.43380	1,044
1992	3,002.27	12.06	20.00	0.39677	1,191
1993	2,104.05	12.82	20.00	0.35877	755
1994	20,986.12	13.61	20.00	0.31972	6,710
1996	2,257.88	15.22	20.00	0.23890	539
1997	1,968.54	16.06	20.00	0.19718	388
1998	2,379.33	16.91	20.00	0.15462	368
2000	493.66	18.65	20.00	0.06729	33
2001	1,357.13	19.55	20.00	0.02260	31
Total	145,269.56				112,016.70

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 374.1 - Rights of Way

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	1,754.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001.

Account 374.1 - Rights of Way

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	1,754.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	1,754.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	1,754.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	1,754.13	0.00	0.00%	0.00	0.00%	0.00	0.00%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	50
Avg Ret Age	24.9
Years to ASL	25.1
Inflation Factor At 2.75% to ASL	1.98

Gross Salv. Trend Analysis*		
1982-2001	20-Year Tren	0.00%
1987-2001	15-Year Tren	0.00%
1992-2001	10-Year Tren	0.00%
1997-2001	5-Year Tren	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**0.00%**	**0.00%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 375 - Structures & Improvements

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	3,425.08	435.45	12.71%	230.31	6.72%	205.14	5.99%
1969	4,310.44	819.74	19.02%	656.20	15.22%	163.54	3.79%
1970	4,433.29	1,076.90	24.29%	450.82	10.17%	626.08	14.12%
1971	2,081.69	883.96	42.46%	48.83	2.35%	835.13	40.12%
1972	2,058.30	0.00	0.00%	19.89	0.97%	(19.89)	-0.97%
1973	1,012.35	0.00	0.00%	59.26	5.85%	(59.26)	-5.85%
1974	3,269.04	2,424.62	74.17%	246.45	7.54%	2,178.17	66.63%
1975	1,584.93	98.73	6.23%	470.32	29.67%	(371.59)	-23.45%
1976	2,446.53	0.00	0.00%	166.82	6.82%	(166.82)	-6.82%
1977	661.00	0.00	0.00%	144.69	21.89%	(144.69)	-21.89%
1978	1,605.72	0.00	0.00%	875.01	54.49%	(875.01)	-54.49%
1979	303.10	0.00	0.00%	19.22	6.34%	(19.22)	-6.34%
1980	1,134.17	0.00	0.00%	627.51	55.33%	(627.51)	-55.33%
1981	1,442.23	0.00	0.00%	230.47	15.98%	(230.47)	-15.98%
1982	2,256.89	0.00	0.00%	609.90	27.02%	(609.90)	-27.02%
1983		0.00	0.00%		0.00%	0.00	0.00%
1984	628.89	0.00	0.00%		0.00%	0.00	0.00%
1985	2,049.04	1,096.13	53.49%	733.70	35.81%	362.43	17.69%
1986	1,006.41	(620.46)	-61.65%	781.10	77.61%	(1,401.56)	-139.26%
1987	891.58	0.00	0.00%	83.33	9.35%	(83.33)	-9.35%
1988	457.00	0.00	0.00%		0.00%	0.00	0.00%
1989	1,618.28	1.00	0.06%	448.28	27.70%	(447.28)	-27.64%
1990	773.00	0.00	0.00%	523.47	67.72%	(523.47)	-67.72%
1991	3,506.79	0.00	0.00%	2,521.31	71.90%	(2,521.31)	-71.90%
1992	3,956.71	0.00	0.00%	2,552.03	64.50%	(2,552.03)	-64.50%
1993	3,366.82	0.00	0.00%	1,633.72	48.52%	(1,633.72)	-48.52%
1994	5,438.75	0.00	0.00%	2,211.80	40.67%	(2,211.80)	-40.67%
1995	247.53	4,904.42	1981.34%	734.55	296.75%	4,169.87	1684.59%
1996	3122.98	0.00	0.00%	4,739.85	151.77%	(4,739.85)	-151.77%
1997	5835.64	850.00	14.57%	257.00	4.40%	593.00	10.16%
1998	150.63	0.00	0.00%	600.00	398.33%	(600.00)	-398.33%
1999	454.69	0.00	0.00%	4,286.94	942.83%	(4,286.94)	-942.83%
2000	3897.84	1.00	0.03%	2,219.11	56.93%	(2,218.11)	-56.91%
2001	786.50	0.00	0.00%	2,596.09	330.08%	(2,596.09)	-330.08%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 375 - Structures & Improvements

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	12168.81	2,332.09	19.16%	1,337.33	10.99%	994.76	8.17%
1969-1971	10825.42	2,780.60	25.69%	1,155.85	10.68%	1,624.75	15.01%
1970-1972	8573.28	1,960.86	22.87%	519.54	6.06%	1,441.32	16.81%
1971-1973	5152.34	883.96	17.16%	127.98	2.48%	755.98	14.67%
1972-1974	6339.69	2,424.62	38.25%	325.60	5.14%	2,099.02	33.11%
1973-1975	5866.32	2,523.35	43.01%	776.03	13.23%	1,747.32	29.79%
1974-1976	7300.50	2,523.35	34.56%	883.59	12.10%	1,639.76	22.46%
1975-1977	4692.46	98.73	2.10%	781.83	16.66%	(683.10)	-14.56%
1976-1978	4713.25	0.00	0.00%	1,186.52	25.17%	(1,186.52)	-25.17%
1977-1979	2569.82	0.00	0.00%	1,038.92	40.43%	(1,038.92)	-40.43%
1978-1980	3042.99	0.00	0.00%	1,521.74	50.01%	(1,521.74)	-50.01%
1979-1981	2879.50	0.00	0.00%	877.20	30.46%	(877.20)	-30.46%
1980-1982	4833.29	0.00	0.00%	1,467.88	30.37%	(1,467.88)	-30.37%
1981-1983	3699.12	0.00	0.00%	840.37	22.72%	(840.37)	-22.72%
1982-1984	2885.78	0.00	0.00%	609.90	21.13%	(609.90)	-21.13%
1983-1985	2677.93	1,096.13	40.93%	733.70	27.40%	362.43	13.53%
1984-1986	3684.34	475.67	12.91%	1,514.80	41.11%	(1,039.13)	-28.20%
1985-1987	3947.03	475.67	12.05%	1,598.13	40.49%	(1,122.46)	-28.44%
1986-1988	2354.99	(620.46)	-26.35%	864.43	36.71%	(1,484.89)	-63.05%
1987-1989	2966.86	1.00	0.03%	531.61	17.92%	(530.61)	-17.88%
1988-1990	2848.28	1.00	0.04%	971.75	34.12%	(970.75)	-34.08%
1989-1991	5898.07	1.00	0.02%	3,493.06	59.22%	(3,492.06)	-59.21%
1990-1992	8236.50	0.00	0.00%	5,596.81	67.95%	(5,596.81)	-67.95%
1991-1993	10830.32	0.00	0.00%	6,707.06	61.93%	(6,707.06)	-61.93%
1992-1994	12762.28	0.00	0.00%	6,397.55	50.13%	(6,397.55)	-50.13%
1993-1995	9053.10	4,904.42	54.17%	4,580.07	50.59%	324.35	3.58%
1994-1996	8809.26	4,904.42	55.67%	7,686.20	87.25%	(2,781.78)	-31.58%
1995-1997	9206.15	5,754.42	62.51%	5,731.40	62.26%	23.02	0.25%
1996-1998	9109.25	850.00	9.33%	5,596.85	61.44%	(4,746.85)	-52.11%
1997-1999	6440.96	850.00	13.20%	5,143.94	79.86%	(4,293.94)	-66.67%
1998-2000	4503.16	1.00	0.02%	7,106.05	157.80%	(7,105.05)	-157.78%
1999-2001	5,139.03	1.00	0.02%	9,102.14	177.12%	(9,101.14)	-177.10%
1968-2001	70,213.84	11,971.49	17.05%	31,777.98	45.26%	(19,806.49)	-28.21%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	50
Avg Ret Age	38.0
Years to ASL	12
Inflation Factor At 2.75% to ASL	1.38

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	21.91%
1987-2001	15-Year Trend	27.19%
1992-2001	10-Year Trend	17.45%
1997-2001	5-Year Trend	-23.27%

Adjusted Salvage & C/O/R			**-23.27%**	**62.67%**	**-85.94%**
1985 Total	14,456.58	6,271.22			
LESS:					
Crookston	12,407.54	5,175.09			
Net Activity	2,049.04	1,096.13			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 376 - Mains

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	200,220.26	16,598.28	8.29%	26,859.47	13.41%	(10,261.19)	-5.12%
1969	194,137.09	15,939.46	8.21%	43,168.49	22.24%	(27,229.03)	-14.03%
1970	267,046.03	23,230.21	8.70%	46,950.89	17.58%	(23,720.68)	-8.88%
1971	177,113.50	13,833.58	7.81%	56,809.25	32.08%	(42,975.67)	-24.26%
1972	157,195.80	13,435.85	8.55%	42,912.41	27.30%	(29,476.56)	-18.75%
1973	135,609.90	13,644.75	10.06%	27,848.00	20.54%	(14,203.25)	-10.47%
1974	79,682.47	4,158.86	5.22%	33,340.09	41.84%	(29,181.23)	-36.62%
1975	127,632.18	7,857.70	6.16%	43,072.35	33.75%	(35,214.65)	-27.59%
1976	195,879.62	9,760.39	4.98%	58,379.94	29.80%	(48,619.55)	-24.82%
1977	84,326.99	(3,773.39)	-4.47%	25,097.78	29.76%	(28,871.17)	-34.24%
1978	116,364.42	10,832.09	9.31%	46,758.20	40.18%	(35,926.11)	-30.87%
1979	123,150.94	11,190.96	9.09%	36,244.68	29.43%	(25,053.72)	-20.34%
1980	88,516.03	3,479.59	3.93%	38,660.28	43.68%	(35,180.69)	-39.74%
1981	152,498.86	6,295.38	4.13%	46,691.72	30.62%	(40,396.34)	-26.49%
1982	127,572.66	(2,610.34)	-2.05%	56,734.00	44.47%	(59,344.34)	-46.52%
1983	161,051.86	(581.14)	-0.36%	104,094.70	64.63%	(104,675.84)	-65.00%
1984	185,619.78	(504.59)	-0.27%	90,504.85	48.76%	(91,009.44)	-49.03%
1985	142,490.14	(6,867.12)	-4.82%	94,130.78	66.06%	(100,997.90)	-70.88%
1986	164,397.14	(401.47)	-0.24%	51,009.31	31.03%	(51,410.78)	-31.27%
1987	201,062.80	(231.86)	-0.12%	90,443.45	44.98%	(90,675.31)	-45.10%
1988	281,758.55	(4,416.44)	-1.57%	101,619.66	36.07%	(106,036.10)	-37.63%
1989	149,536.04	317.65	0.21%	69,598.16	46.54%	(69,280.51)	-46.33%
1990	92,157.64	(2,915.53)	-3.16%	35,838.46	38.89%	(38,753.99)	-42.05%
1991	208,283.95	3,390.22	1.63%	72,574.40	34.84%	(69,184.18)	-33.22%
1992	261,776.43	(2,741.03)	-1.05%	81,630.92	31.18%	(84,371.95)	-32.23%
1993	129,595.28	(3,971.17)	-3.06%	60,124.58	46.39%	(64,095.75)	-49.46%
1994	362,204.01	(340.60)	-0.09%	96,506.29	26.64%	(96,846.89)	-26.74%
1995	81,561.25	0.10	0.00%	22,341.68	27.39%	(22,341.58)	-27.39%
1996	312,810.33	767.42	0.25%	83,391.55	26.66%	(82,624.13)	-26.41%
1997	182,351.81	56,675.22	31.08%	0.00	0.00%	56,675.22	31.08%
1998	196,796.74	805.67	0.41%	76,362.06	38.80%	(75,556.39)	-38.39%
1999	186,253.29	0.00	0.00%	82,439.31	44.26%	(82,439.31)	-44.26%
2000	158,497.94	0.00	0.00%	61,044.27	38.51%	(61,044.27)	-38.51%
2001	171,123.71	0.00	0.00%	74,109.60	43.31%	(74,109.60)	-43.31%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 376 - Mains

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	661,403.38	55,767.95	8.43%	116,978.85	17.69%	(61,210.90)	-9.25%
1969-1971	638,296.62	53,003.25	8.30%	146,928.63	23.02%	(93,925.38)	-14.72%
1970-1972	601,355.33	50,499.64	8.40%	146,672.55	24.39%	(96,172.91)	-15.99%
1971-1973	469,919.20	40,914.18	8.71%	127,569.66	27.15%	(86,655.48)	-18.44%
1972-1974	372,488.17	31,239.46	8.39%	104,100.50	27.95%	(72,861.04)	-19.56%
1973-1975	342,924.55	25,661.31	7.48%	104,260.44	30.40%	(78,599.13)	-22.92%
1974-1976	403,194.27	21,776.95	5.40%	134,792.38	33.43%	(113,015.43)	-28.03%
1975-1977	407,838.79	13,844.70	3.39%	126,550.07	31.03%	(112,705.37)	-27.63%
1976-1978	396,571.03	16,819.09	4.24%	130,235.92	32.84%	(113,416.83)	-28.60%
1977-1979	323,842.35	18,249.66	5.64%	108,100.66	33.38%	(89,851.00)	-27.75%
1978-1980	328,031.39	25,502.64	7.77%	121,663.16	37.09%	(96,160.52)	-29.31%
1979-1981	364,165.83	20,965.93	5.76%	121,596.68	33.39%	(100,630.75)	-27.63%
1980-1982	368,587.55	7,164.63	1.94%	142,086.00	38.55%	(134,921.37)	-36.60%
1981-1983	441,123.38	3,103.90	0.70%	207,520.42	47.04%	(204,416.52)	-46.34%
1982-1984	474,244.30	(3,696.07)	-0.78%	251,333.55	53.00%	(255,029.62)	-53.78%
1983-1985	489,161.78	(7,952.85)	-1.63%	288,730.33	59.03%	(296,683.18)	-60.65%
1984-1986	492,507.06	(7,773.18)	-1.58%	235,644.94	47.85%	(243,418.12)	-49.42%
1985-1987	507,950.08	(7,500.45)	-1.48%	235,583.54	46.38%	(243,083.99)	-47.86%
1986-1988	647,218.49	(5,049.77)	-0.78%	243,072.42	37.56%	(248,122.19)	-38.34%
1987-1989	632,357.39	(4,330.65)	-0.68%	261,661.27	41.38%	(265,991.92)	-42.06%
1988-1990	523,452.23	(7,014.32)	-1.34%	207,056.28	39.56%	(214,070.60)	-40.90%
1989-1991	449,977.63	792.34	0.18%	178,011.02	39.56%	(177,218.68)	-39.38%
1990-1992	562,218.02	(2,266.34)	-0.40%	190,043.78	33.80%	(192,310.12)	-34.21%
1991-1993	599,655.66	(3,321.98)	-0.55%	214,329.90	35.74%	(217,651.88)	-36.30%
1992-1994	753,575.72	(7,052.80)	-0.94%	238,261.79	31.62%	(245,314.59)	-32.55%
1993-1995	573,360.54	(4,311.67)	-0.75%	178,972.55	31.21%	(183,284.22)	-31.97%
1994-1996	756,575.59	426.92	0.06%	202,239.52	26.73%	(201,812.60)	-26.67%
1995-1997	576,723.39	57,442.74	9.96%	105,733.23	18.33%	(48,290.49)	-8.37%
1996-1998	691,958.88	58,248.31	8.42%	159,753.61	23.09%	(101,505.30)	-14.67%
1997-1999	565,401.84	57,480.89	10.17%	158,801.37	28.09%	(101,320.48)	-17.92%
1998-2000	541,547.97	805.67	0.15%	219,845.64	40.60%	(219,039.97)	-40.45%
1999-2001	515,874.94	0.00	0.00%	217,593.18	42.18%	(217,593.18)	-42.18%
1968-2001	5,856,275.44	182,858.70	3.12%	1,977,291.58	33.76%	(1,794,432.88)	-30.64%

Trend Analysis (End Year) 2001

*** Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	45
Avg Ret Age	25.0
Years to ASL	20
Inflation Factor At 2.75% to ASL	1.72

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	4.11%
1987-2001	15-Year Trend	5.45%
1992-2001	10-Year Trend	5.99%
1997-2001	5-Year Trend	-2.72%

Adjusted Salvage & C/O/R			**-2.72%**		**58.09%**		**-60.81%**

1985 Total	1,003,495.26	537,399.44	
LESS:			
Crookston	861,005.12	544,266.56	
Net Activity	142,490.14	(6,867.12)	

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 378 - Measuring & Regulating Station Equipment - General

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	6,165.67	245.53	3.98%	384.57	6.24%	(139.04)	-2.26%
1969	5,072.04	681.64	13.44%	926.88	18.27%	(245.24)	-4.84%
1970	2,400.38	299.68	12.48%	794.84	33.11%	(495.16)	-20.63%
1971	5,953.07	1,423.90	23.92%	1,335.56	22.43%	88.34	1.48%
1972	8,537.76	1,548.78	18.14%	996.65	11.67%	552.13	6.47%
1973	4,721.42	136.76	2.90%	(230.17)	-4.88%	366.93	7.77%
1974	7,786.40	934.98	12.01%	1,803.46	23.16%	(868.48)	-11.15%
1975	5,798.87	1,131.96	19.52%	1,811.88	31.25%	(679.92)	-11.73%
1976	9,370.41	1,641.73	17.52%	850.97	9.08%	790.76	8.44%
1977	9,211.09	2,097.50	22.77%	1,860.19	20.20%	237.31	2.58%
1978	7,880.15	1,956.75	24.83%	1,742.60	22.11%	214.15	2.72%
1979	4,423.45	694.41	15.70%	2,237.76	50.59%	(1,543.35)	-34.89%
1980	11,750.95	11,103.62	94.49%	2,645.90	22.52%	8,457.72	71.97%
1981	2,893.54	856.15	29.59%	386.70	13.36%	469.45	16.22%
1982	3,107.26	1,493.08	48.05%	3,757.57	120.93%	(2,264.49)	-72.88%
1983	15,302.51	4,641.93	30.33%	3,904.22	25.51%	737.71	4.82%
1984	7,769.09	5,792.53	74.56%	945.55	12.17%	4,846.98	62.39%
1985	11,166.83	8,110.43	72.63%	1,598.99	14.32%	6,511.44	58.31%
1986	6,028.86	3,133.32	51.97%	1,178.98	19.56%	1,954.34	32.42%
1987	4,864.25	1,168.80	24.03%	608.41	12.51%	560.39	11.52%
1988	17,936.07	8,021.93	44.73%	3,187.18	17.77%	4,834.75	26.96%
1989	11,708.76	2,017.11	17.23%	2,832.97	24.20%	(815.86)	-6.97%
1990	3,904.28	1,256.18	32.17%	977.17	25.03%	279.01	7.15%
1991	5,145.64	868.70	16.88%	1,939.74	37.70%	(1,071.04)	-20.81%
1992	14,934.74	1,870.26	12.52%	4,119.48	27.58%	(2,249.22)	-15.06%
1993	5,076.89	671.04	13.22%	65.67	1.29%	605.37	11.92%
1994	53,564.31	6,804.16	12.70%	4,545.24	8.49%	2,258.92	4.22%
1995	3,767.18	4,785.35	127.03%	4,926.89	130.78%	(141.54)	-3.76%
1996	23,029.73	4,351.90	18.90%	10,141.37	44.04%	(5,789.47)	-25.14%
1997	16,951.86	712.79	4.20%	8,056.88	47.53%	(7,344.09)	-43.32%
1998	17,131.15	1,482.18	8.65%	8,754.03	51.10%	(7,271.85)	-42.45%
1999	3,292.16	0.00	0.00%	749.36	22.76%	(749.36)	-22.76%
2000	11,156.50	962.68	8.63%	6,839.22	61.30%	(5,876.54)	-52.67%
2001	8,696.02	2,153.63	24.77%	6,139.17	70.60%	(3,985.54)	-45.83%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 378 - Measuring & Regulating Station Equipment - General

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	13,638.09	1,226.85	9.00%	2,106.29	15.44%	(879.44)	-6.45%
1969-1971	13,425.49	2,405.22	17.92%	3,057.28	22.77%	(652.06)	-4.86%
1970-1972	16,891.21	3,272.36	19.37%	3,127.05	18.51%	145.31	0.86%
1971-1973	19,212.25	3,109.44	16.18%	2,102.04	10.94%	1,007.40	5.24%
1972-1974	21,045.58	2,620.52	12.45%	2,569.94	12.21%	50.58	0.24%
1973-1975	18,306.69	2,203.70	12.04%	3,385.17	18.49%	(1,181.47)	-6.45%
1974-1976	22,955.68	3,708.67	16.16%	4,466.31	19.46%	(757.64)	-3.30%
1975-1977	24,380.37	4,871.19	19.98%	4,523.04	18.55%	348.15	1.43%
1976-1978	26,461.65	5,695.98	21.53%	4,453.76	16.83%	1,242.22	4.69%
1977-1979	21,514.69	4,748.66	22.07%	5,840.55	27.15%	(1,091.89)	-5.08%
1978-1980	24,054.55	13,754.78	57.18%	6,626.26	27.55%	7,128.52	29.63%
1979-1981	19,067.94	12,654.18	66.36%	5,270.36	27.64%	7,383.82	38.72%
1980-1982	17,751.75	13,452.85	75.78%	6,790.17	38.25%	6,662.68	37.53%
1981-1983	21,303.31	6,991.16	32.82%	8,048.49	37.78%	(1,057.33)	-4.96%
1982-1984	26,178.86	11,927.54	45.56%	8,607.34	32.88%	3,320.20	12.68%
1983-1985	34,238.43	18,544.89	54.16%	6,448.76	18.83%	12,096.13	35.33%
1984-1986	24,964.78	17,036.28	68.24%	3,723.52	14.92%	13,312.76	53.33%
1985-1987	22,059.94	12,412.55	56.27%	3,386.38	15.35%	9,026.17	40.92%
1986-1988	28,829.18	12,324.05	42.75%	4,974.57	17.26%	7,349.48	25.49%
1987-1989	34,509.08	11,207.84	32.48%	6,628.56	19.21%	4,579.28	13.27%
1988-1990	33,549.11	11,295.22	33.67%	6,997.32	20.86%	4,297.90	12.81%
1989-1991	20,758.68	4,141.99	19.95%	5,749.88	27.70%	(1,607.89)	-7.75%
1990-1992	23,984.66	3,995.14	16.66%	7,036.39	29.34%	(3,041.25)	-12.68%
1991-1993	25,157.27	3,410.00	13.55%	6,124.89	24.35%	(2,714.89)	-10.79%
1992-1994	73,575.94	9,345.46	12.70%	8,730.39	11.87%	615.07	0.84%
1993-1995	62,408.38	12,260.55	19.65%	9,537.80	15.28%	2,722.75	4.36%
1994-1996	80,361.22	15,941.41	19.84%	19,613.50	24.41%	(3,672.09)	-4.57%
1995-1997	43,748.77	9,850.04	22.52%	23,125.14	52.86%	(13,275.10)	-30.34%
1996-1998	57,112.74	6,546.87	11.46%	26,952.28	47.19%	(20,405.41)	-35.73%
1997-1999	37,375.17	2,194.97	5.87%	17,560.27	46.98%	(15,365.30)	-41.11%
1998-2000	31,579.81	2,444.86	7.74%	16,342.61	51.75%	(13,897.75)	-44.01%
1999-2001	23,144.68	3,116.31	13.46%	13,727.75	59.31%	(10,611.44)	-45.85%
1968-2001	336,499.29	85,051.39	25.28%	92,815.88	27.58%	(7,764.49)	-2.31%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	-0.66%
1987-2001	15-Year Trend	1.58%
1992-2001	10-Year Trend	10.16%
1997-2001	5-Year Trend	5.66%

Adjusted Salvage & C/O/R			**5.66%**	**44.70%**	**-39.04%**
1985 Total	26,272.02	13,065.04			
LESS:					
Crookston	15,105.19	4,954.61			
Net Activity	11,166.83	8,110.43			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 379 - Measuring & Regulating Station Equipment - City Gate

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	18,414.18	5,785.41	31.42%	1,569.21	8.52%	4,216.20	22.90%
1969	16,569.97	4,369.23	26.37%	1,184.86	7.15%	3,184.37	19.22%
1970	13,735.04	3,662.00	26.66%	1,070.13	7.79%	2,591.87	18.87%
1971	8,371.34	2,075.36	24.79%	1,671.45	19.97%	403.91	4.82%
1972	30,257.72	6,523.51	21.56%	1,473.77	4.87%	5,049.74	16.69%
1973	5,526.84	2,274.92	41.16%	1,090.31	19.73%	1,184.61	21.43%
1974	6,833.15	879.07	12.86%	609.12	8.91%	269.95	3.95%
1975	3,276.17	851.21	25.98%	824.83	25.18%	26.38	0.81%
1976	5,133.75	2,898.47	56.46%	954.06	18.58%	1,944.41	37.88%
1977	1,235.92	386.35	31.26%	435.84	35.26%	(49.49)	-4.00%
1978	8,311.82	2,644.04	31.81%	2,548.00	30.66%	96.04	1.16%
1979	2,493.74	874.25	35.06%	226.52	9.08%	647.73	25.97%
1980	4,989.43	2,200.37	44.10%	308.90	6.19%	1,891.47	37.91%
1981	19,759.99	11,981.07	60.63%	4,298.58	21.75%	7,682.49	38.88%
1982	15,342.56	7,067.64	46.07%	1,787.32	11.65%	5,280.32	34.42%
1983	5,370.15	7,646.09	142.38%	896.74	16.70%	6,749.35	125.68%
1984	11,813.59	4,661.41	39.46%	1,805.26	15.28%	2,856.15	24.18%
1985	20,078.95	4,189.55	20.87%	0.00	0.00%	4,189.55	20.87%
1986			0.00%		0.00%	0.00	0.00%
1987	240.01	0.00	0.00%	56.84	23.68%	(56.84)	-23.68%
1988	3,178.76	0.00	0.00%		0.00%	0.00	0.00%
1989	565.28	109.81	19.43%	41.97	7.42%	67.84	12.00%
1990			0.00%		0.00%	0.00	0.00%
1991	6,702.82	0.00	0.00%		0.00%	0.00	0.00%
1992	225.00	0.00	0.00%	23.32	10.36%	(23.32)	-10.36%
1993		0.00	0.00%		0.00%	0.00	0.00%
1994	24,000.34	6,121.69	25.51%	248.40	1.03%	5,873.29	24.47%
1995	1,429.24	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	375.00	0.00%	0.00	0.00%	375.00	0.00%
1997	19,117.83	3,723.12	19.47%	845.73	4.42%	2,877.39	15.05%
1998	2,593.97	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	1,744.33	0.00	0.00%	279.93	16.05%	(279.93)	-16.05%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 379 - Measuring & Regulating Station Equipment - City Gate

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	48,719.19	13,816.64	28.36%	3,824.20	7.85%	9,992.44	20.51%
1969-1971	38,676.35	10,106.59	26.13%	3,926.44	10.15%	6,180.15	15.98%
1970-1972	52,364.10	12,260.87	23.41%	4,215.35	8.05%	8,045.52	15.36%
1971-1973	44,155.90	10,873.79	24.63%	4,235.53	9.59%	6,638.26	15.03%
1972-1974	42,617.71	9,677.50	22.71%	3,173.20	7.45%	6,504.30	15.26%
1973-1975	15,636.16	4,005.20	25.61%	2,524.26	16.14%	1,480.94	9.47%
1974-1976	15,243.07	4,628.75	30.37%	2,388.01	15.67%	2,240.74	14.70%
1975-1977	9,645.84	4,136.03	42.88%	2,214.73	22.96%	1,921.30	19.92%
1976-1978	14,681.49	5,928.86	40.38%	3,937.90	26.82%	1,990.96	13.56%
1977-1979	12,041.48	3,904.64	32.43%	3,210.36	26.66%	694.28	5.77%
1978-1980	15,794.99	5,718.66	36.21%	3,083.42	19.52%	2,635.24	16.68%
1979-1981	27,243.16	15,055.69	55.26%	4,834.00	17.74%	10,221.69	37.52%
1980-1982	40,091.98	21,249.08	53.00%	6,394.80	15.95%	14,854.28	37.05%
1981-1983	40,472.70	26,694.80	65.96%	6,982.64	17.25%	19,712.16	48.70%
1982-1984	32,526.30	19,375.14	59.57%	4,489.32	13.80%	14,885.82	45.77%
1983-1985	37,262.69	16,497.05	44.27%	2,702.00	7.25%	13,795.05	37.02%
1984-1986	31,892.54	8,850.96	27.75%	1,805.26	5.66%	7,045.70	22.09%
1985-1987	20,318.96	4,189.55	20.62%	56.84	0.28%	4,132.71	20.34%
1986-1988	3,418.77	0.00	0.00%	56.84	1.66%	(56.84)	-1.66%
1987-1989	3,984.05	109.81	2.76%	98.81	2.48%	11.00	0.28%
1988-1990	3,744.04	109.81	2.93%	41.97	1.12%	67.84	1.81%
1989-1991	7,268.10	109.81	1.51%	41.97	0.58%	67.84	0.93%
1990-1992	6,927.82	0.00	0.00%	23.32	0.34%	(23.32)	-0.34%
1991-1993	6,927.82	0.00	0.00%	23.32	0.34%	(23.32)	-0.34%
1992-1994	24,225.34	6,121.69	25.27%	271.72	1.12%	5,849.97	24.15%
1993-1995	25,429.58	6,121.69	24.07%	248.40	0.98%	5,873.29	23.10%
1994-1996	25,429.58	6,496.69	25.55%	248.40	0.98%	6,248.29	24.57%
1995-1997	20,547.07	4,098.12	19.95%	845.73	4.12%	3,252.39	15.83%
1996-1998	21,711.80	4,098.12	18.88%	845.73	3.90%	3,252.39	14.98%
1997-1999	23,456.13	3,723.12	15.87%	1,125.66	4.80%	2,597.46	11.07%
1998-2000	4,338.30	0.00	0.00%	279.93	6.45%	(279.93)	-6.45%
1999-2001	1,744.33	0.00	0.00%	279.93	16.05%	(279.93)	-16.05%
1968-2001	257,311.89	81,299.57	31.60%	24,251.09	9.42%	57,048.48	22.17%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	23.1
Years to ASL	16.9
Inflation Factor At 2.75% to ASL	1.58

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	-2.38%
1987-2001	15-Year Trend	13.79%
1992-2001	10-Year Trend	10.69%
1997-2001	5-Year Trend	-6.69%

Adjusted Salvage & C/O/R			**-6.69%**	**14.91%**	**-21.60%**
1985 Total	20,078.95	4,189.55			
LESS:					
Crookston	20,078.95	4,197.42			
Net Activity	0.00	(7.87)			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 380 - Services

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	58,055.53	3,059.40	5.27%	27,723.99	47.75%	(24,664.59)	-42.48%
1969	55,853.48	845.59	1.51%	26,200.12	46.91%	(25,354.53)	-45.39%
1970	78,879.56	530.18	0.67%	23,001.10	29.16%	(22,470.92)	-28.49%
1971	52,774.35	880.28	1.67%	35,729.03	67.70%	(34,848.75)	-66.03%
1972	79,522.93	697.12	0.88%	32,010.82	40.25%	(31,313.70)	-39.38%
1973	65,093.43	0.00	0.00%	48,919.91	75.15%	(48,919.91)	-75.15%
1974	64,653.14	596.73	0.92%	49,546.52	76.63%	(48,949.79)	-75.71%
1975	37,754.54	2,843.03	7.53%	50,159.99	132.86%	(47,316.96)	-125.33%
1976	68,213.75	0.00	0.00%	67,351.08	98.74%	(67,351.08)	-98.74%
1977	192,462.86	0.00	0.00%	53,563.74	27.83%	(53,563.74)	-27.83%
1978	(92,938.46)	0.00	0.00%	41,768.32	-44.94%	(41,768.32)	44.94%
1979	55,534.41	0.00	0.00%	79,598.42	143.33%	(79,598.42)	-143.33%
1980	61,494.60	0.00	0.00%	99,855.84	162.38%	(99,855.84)	-162.38%
1981	63,423.25	0.00	0.00%	102,204.63	161.15%	(102,204.63)	-161.15%
1982	84,858.56	0.00	0.00%	145,791.60	171.81%	(145,791.60)	-171.81%
1983	73,868.72	0.00	0.00%	134,537.21	182.13%	(134,537.21)	-182.13%
1984	95,311.04	0.00	0.00%	162,402.35	170.39%	(162,402.35)	-170.39%
1985	96,419.65	0.00	0.00%	218,282.65	226.39%	(218,282.65)	-226.39%
1986	82,204.03	0.00	0.00%	164,534.27	200.15%	(164,534.27)	-200.15%
1987	102,945.66	0.00	0.00%	178,763.94	173.65%	(178,763.94)	-173.65%
1988	130,255.01	0.00	0.00%	210,138.61	161.33%	(210,138.61)	-161.33%
1989	103,193.55	0.00	0.00%	194,613.23	188.59%	(194,613.23)	-188.59%
1990	87,093.75	0.00	0.00%	156,894.03	180.14%	(156,894.03)	-180.14%
1991	112,288.21	0.00	0.00%	154,878.88	137.93%	(154,878.88)	-137.93%
1992	152,087.98	0.00	0.00%	198,004.44	130.19%	(198,004.44)	-130.19%
1993	117,390.79	0.00	0.00%	156,754.23	133.53%	(156,754.23)	-133.53%
1994	213,594.75	0.00	0.00%	225,751.58	105.69%	(225,751.58)	-105.69%
1995	85,394.58	238.78	0.28%	132,997.10	155.74%	(132,758.32)	-155.46%
1996	190,887.20	489.25	0.26%	196,474.55	102.93%	(195,985.30)	-102.67%
1997	147,018.12	274.30	0.19%	167,867.03	114.18%	(167,592.73)	-113.99%
1998	156,868.35	165.57	0.11%	232,839.48	148.43%	(232,673.91)	-148.32%
1999	129,801.17	0.00	0.00%	205,972.55	158.68%	(205,972.55)	-158.68%
2000	134,394.03	0.00	0.00%	200,260.66	149.01%	(200,260.66)	-149.01%
2001	123,831.18	31.47	0.03%	203,228.57	164.12%	(203,197.10)	-164.09%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 380 - Services

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	192,788.57	4,435.17	2.30%	76,925.21	39.90%	(72,490.04)	-37.60%
1969-1971	187,507.39	2,256.05	1.20%	84,930.25	45.29%	(82,674.20)	-44.09%
1970-1972	211,176.84	2,107.58	1.00%	90,740.95	42.97%	(88,633.37)	-41.97%
1971-1973	197,390.71	1,577.40	0.80%	116,659.76	59.10%	(115,082.36)	-58.30%
1972-1974	209,269.50	1,293.85	0.62%	130,477.25	62.35%	(129,183.40)	-61.73%
1973-1975	167,501.11	3,439.76	2.05%	148,626.42	88.73%	(145,186.66)	-86.68%
1974-1976	170,621.43	3,439.76	2.02%	167,057.59	97.91%	(163,617.83)	-95.90%
1975-1977	298,431.15	2,843.03	0.95%	171,074.81	57.32%	(168,231.78)	-56.37%
1976-1978	167,738.15	0.00	0.00%	162,683.14	96.99%	(162,683.14)	-96.99%
1977-1979	155,058.81	0.00	0.00%	174,930.48	112.82%	(174,930.48)	-112.82%
1978-1980	24,090.55	0.00	0.00%	221,222.58	918.30%	(221,222.58)	-918.30%
1979-1981	180,452.26	0.00	0.00%	281,658.89	156.08%	(281,658.89)	-156.08%
1980-1982	209,776.41	0.00	0.00%	347,852.07	165.82%	(347,852.07)	-165.82%
1981-1983	222,150.53	0.00	0.00%	382,533.44	172.20%	(382,533.44)	-172.20%
1982-1984	254,038.32	0.00	0.00%	442,731.16	174.28%	(442,731.16)	-174.28%
1983-1985	265,599.41	0.00	0.00%	515,222.21	193.98%	(515,222.21)	-193.98%
1984-1986	273,934.72	0.00	0.00%	545,219.27	199.03%	(545,219.27)	-199.03%
1985-1987	281,569.34	0.00	0.00%	561,580.86	199.45%	(561,580.86)	-199.45%
1986-1988	315,404.70	0.00	0.00%	553,436.82	175.47%	(553,436.82)	-175.47%
1987-1989	336,394.22	0.00	0.00%	583,515.78	173.46%	(583,515.78)	-173.46%
1988-1990	320,542.31	0.00	0.00%	561,645.87	175.22%	(561,645.87)	-175.22%
1989-1991	302,575.51	0.00	0.00%	506,386.14	167.36%	(506,386.14)	-167.36%
1990-1992	351,469.94	0.00	0.00%	509,777.35	145.04%	(509,777.35)	-145.04%
1991-1993	381,766.98	0.00	0.00%	509,637.55	133.49%	(509,637.55)	-133.49%
1992-1994	483,073.52	0.00	0.00%	580,510.25	120.17%	(580,510.25)	-120.17%
1993-1995	416,380.12	238.78	0.06%	515,502.91	123.81%	(515,264.13)	-123.75%
1994-1996	489,876.53	728.03	0.15%	555,223.23	113.34%	(554,495.20)	-113.19%
1995-1997	423,299.90	1,002.33	0.24%	497,338.68	117.49%	(496,336.35)	-117.25%
1996-1998	494,773.67	929.12	0.19%	597,181.06	120.70%	(596,251.94)	-120.51%
1997-1999	433,687.64	439.87	0.10%	606,679.06	139.89%	(606,239.19)	-139.79%
1998-2000	421,063.55	165.57	0.04%	639,072.69	151.78%	(638,907.12)	-151.74%
1999-2001	388,026.38	31.47	0.01%	609,461.78	157.07%	(609,430.31)	-157.06%
1968-2001	3,260,483.70	10,651.70	0.33%	4,378,620.47	134.29%	(4,367,968.77)	-133.97%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	20.0
Years to ASL	20.0
Inflation Factor At 2.75% to ASL	1.72

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.11%
1987-2001	15-Year Trend	0.13%
1992-2001	10-Year Trend	0.12%
1997-2001	5-Year Trend	-0.07%

Adjusted Salvage & C/O/R			**-0.07%**		**231.04%**		**-231.11%**
1985 Total	368,325.74	160,331.72					
LESS:							
Crookston	271,906.09	173,296.49					
Net Activity	96,419.65	(12,964.77)					

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 381 - Meters

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	89,621.05	20,853.15	23.27%	100.61	0.11%	20,752.54	23.16%
1969	88,141.67	21,175.77	24.02%	4.76	0.01%	21,171.01	24.02%
1970	84,232.62	22,634.02	26.87%	0.00	0.00%	22,634.02	26.87%
1971	113,603.29	45,459.80	40.02%	0.00	0.00%	45,459.80	40.02%
1972	104,367.42	28,705.75	27.50%	5.00	0.00%	28,700.75	27.50%
1973	103,144.67	33,345.95	32.33%	0.00	0.00%	33,345.95	32.33%
1974	102,736.09	52,118.35	50.73%	0.00	0.00%	52,118.35	50.73%
1975	165,635.60	63,047.92	38.06%	0.00	0.00%	63,047.92	38.06%
1976	135,627.82	59,618.84	43.96%	0.00	0.00%	59,618.84	43.96%
1977	71,937.22	25,174.11	34.99%	0.00	0.00%	25,174.11	34.99%
1978	131,277.92	52,316.96	39.85%	0.00	0.00%	52,316.96	39.85%
1979	148,233.80	64,025.07	43.19%	(43.43)	-0.03%	64,068.50	43.22%
1980	305,397.80	208,883.27	68.40%	77.59	0.03%	208,805.68	68.37%
1981	126,975.53	50,478.48	39.75%	0.00	0.00%	50,478.48	39.75%
1982	154,079.01	35,126.16	22.80%	(167.28)	-0.11%	35,293.44	22.91%
1983	162,477.00	27,158.04	16.72%	(22.73)	-0.01%	27,180.77	16.73%
1984	271,430.65	51,182.92	18.86%	0.00	0.00%	51,182.92	18.86%
1985	184,437.92	22,237.84	12.06%	0.00	0.00%	22,237.84	12.06%
1986	120,997.42	22,771.82	18.82%	0.00	0.00%	22,771.82	18.82%
1987	113,329.32	19,829.78	17.50%	0.00	0.00%	19,829.78	17.50%
1988	133,122.11	20,425.53	15.34%	0.00	0.00%	20,425.53	15.34%
1989	118,174.74	16,855.60	14.26%	0.00	0.00%	16,855.60	14.26%
1990	74,744.83	6,283.18	8.41%	0.00	0.00%	6,283.18	8.41%
1991	80,430.53	2,892.22	3.60%	0.00	0.00%	2,892.22	3.60%
1992	106,428.89	2,245.90	2.11%	0.00	0.00%	2,245.90	2.11%
1993	86,460.76	4,464.18	5.16%	0.00	0.00%	4,464.18	5.16%
1994	140,444.26	4,954.94	3.53%	28.34	0.02%	4,926.60	3.51%
1995	265,413.57	140.83	0.05%	0.00	0.00%	140.83	0.05%
1996	143,875.77	8,202.93	5.70%	0.00	0.00%	8,202.93	5.70%
1997	163,997.79	3,569.20	2.18%	0.00	0.00%	3,569.20	2.18%
1998	167,984.94	395.20	0.24%	0.00	0.00%	395.20	0.24%
1999	105,617.04	1,111.77	1.05%	0.00	0.00%	1,111.77	1.05%
2000	82,561.94	12,514.29	15.16%	0.00	0.00%	12,514.29	15.16%
2001	417,486.88	3,201.41	0.77%	92,372.21	22.13%	(89,170.80)	-21.36%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 381 - Meters

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	261,995.34	64,662.94	24.68%	105.37	0.04%	64,557.57	24.64%
1969-1971	285,977.58	89,269.59	31.22%	4.76	0.00%	89,264.83	31.21%
1970-1972	302,203.33	96,799.57	32.03%	5.00	0.00%	96,794.57	32.03%
1971-1973	321,115.38	107,511.50	33.48%	5.00	0.00%	107,506.50	33.48%
1972-1974	310,248.18	114,170.05	36.80%	5.00	0.00%	114,165.05	36.80%
1973-1975	371,516.36	148,512.22	39.97%	0.00	0.00%	148,512.22	39.97%
1974-1976	403,999.51	174,785.11	43.26%	0.00	0.00%	174,785.11	43.26%
1975-1977	373,200.64	147,840.87	39.61%	0.00	0.00%	147,840.87	39.61%
1976-1978	338,842.96	137,109.91	40.46%	0.00	0.00%	137,109.91	40.46%
1977-1979	351,448.94	141,516.14	40.27%	(43.43)	-0.01%	141,559.57	40.28%
1978-1980	584,909.52	325,225.30	55.60%	34.16	0.01%	325,191.14	55.60%
1979-1981	580,607.13	323,386.82	55.70%	34.16	0.01%	323,352.66	55.69%
1980-1982	586,452.34	294,487.91	50.22%	(89.69)	-0.02%	294,577.60	50.23%
1981-1983	443,531.54	112,762.68	25.42%	(190.01)	-0.04%	112,952.69	25.47%
1982-1984	587,986.66	113,467.12	19.30%	(190.01)	-0.03%	113,657.13	19.33%
1983-1985	618,345.57	100,578.80	16.27%	(22.73)	0.00%	100,601.53	16.27%
1984-1986	576,865.99	96,192.58	16.68%	0.00	0.00%	96,192.58	16.68%
1985-1987	418,764.66	64,839.44	15.48%	0.00	0.00%	64,839.44	15.48%
1986-1988	367,448.85	63,027.13	17.15%	0.00	0.00%	63,027.13	17.15%
1987-1989	364,626.17	57,110.91	15.66%	0.00	0.00%	57,110.91	15.66%
1988-1990	326,041.68	43,564.31	13.36%	0.00	0.00%	43,564.31	13.36%
1989-1991	273,350.10	26,031.00	9.52%	0.00	0.00%	26,031.00	9.52%
1990-1992	261,604.25	11,421.30	4.37%	0.00	0.00%	11,421.30	4.37%
1991-1993	273,320.18	9,602.30	3.51%	0.00	0.00%	9,602.30	3.51%
1992-1994	333,333.91	11,665.02	3.50%	28.34	0.01%	11,636.68	3.49%
1993-1995	492,318.59	9,559.95	1.94%	28.34	0.01%	9,531.61	1.94%
1994-1996	549,733.60	13,298.70	2.42%	28.34	0.01%	13,270.36	2.41%
1995-1997	573,287.13	11,912.96	2.08%	0.00	0.00%	11,912.96	2.08%
1996-1998	475,858.50	12,167.33	2.56%	0.00	0.00%	12,167.33	2.56%
1997-1999	437,599.77	5,076.17	1.16%	0.00	0.00%	5,076.17	1.16%
1998-2000	356,163.92	14,021.26	3.94%	0.00	0.00%	14,021.26	3.94%
1999-2001	605,665.86	16,827.47	2.78%	92,372.21	15.25%	(75,544.74)	-12.47%
1968-2001	4,864,427.87	1,013,401.18	20.83%	92,355.07	1.90%	921,046.11	18.93%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	35
Avg Ret Age	26.6
Years to ASL	8.4
Inflation Factor At 2.75% to ASL	1.26

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	-5.98%
1987-2001	15-Year Trend	-2.28%
1992-2001	10-Year Trend	2.11%
1997-2001	5-Year Trend	3.34%

Adjusted Salvage & C/O/R			**3.34%**	**2.38%**	**0.95%**
1985 Total	378,528.40	167,070.09			
LESS:					
Crookston	194,090.48	144,832.25			
Net Activity	184,437.92	22,237.84			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 383 - Service Regulators

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	10,480.51	1,798.17	17.16%	0.00	0.00%	1,798.17	17.16%
1969	15,625.37	1,952.40	12.50%	0.00	0.00%	1,952.40	12.50%
1970	7,948.48	2,721.43	34.24%	0.00	0.00%	2,721.43	34.24%
1971	13,967.47	1,582.76	11.33%	0.00	0.00%	1,582.76	11.33%
1972	19,005.32	5,947.81	31.30%	51.06	0.27%	5,896.75	31.03%
1973	19,824.36	7,979.91	40.25%	0.00	0.00%	7,979.91	40.25%
1974	16,485.63	2,951.77	17.91%	0.00	0.00%	2,951.77	17.91%
1975	18,650.29	13,618.89	73.02%	0.00	0.00%	13,618.89	73.02%
1976	22,731.51	7,934.37	34.90%	131.40	0.58%	7,802.97	34.33%
1977	11,250.78	3,332.87	29.62%	78.30	0.70%	3,254.57	28.93%
1978	13,280.23	3,807.19	28.67%	9.58	0.07%	3,797.61	28.60%
1979	16,135.49	6,063.67	37.58%	0.00	0.00%	6,063.67	37.58%
1980	17,812.86	5,072.17	28.47%	76.60	0.43%	4,995.57	28.04%
1981	18,881.47	2,694.22	14.27%	26.37	0.14%	2,667.85	14.13%
1982	31,214.62	3,046.01	9.76%	0.00	0.00%	3,046.01	9.76%
1983	34,299.20	4,938.52	14.40%	0.00	0.00%	4,938.52	14.40%
1984	54,363.07	4,955.13	9.11%	0.00	0.00%	4,955.13	9.11%
1985	31,637.01	7,049.21	22.28%	96.12	0.30%	6,953.09	21.98%
1986	26,481.25	6,050.68	22.85%	0.00	0.00%	6,050.68	22.85%
1987	28,723.49	3,727.71	12.98%	836.11	2.91%	2,891.60	10.07%
1988	37,400.09	4,520.88	12.09%	668.31	1.79%	3,852.57	10.30%
1989	37,255.58	3,404.35	9.14%	0.00	0.00%	3,404.35	9.14%
1990	45,689.19	2,229.08	4.88%	0.00	0.00%	2,229.08	4.88%
1991	51,279.08	4,323.62	8.43%	173.62	0.34%	4,150.00	8.09%
1992	33,968.77	6,837.93	20.13%	0.00	0.00%	6,837.93	20.13%
1993	35,131.57	3,569.60	10.16%	0.00	0.00%	3,569.60	10.16%
1994	35,847.05	3,465.08	9.67%	0.00	0.00%	3,465.08	9.67%
1995	38,394.60	378.34	0.99%	0.00	0.00%	378.34	0.99%
1996	55,447.33	10,698.81	19.30%	737.81	1.33%	9,961.00	17.96%
1997	16,405.83	7,613.53	46.41%	0.00	0.00%	7,613.53	46.41%
1998	30,249.00	1,656.02	5.47%	0.00	0.00%	1,656.02	5.47%
1999	887.29	2,804.86	316.12%	0.00	0.00%	2,804.86	316.12%
2000	3,372.89	5,066.21	150.20%	72.07	2.14%	4,994.14	148.07%
2001	22,146.01	1,874.12	8.46%	0.00	0.00%	1,874.12	8.46%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 383 - Service Regulators

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	34,054.36	6,472.00	19.00%	0.00	0.00%	6,472.00	19.00%
1969-1971	37,541.32	6,256.59	16.67%	0.00	0.00%	6,256.59	16.67%
1970-1972	40,921.27	10,252.00	25.05%	51.06	0.12%	10,200.94	24.93%
1971-1973	52,797.15	15,510.48	29.38%	51.06	0.10%	15,459.42	29.28%
1972-1974	55,315.31	16,879.49	30.52%	51.06	0.09%	16,828.43	30.42%
1973-1975	54,960.28	24,550.57	44.67%	0.00	0.00%	24,550.57	44.67%
1974-1976	57,867.43	24,505.03	42.35%	131.40	0.23%	24,373.63	42.12%
1975-1977	52,632.58	24,886.13	47.28%	209.70	0.40%	24,676.43	46.88%
1976-1978	47,262.52	15,074.43	31.90%	219.28	0.46%	14,855.15	31.43%
1977-1979	40,666.50	13,203.73	32.47%	87.88	0.22%	13,115.85	32.25%
1978-1980	47,228.58	14,943.03	31.64%	86.18	0.18%	14,856.85	31.46%
1979-1981	52,829.82	13,830.06	26.18%	102.97	0.19%	13,727.09	25.98%
1980-1982	67,908.95	10,812.40	15.92%	102.97	0.15%	10,709.43	15.77%
1981-1983	84,395.29	10,678.75	12.65%	26.37	0.03%	10,652.38	12.62%
1982-1984	119,876.89	12,939.66	10.79%	0.00	0.00%	12,939.66	10.79%
1983-1985	120,299.28	16,942.86	14.08%	96.12	0.08%	16,846.74	14.00%
1984-1986	112,481.33	18,055.02	16.05%	96.12	0.09%	17,958.90	15.97%
1985-1987	86,841.75	16,827.60	19.38%	932.23	1.07%	15,895.37	18.30%
1986-1988	92,604.83	14,299.27	15.44%	1,504.42	1.62%	12,794.85	13.82%
1987-1989	103,379.16	11,652.94	11.27%	1,504.42	1.46%	10,148.52	9.82%
1988-1990	120,344.86	10,154.31	8.44%	668.31	0.56%	9,486.00	7.88%
1989-1991	134,223.85	9,957.05	7.42%	173.62	0.13%	9,783.43	7.29%
1990-1992	130,937.04	13,390.63	10.23%	173.62	0.13%	13,217.01	10.09%
1991-1993	120,379.42	14,731.15	12.24%	173.62	0.14%	14,557.53	12.09%
1992-1994	104,947.39	13,872.61	13.22%	0.00	0.00%	13,872.61	13.22%
1993-1995	109,373.22	7,413.02	6.78%	0.00	0.00%	7,413.02	6.78%
1994-1996	129,688.98	14,542.23	11.21%	737.81	0.57%	13,804.42	10.64%
1995-1997	110,247.76	18,690.68	16.95%	737.81	0.67%	17,952.87	16.28%
1996-1998	102,102.16	19,968.36	19.56%	737.81	0.72%	19,230.55	18.83%
1997-1999	47,542.12	12,074.41	25.40%	0.00	0.00%	12,074.41	25.40%
1998-2000	34,509.18	9,527.09	27.61%	72.07	0.21%	9,455.02	27.40%
1999-2001	26,406.19	9,745.19	36.90%	72.07	0.27%	9,673.12	36.63%
1968-2001	872,272.69	155,667.32	17.85%	2,957.35	0.34%	152,709.97	17.51%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	35
Avg Ret Age	26.8
Years to ASL	8.2
Inflation Factor At 2.75% to ASL	1.25

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	22.23%
1987-2001	15-Year Trend	25.73%
1992-2001	10-Year Trend	33.10%
1997-2001	5-Year Trend	39.67%

Adjusted Salvage & C/O/R			**39.67%**	**0.42%**	**39.25%**
1985 Total	89,106.49	32,504.55			
LESS:					
Crookston	57,469.48	25,455.34			
Net Activity	31,637.01	7,049.21			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 385 - Industrial Meas. & Reg. Station Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	613.45	-	0.00%	129.34	21.08%	(129.34)	-21.08%
1969	4,471.70	2,577.52	57.64%	179.48	4.01%	2,398.04	53.63%
1970	840.44	26.46	3.15%	0.00	0.00%	26.46	3.15%
1971	1,921.57	274.04	14.26%	59.46	3.09%	214.58	11.17%
1972	2,369.19	1,005.39	42.44%	156.56	6.61%	848.83	35.83%
1973	337.68	236.27	69.97%	12.88	3.81%	223.39	66.15%
1974	1,632.24	693.23	42.47%	7.72	0.47%	685.51	42.00%
1975	809.14	-	0.00%	31.14	3.85%	(31.14)	-3.85%
1976	2,695.45	3,193.08	118.46%	314.64	11.67%	2,878.44	106.79%
1977	628.56	460.91	73.33%	90.60	14.41%	370.31	58.91%
1978	246.13	13.63	5.54%	46.40	18.85%	(32.77)	-13.31%
1979	848.27	225.71	26.61%	358.00	42.20%	(132.29)	-15.60%
1980	2,986.62	1,982.76	66.39%	391.29	13.10%	1,591.47	53.29%
1981	4,852.47	1,027.50	21.17%	318.84	6.57%	708.66	14.60%
1982	2,491.09	1,293.36	51.92%	487.82	19.58%	805.54	32.34%
1983	937.60	1,109.18	118.30%	226.31	24.14%	882.87	94.16%
1984	1,819.48	897.15	49.31%	20.05	1.10%	877.10	48.21%
1985	3,181.13	-	0.00%	384.69	12.09%	(384.69)	-12.09%
1986	573.60	227.14	39.60%	0.00	0.00%	227.14	39.60%
1987	5,110.78	2,075.47	40.61%	653.90	12.79%	1,421.57	27.82%
1988	626.39	1,187.43	189.57%	118.00	18.84%	1,069.43	170.73%
1989	352.03	-	0.00%	0.00	0.00%	0.00	0.00%
1990	3,978.13	1,503.95	37.81%	48.64	1.22%	1,455.31	36.58%
1991	20,057.46	3,065.40	15.28%	1,824.81	9.10%	1,240.59	6.19%
1992	5,915.92	-	0.00%	0.00	0.00%	0.00	0.00%
1993		700.00	0.00%	0.00	0.00%	700.00	0.00%
1994	9,478.47	5,952.35	62.80%	612.40	6.46%	5,339.95	56.34%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	521.01	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	1,778.43	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	7,894.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	8,225.85	0.00	0.00%	1,350.95	16.42%	(1,350.95)	-16.42%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	375.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 385 - Industrial Meas. & Reg. Station Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	5,925.59	2,603.98	43.94%	308.82	5.21%	2,295.16	38.73%
1969-1971	7,233.71	2,878.02	39.79%	238.94	3.30%	2,639.08	36.48%
1970-1972	5,131.20	1,305.89	25.45%	216.02	4.21%	1,089.87	21.24%
1971-1973	4,628.44	1,515.70	32.75%	228.90	4.95%	1,286.80	27.80%
1972-1974	4,339.11	1,934.89	44.59%	177.16	4.08%	1,757.73	40.51%
1973-1975	2,779.06	929.50	33.45%	51.74	1.86%	877.76	31.58%
1974-1976	5,136.83	3,886.31	75.66%	353.50	6.88%	3,532.81	68.77%
1975-1977	4,133.15	3,653.99	88.41%	436.38	10.56%	3,217.61	77.85%
1976-1978	3,570.14	3,667.62	102.73%	451.64	12.65%	3,215.98	90.08%
1977-1979	1,722.96	700.25	40.64%	495.00	28.73%	205.25	11.91%
1978-1980	4,081.02	2,222.10	54.45%	795.69	19.50%	1,426.41	34.95%
1979-1981	8,687.36	3,235.97	37.25%	1,068.13	12.30%	2,167.84	24.95%
1980-1982	10,330.18	4,303.62	41.66%	1,197.95	11.60%	3,105.67	30.06%
1981-1983	8,281.16	3,430.04	41.42%	1,032.97	12.47%	2,397.07	28.95%
1982-1984	5,248.17	3,299.69	62.87%	734.18	13.99%	2,565.51	48.88%
1983-1985	5,938.21	2,006.33	33.79%	631.05	10.63%	1,375.28	23.16%
1984-1986	5,574.21	1,124.29	20.17%	404.74	7.26%	719.55	12.91%
1985-1987	8,865.51	2,302.61	25.97%	1,038.59	11.71%	1,264.02	14.26%
1986-1988	6,310.77	3,490.04	55.30%	771.90	12.23%	2,718.14	43.07%
1987-1989	6,089.20	3,262.90	53.59%	771.90	12.68%	2,491.00	40.91%
1988-1990	4,956.55	2,691.38	54.30%	166.64	3.36%	2,524.74	50.94%
1989-1991	24,387.62	4,569.35	18.74%	1,873.45	7.68%	2,695.90	11.05%
1990-1992	29,951.51	4,569.35	15.26%	1,873.45	6.25%	2,695.90	9.00%
1991-1993	25,973.38	3,765.40	14.50%	1,824.81	7.03%	1,940.59	7.47%
1992-1994	15,394.39	6,652.35	43.21%	612.40	3.98%	6,039.95	39.23%
1993-1995	9,478.47	6,652.35	70.18%	612.40	6.46%	6,039.95	63.72%
1994-1996	9,999.48	5,952.35	59.53%	612.40	6.12%	5,339.95	53.40%
1995-1997	2,299.44	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	10,193.85	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	17,898.69	0.00	0.00%	1,350.95	7.55%	(1,350.95)	-7.55%
1998-2000	16,120.26	0.00	0.00%	1,350.95	8.38%	(1,350.95)	-8.38%
1999-2001	8,600.85	0.00	0.00%	1,350.95	15.71%	(1,350.95)	-15.71%
1968-2001	98,569.69	29,727.93	30.16%	7,823.92	7.94%	21,904.01	22.22%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	35
Avg Ret Age	14.6
Years to ASL	20.4
Inflation Factor At 2.75% to ASL	1.74

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	7.88%
1987-2001	15-Year Trend	1.35%
1992-2001	10-Year Trend	-3.90%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R			**0.00%**	**13.80%**	**-13.80%**
1985 Total	8,418.98	(3,534.53)			
LESS:					
Crookston	5,237.85	1,047.45			
Net Activity	3,181.13	(4,581.98)			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 387.1 - Cathodic Protection Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	5,811.75	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	11,739.35	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	1,543.21	(459.00)	-29.74%	112.23	7.27%	(571.23)	-37.02%
1971	10,490.96	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	19,729.18	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	18,059.89	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	9,563.58	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	8,497.19	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	11,454.91	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	17,086.04	0.00	0.00%	13.44	0.08%	(13.44)	-0.08%
1978	15,552.61	0.00	0.00%	15.95	0.10%	(15.95)	-0.10%
1979	8,364.88	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	14,978.92	583.96	3.90%	0.00	0.00%	583.96	3.90%
1981	15,697.01	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	12,740.49	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	15,906.12	0.00	0.00%	499.89	3.14%	(499.89)	-3.14%
1984	20,715.99	0.00	0.00%	615.83	2.97%	(615.83)	-2.97%
1985	21,880.96	(80.47)	-0.37%	2014.67	9.21%	(2,095.14)	-9.58%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	19,054.14	186.00	0.98%	669.05	3.51%	(483.05)	-2.54%
1988	31,269.89	200.00	0.64%	407.10	1.30%	(207.10)	-0.66%
1989	17,992.33	727.66	4.04%	405.51	2.25%	322.15	1.79%
1990	1,264.75	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	23,983.88	1,054.24	4.40%	517.44	2.16%	536.80	2.24%
1992	31,528.72	(220.00)	-0.70%	4193.91	13.30%	(4,413.91)	-14.00%
1993	57,065.06	477.66	0.84%	876.70	1.54%	(399.04)	-0.70%
1994	33,869.58	2,255.32	6.66%	160.59	0.47%	2,094.73	6.18%
1995	7,284.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	24,784.53	477.66	1.93%	295.65	1.19%	182.01	0.73%
1997	18,582.17	478.00	2.57%	27.98	0.15%	450.02	2.42%
1998	15,042.49	0.00	0.00%	44.71	0.30%	(44.71)	-0.30%
1999	18,373.16	0.00	0.00%	133.29	0.73%	(133.29)	-0.73%
2000	18,008.38	0.00	0.00%	104.13	0.58%	(104.13)	-0.58%
2001	20,910.61	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 387.1 - Cathodic Protection Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	19,094.31	(459.00)	-2.40%	112.23	0.59%	(571.23)	-2.99%
1969-1971	23,773.52	(459.00)	-1.93%	112.23	0.47%	(571.23)	-2.40%
1970-1972	31,763.35	(459.00)	-1.45%	112.23	0.35%	(571.23)	-1.80%
1971-1973	48,280.03	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	47,352.65	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	36,120.66	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	29,515.68	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	37,038.14	0.00	0.00%	13.44	0.04%	(13.44)	-0.04%
1976-1978	44,093.56	0.00	0.00%	29.39	0.07%	(29.39)	-0.07%
1977-1979	41,003.53	0.00	0.00%	29.39	0.07%	(29.39)	-0.07%
1978-1980	38,896.41	583.96	1.50%	15.95	0.04%	568.01	1.46%
1979-1981	39,040.81	583.96	1.50%	0.00	0.00%	583.96	1.50%
1980-1982	43,416.42	583.96	1.35%	0.00	0.00%	583.96	1.35%
1981-1983	44,343.62	0.00	0.00%	499.89	1.13%	(499.89)	-1.13%
1982-1984	49,362.60	0.00	0.00%	1115.72	2.26%	(1,115.72)	-2.26%
1983-1985	58,503.07	(80.47)	-0.14%	3130.39	5.35%	(3,210.86)	-5.49%
1984-1986	42,596.95	(80.47)	-0.19%	2630.50	6.18%	(2,710.97)	-6.36%
1985-1987	40,935.10	105.53	0.26%	2683.72	6.56%	(2,578.19)	-6.30%
1986-1988	50,324.03	386.00	0.77%	1076.15	2.14%	(690.15)	-1.37%
1987-1989	68,316.36	1,113.66	1.63%	1481.66	2.17%	(368.00)	-0.54%
1988-1990	50,526.97	927.66	1.84%	812.61	1.61%	115.05	0.23%
1989-1991	43,240.96	1,781.90	4.12%	922.95	2.13%	858.95	1.99%
1990-1992	56,777.35	834.24	1.47%	4711.35	8.30%	(3,877.11)	-6.83%
1991-1993	112,577.66	1,311.90	1.17%	5588.05	4.96%	(4,276.15)	-3.80%
1992-1994	122,463.36	2,512.98	2.05%	5231.20	4.27%	(2,718.22)	-2.22%
1993-1995	98,218.64	2,732.98	2.78%	1037.29	1.06%	1,695.69	1.73%
1994-1996	65,938.11	2,732.98	4.14%	456.24	0.69%	2,276.74	3.45%
1995-1997	50,650.70	955.66	1.89%	323.63	0.64%	632.03	1.25%
1996-1998	58,409.19	955.66	1.64%	368.34	0.63%	587.32	1.01%
1997-1999	51,997.82	478.00	0.92%	205.98	0.40%	272.02	0.52%
1998-2000	51,424.03	0.00	0.00%	282.13	0.55%	(282.13)	-0.55%
1999-2001	57,292.15	0.00	0.00%	237.42	0.41%	(237.42)	-0.41%
1968-2001	578,826.73	5,681.03	0.98%	11,108.07	1.92%	(5,427.04)	-0.94%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	20
Avg Ret Age	13.2
Years to ASL	6.8
Inflation Factor At 2.75% to ASL	1.20

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	1.92%
1987-2001	15-Year Trend	1.34%
1992-2001	10-Year Trend	0.51%
1997-2001	5-Year Trend	-0.73%

Adjusted Salvage & C/O/R			**-0.73%**	**2.31%**	**-3.04%**
1985 Total	35,386.81	10,991.34			
LESS:					
Crookston	13,505.85	11,071.81			
Net Activity	21,880.96	(80.47)			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 387.2 - Other Distribution Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	415.20	(1.98)	-0.48%	88.61	21.34%	(90.59)	-21.82%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	1,924.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	1,155.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	606.13	(149.36)	-24.64%	0.00	0.00%	(149.36)	-24.64%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	2,669.54	321.00	12.02%	0.00	0.00%	321.00	12.02%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	242.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	1,158.36	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	3,481.02	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	962.88	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	2,659.56	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 387.2 - Other Distribution Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	415.20	(1.98)	-0.48%	88.61	21.34%	(90.59)	-21.82%
1976-1978	415.20	(1.98)	-0.48%	88.61	21.34%	(90.59)	-21.82%
1977-1979	415.20	(1.98)	-0.48%	88.61	21.34%	(90.59)	-21.82%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	1,924.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	1,924.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	1,924.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	1,155.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	1,155.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	1,155.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	606.13	(149.36)	-24.64%	0.00	0.00%	(149.36)	-24.64%
1986-1988	606.13	(149.36)	-24.64%	0.00	0.00%	(149.36)	-24.64%
1987-1989	3,275.67	171.64	5.24%	0.00	0.00%	171.64	5.24%
1988-1990	2,669.54	321.00	12.02%	0.00	0.00%	321.00	12.02%
1989-1991	2,669.54	321.00	12.02%	0.00	0.00%	321.00	12.02%
1990-1992	242.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	242.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	1,401.30	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	1,158.36	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	4,639.38	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	4,443.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	4,443.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	3,622.44	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	2,659.56	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	2,659.56	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	15,276.05	169.66	1.11%	88.61	0.58%	81.05	0.53%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	25
Avg Ret Age	18.2
Years to ASL	6.8
Inflation Factor At 2.75% to ASL	1.20

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	1.53%
1987-2001	15-Year Trend	4.67%
1992-2001	10-Year Trend	0.00%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**0.70%**	**-0.70%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 390 - Structures & Improvements

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	4,011.48	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00		0.00%	0.00	0.00%	0.00	0.00%
1970	1,939.40	330.00	17.02%	0.19	0.01%	329.81	17.01%
1971	220.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	5,237.65	0.00	0.00%	98.15	1.87%	(98.15)	-1.87%
1974	3,163.71	0.00	0.00%	455.62	14.40%	(455.62)	-14.40%
1975	1,500.00	0.00	0.00%	62.31	4.15%	(62.31)	-4.15%
1976	150.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	4,154.28	0.00	0.00%	152.88	3.68%	(152.88)	-3.68%
1981	5,991.28	0.00	0.00%	28.54	0.48%	(28.54)	-0.48%
1982	2,768.63	197.20	7.12%	56.80	2.05%	140.40	5.07%
1983	0.00	250.00	0.00%	0.00	0.00%	250.00	0.00%
1984	52,319.71	0.00	0.00%	1,142.50	2.18%	(1,142.50)	-2.18%
1985	10,302.10	(9,978.80)	-96.86%	542.71	5.27%	(10,521.51)	-102.13%
1986	4,959.76	1,000.00	20.16%	327.26	6.60%	672.74	13.56%
1987	100,209.57	0.00	0.00%	85.89	0.09%	(85.89)	-0.09%
1988	107,578.45	40.00	0.04%	2,115.59	1.97%	(2,075.59)	-1.93%
1989	10,343.74	0.00	0.00%	629.80	6.09%	(629.80)	-6.09%
1990	250.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	531.17	0.00	0.00%	107.21	20.18%	(107.21)	-20.18%
1992	4,817.26	(99.41)	-2.06%	2,650.10	55.01%	(2,749.51)	-57.08%
1993	5,081.86	0.00	0.00%	1,859.58	36.59%	(1,859.58)	-36.59%
1994	1,618.38	0.00	0.00%	15.82	0.98%	(15.82)	-0.98%
1995	109,499.69	154,090.00	140.72%	934.46	0.85%	153,155.54	139.87%
1996	138,637.71	196,098.21	141.45%	1,217.79	0.88%	194,880.42	140.57%
1997	9,710.60	0.00	0.00%	577.91	5.95%	(577.91)	-5.95%
1998	6,373.20	0.00	0.00%	1,006.53	15.79%	(1,006.53)	-15.79%
1999	2,036.72	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 390 - Structures & Improvements

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	5,950.88	330.00	5.55%	0.19	0.00%	329.81	5.54%
1969-1971	2,159.40	330.00	15.28%	0.19	0.01%	329.81	15.27%
1970-1972	2,159.40	330.00	15.28%	0.19	0.01%	329.81	15.27%
1971-1973	5,457.65	0.00	0.00%	98.15	1.80%	(98.15)	-1.80%
1972-1974	8,401.36	0.00	0.00%	553.77	6.59%	(553.77)	-6.59%
1973-1975	9,901.36	0.00	0.00%	616.08	6.22%	(616.08)	-6.22%
1974-1976	4,813.71	0.00	0.00%	517.93	10.76%	(517.93)	-10.76%
1975-1977	1,650.00	0.00	0.00%	62.31	3.78%	(62.31)	-3.78%
1976-1978	150.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	4,154.28	0.00	0.00%	152.88	3.68%	(152.88)	-3.68%
1979-1981	10,145.56	0.00	0.00%	181.42	1.79%	(181.42)	-1.79%
1980-1982	12,914.19	197.20	1.53%	238.22	1.84%	(41.02)	-0.32%
1981-1983	8,759.91	447.20	5.11%	85.34	0.97%	361.86	4.13%
1982-1984	55,088.34	447.20	0.81%	1,199.30	2.18%	(752.10)	-1.37%
1983-1985	62,621.81	(9,728.80)	-15.54%	1,685.21	2.69%	(11,414.01)	-18.23%
1984-1986	67,581.57	(8,978.80)	-13.29%	2,012.47	2.98%	(10,991.27)	-16.26%
1985-1987	115,471.43	(8,978.80)	-7.78%	955.86	0.83%	(9,934.66)	-8.60%
1986-1988	212,747.78	1,040.00	0.49%	2,528.74	1.19%	(1,488.74)	-0.70%
1987-1989	218,131.76	40.00	0.02%	2,831.28	1.30%	(2,791.28)	-1.28%
1988-1990	118,172.19	40.00	0.03%	2,745.39	2.32%	(2,705.39)	-2.29%
1989-1991	11,124.91	0.00	0.00%	737.01	6.62%	(737.01)	-6.62%
1990-1992	5,598.43	(99.41)	-1.78%	2,757.31	49.25%	(2,856.72)	-51.03%
1991-1993	10,430.29	(99.41)	-0.95%	4,616.89	44.26%	(4,716.30)	-45.22%
1992-1994	11,517.50	(99.41)	-0.86%	4,525.50	39.29%	(4,624.91)	-40.16%
1993-1995	116,199.93	154,090.00	132.61%	2,809.86	2.42%	151,280.14	130.19%
1994-1996	249,755.78	350,188.21	140.21%	2,168.07	0.87%	348,020.14	139.34%
1995-1997	257,848.00	350,188.21	135.81%	2,730.16	1.06%	347,458.05	134.75%
1996-1998	154,721.51	196,098.21	126.74%	2,802.23	1.81%	193,295.98	124.93%
1997-1999	18,120.52	0.00	0.00%	1,584.44	8.74%	(1,584.44)	-8.74%
1998-2000	8,409.92	0.00	0.00%	1,006.53	11.97%	(1,006.53)	-11.97%
1999-2001	2,036.72	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	593,406.35	341,927.20	57.62%	14,067.64	2.37%	327,859.56	55.25%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	35
Avg Ret Age	21.2
Years to ASL	13.8
Inflation Factor At 2.75% to ASL	1.45

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	69.44%
1987-2001	15-Year Trend	74.49%
1992-2001	10-Year Trend	53.34%
1997-2001	5-Year Trend	-67.00%

Adjusted Salvage & C/O/R			**-67.00%**	**3.45%**	**-70.45%**
1985 Total	82,660.89	488,719.08			
LESS:					
Crookston	72,358.79	42,961.16			
WBI Sale		455,736.72			
Net Activity	10,302.10	(9,978.80)			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 391.1 - Office Furniture & Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	43,540.46	1,283.00	2.95%	0.00	0.00%	1,283.00	2.95%
1969	21,305.65	1,255.00	5.89%	0.00	0.00%	1,255.00	5.89%
1970	15,185.49	1,480.00	9.75%	10.88	0.07%	1,469.12	9.67%
1971	6,861.90	566.00	8.25%	0.00	0.00%	566.00	8.25%
1972	7,013.96	360.50	5.14%	0.00	0.00%	360.50	5.14%
1973	5,517.37	1,037.00	18.80%	0.00	0.00%	1,037.00	18.80%
1974	5,148.32	639.50	12.42%	0.00	0.00%	639.50	12.42%
1975	4,200.21	1,514.01	36.05%	37.69	0.90%	1,476.32	35.15%
1976	6,097.75	1,171.34	19.21%	0.00	0.00%	1,171.34	19.21%
1977	9,405.48	1,114.50	11.85%	0.00	0.00%	1,114.50	11.85%
1978	15,889.19	1,307.50	8.23%	0.00	0.00%	1,307.50	8.23%
1979	11,114.16	765.25	6.89%	0.00	0.00%	765.25	6.89%
1980	9,514.85	726.30	7.63%	0.00	0.00%	726.30	7.63%
1981	7,665.20	463.96	6.05%	(12.53)	-0.16%	476.49	6.22%
1982	4,406.06	455.50	10.34%	0.00	0.00%	455.50	10.34%
1983	22,142.85	1,411.00	6.37%	(60.17)	-0.27%	1,471.17	6.64%
1984	6,973.50	602.00	8.63%	0.00	0.00%	602.00	8.63%
1985	16,613.83	4,822.35	29.03%	0.00	0.00%	4,822.35	29.03%
1986	12,429.91	53.50	0.43%	0.00	0.00%	53.50	0.43%
1987	22,351.51	1,869.84	8.37%	0.00	0.00%	1,869.84	8.37%
1988	12,551.81	117.50	0.94%	0.00	0.00%	117.50	0.94%
1989	2,580.74	10.00	0.39%	0.00	0.00%	10.00	0.39%
1990	2,811.84	395.00	14.05%	0.00	0.00%	395.00	14.05%
1991	20,130.56	2,344.00	11.64%	0.00	0.00%	2,344.00	11.64%
1992	5,186.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	5,640.62	1,045.00	18.53%	0.00	0.00%	1,045.00	18.53%
1994	20,271.56	140.55	0.69%	0.00	0.00%	140.55	0.69%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	42,789.60	1,432.68	3.35%	0.00	0.00%	1,432.68	3.35%
1997	15,785.68	393.95	2.50%	0.00	0.00%	393.95	2.50%
1998	3,235.41	580.00	17.93%	0.00	0.00%	580.00	17.93%
1999	19,673.06	1,309.42	6.66%	0.00	0.00%	1,309.42	6.66%
2000	205.01	35.01	17.08%	0.00	0.00%	35.01	17.08%
2001	29,279.67	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 391.1 - Office Furniture & Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	80,031.60	4,018.00	5.02%	10.88	0.01%	4,007.12	5.01%
1969-1971	43,353.04	3,301.00	7.61%	10.88	0.03%	3,290.12	7.59%
1970-1972	29,061.35	2,406.50	8.28%	10.88	0.04%	2,395.62	8.24%
1971-1973	19,393.23	1,963.50	10.12%	0.00	0.00%	1,963.50	10.12%
1972-1974	17,679.65	2,037.00	11.52%	0.00	0.00%	2,037.00	11.52%
1973-1975	14,865.90	3,190.51	21.46%	37.69	0.25%	3,152.82	21.21%
1974-1976	15,446.28	3,324.85	21.53%	37.69	0.24%	3,287.16	21.28%
1975-1977	19,703.44	3,799.85	19.29%	37.69	0.19%	3,762.16	19.09%
1976-1978	31,392.42	3,593.34	11.45%	0.00	0.00%	3,593.34	11.45%
1977-1979	36,408.83	3,187.25	8.75%	0.00	0.00%	3,187.25	8.75%
1978-1980	36,518.20	2,799.05	7.66%	0.00	0.00%	2,799.05	7.66%
1979-1981	28,294.21	1,955.51	6.91%	(12.53)	-0.04%	1,968.04	6.96%
1980-1982	21,586.11	1,645.76	7.62%	(12.53)	-0.06%	1,658.29	7.68%
1981-1983	34,214.11	2,330.46	6.81%	(72.70)	-0.21%	2,403.16	7.02%
1982-1984	33,522.41	2,468.50	7.36%	(60.17)	-0.18%	2,528.67	7.54%
1983-1985	45,730.18	6,835.35	14.95%	(60.17)	-0.13%	6,895.52	15.08%
1984-1986	36,017.24	5,477.85	15.21%	0.00	0.00%	5,477.85	15.21%
1985-1987	51,395.25	6,745.69	13.13%	0.00	0.00%	6,745.69	13.13%
1986-1988	47,333.23	2,040.84	4.31%	0.00	0.00%	2,040.84	4.31%
1987-1989	37,484.06	1,997.34	5.33%	0.00	0.00%	1,997.34	5.33%
1988-1990	17,944.39	522.50	2.91%	0.00	0.00%	522.50	2.91%
1989-1991	25,523.14	2,749.00	10.77%	0.00	0.00%	2,749.00	10.77%
1990-1992	28,128.53	2,739.00	9.74%	0.00	0.00%	2,739.00	9.74%
1991-1993	30,957.31	3,389.00	10.95%	0.00	0.00%	3,389.00	10.95%
1992-1994	31,098.31	1,185.55	3.81%	0.00	0.00%	1,185.55	3.81%
1993-1995	25,912.18	1,185.55	4.58%	0.00	0.00%	1,185.55	4.58%
1994-1996	63,061.16	1,573.23	2.49%	0.00	0.00%	1,573.23	2.49%
1995-1997	58,575.28	1,826.63	3.12%	0.00	0.00%	1,826.63	3.12%
1996-1998	61,810.69	2,406.63	3.89%	0.00	0.00%	2,406.63	3.89%
1997-1999	38,694.15	2,283.37	5.90%	0.00	0.00%	2,283.37	5.90%
1998-2000	23,113.48	1,924.43	8.33%	0.00	0.00%	1,924.43	8.33%
1999-2001	49,157.74	1,344.43	2.73%	0.00	0.00%	1,344.43	2.73%
1968-2001	433,519.34	30,701.16	7.08%	(24.13)	-0.01%	30,725.29	7.09%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	20
Avg Ret Age	17.5
Years to ASL	2.5
Inflation Factor At 2.75% to ASL	1.07

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	3.69%
1987-2001	15-Year Trend	3.68%
1992-2001	10-Year Trend	3.14%
1997-2001	5-Year Trend	5.89%

Adjusted Salvage & C/O/R			**5.89%**	**-0.01%**	**5.90%**
1985 Total	29,652.73	368,816.58			
LESS:					
Crookston	13,038.90	6,192.02			
WBI Sale	-	357,802.21			
Net Activity	16,613.83	4,822.35			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 391.2 - Computer Equipment - Honeywell

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	6,450.79	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	4,183.64	4,895.22	117.01%	0.00	0.00%	4,895.22	117.01%
1999	2,780.32	620.00	22.30%	0.00	0.00%	620.00	22.30%
2000	212,239.93	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 391.2 - Computer Equipment - Honeywell

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	6,450.79	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	6,450.79	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	6,450.79	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	4,183.64	4,895.22	117.01%	0.00	0.00%	4,895.22	117.01%
1997-1999	6,963.96	5,515.22	79.20%	0.00	0.00%	5,515.22	79.20%
1998-2000	219,203.89	5,515.22	2.52%	0.00	0.00%	5,515.22	2.52%
1999-2001	215,020.25	620.00	0.29%	0.00	0.00%	620.00	0.29%
1968-2001	225,654.68	5,515.22	2.44%	0.00	0.00%	5,515.22	2.44%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	7
Avg Ret Age	11.4
Years to ASL	-4.4
Inflation Factor At 2.75% to ASL	0.89

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	31.72%
1987-2001	15-Year Trend	38.44%
1992-2001	10-Year Trend	45.47%
1997-2001	5-Year Trend	5.63%

Adjusted Salvage & C/O/R	**5.63%**	**0.00%**	**5.63%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account391.3 - Computer Equipment - PC

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	6,233.33	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	4,289.56	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	2,555.93	281.60	11.02%	0.00	0.00%	281.60	11.02%
1998	20,822.07	3,774.68	18.13%	0.00	0.00%	3,774.68	18.13%
1999	65,426.02	580.00	0.89%	0.00	0.00%	580.00	0.89%
2000	11,594.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	42,008.61	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account391.3 - Computer Equipment - PC

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	6,233.33	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	10,522.89	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	13,078.82	281.60	2.15%	0.00	0.00%	281.60	2.15%
1996-1998	27,667.56	4,056.28	14.66%	0.00	0.00%	4,056.28	14.66%
1997-1999	88,804.02	4,636.28	5.22%	0.00	0.00%	4,636.28	5.22%
1998-2000	97,843.03	4,354.68	4.45%	0.00	0.00%	4,354.68	4.45%
1999-2001	119,029.57	580.00	0.49%	0.00	0.00%	580.00	0.49%
1968-2001	152,930.46	4,636.28	3.03%	0.00	0.00%	4,636.28	3.03%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	5
Avg Ret Age	6.3
Years to ASL	-1.3
Inflation Factor At 2.75% to ASL	0.97

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	4.33%
1987-2001	15-Year Trend	5.26%
1992-2001	10-Year Trend	6.29%
1997-2001	5-Year Trend	1.33%

Adjusted Salvage & C/O/R	**1.33%**	**0.00%**	**1.33%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 392.1 -Transportation Equipment (Non-Untiized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	316.00	0.00%	47.25	0.00%	268.75	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	826.93	150.00	18.14%	0.00	0.00%	150.00	18.14%
2001	14,059.66	1,701.00	12.10%	0.00	0.00%	1,701.00	12.10%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 392.1 -Transportation Equipment (Non-Untiized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	316.00	0.00%	47.25	0.00%	268.75	0.00%
1995-1997	0.00	316.00	0.00%	47.25	0.00%	268.75	0.00%
1996-1998	0.00	316.00	0.00%	47.25	0.00%	268.75	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	826.93	150.00	18.14%	0.00	0.00%	150.00	18.14%
1999-2001	14,886.59	1,851.00	12.43%	0.00	0.00%	1,851.00	12.43%
1968-2001	14,886.59	2,167.00	14.56%	47.25	0.32%	2,119.75	14.24%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	8
Avg Ret Age	21.1
Years to ASL	-13.1
Inflation Factor At 2.75% to ASL	0.70

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	5.83%
1987-2001	15-Year Trend	7.63%
1992-2001	10-Year Trend	11.02%
1997-2001	5-Year Trend	19.02%

Adjusted Salvage & C/O/R	**19.02%**	**0.22%**	**18.79%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 392.2 -Transportation Equipment (Untiized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	294,595.14	31,225.71	10.60%	332.01	0.11%	30,893.70	10.49%
1996	386,586.06	94,300.22	24.39%	3,363.10	0.87%	90,937.12	23.52%
1997	202,459.15	35,010.10	17.29%	409.73	0.20%	34,600.37	17.09%
1998	436,818.58	106,096.36	24.29%	1,086.25	0.25%	105,010.11	24.04%
1999	349,200.70	56,912.97	16.30%	1,161.44	0.33%	55,751.53	15.97%
2000	706,714.53	124,990.96	17.69%	794.80	0.11%	124,196.16	17.57%
2001	481,092.35	84,394.75	17.54%	1,370.15	0.28%	83,024.60	17.26%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 392.2 -Transportation Equipment (Untiized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	294,595.14	31,225.71	10.60%	332.01	0.11%	30,893.70	10.49%
1994-1996	681,181.20	125,525.93	18.43%	3,695.11	0.54%	121,830.82	17.89%
1995-1997	883,640.35	160,536.03	18.17%	4,104.84	0.46%	156,431.19	17.70%
1996-1998	1,025,863.79	235,406.68	22.95%	4,859.08	0.47%	230,547.60	22.47%
1997-1999	988,478.43	198,019.43	20.03%	2,657.42	0.27%	195,362.01	19.76%
1998-2000	1,492,733.81	288,000.29	19.29%	3,042.49	0.20%	284,957.80	19.09%
1999-2001	1,537,007.58	266,298.68	17.33%	3,326.39	0.22%	262,972.29	17.11%
1968-2001	2,857,466.51	532,931.07	18.65%	8,517.48	0.30%	524,413.59	18.35%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	6
Avg Ret Age	10.9
Years to ASL	-4.9
Inflation Factor At 2.75% to ASL	0.88

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	19.73%
1987-2001	15-Year Trend	23.62%
1992-2001	10-Year Trend	26.94%
1997-2001	5-Year Trend	17.95%

Adjusted Salvage & C/O/R	**17.95%**	**0.26%**	**17.69%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 393 - Stores Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	1,200.80	0.00	0.00%	2141.19	178.31%	(2,141.19)	-178.31%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	2,124.95	0.00%	0.00	0.00%	2,124.95	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 393 - Stores Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	1,200.80	0.00	0.00%	2141.19	178.31%	(2,141.19)	-178.31%
1979-1981	1,200.80	0.00	0.00%	2141.19	178.31%	(2,141.19)	-178.31%
1980-1982	1,200.80	0.00	0.00%	2141.19	178.31%	(2,141.19)	-178.31%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	2,124.95	0.00%	0.00	0.00%	2,124.95	0.00%
1984-1986	0.00	2,124.95	0.00%	0.00	0.00%	2,124.95	0.00%
1985-1987	0.00	2,124.95	0.00%	0.00	0.00%	2,124.95	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	1,200.80	2,124.95	176.96%	2,141.19	178.31%	(16.24)	-1.35%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	35
Avg Ret Age	19.5
Years to ASL	15.5
Inflation Factor At 2.75% to ASL	1.52

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.00%
1987-2001	15-Year Trend	0.00%
1992-2001	10-Year Trend	0.00%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R			**0.00%**	**271.52%**	**-271.52%**
1985 Total	72.21	2,141.80			
LESS:					
Crookston	72.21	16.85			
Net Activity	0.00	2,124.95			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Total Account 394 - Tools, Shop & Garage Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	2,270.84	100.00	4.40%	0.00	0.00%	100.00	4.40%
1969	4,531.07	1,387.50	30.62%	0.00	0.00%	1,387.50	30.62%
1970	13,281.18	2,623.95	19.76%	0.41	0.00%	2,623.54	19.75%
1971	8,948.81	2,060.30	23.02%	32.43	0.36%	2,027.87	22.66%
1972	18,450.37	5,341.00	28.95%	0.00	0.00%	5,341.00	28.95%
1973	18,633.03	4,521.00	24.26%	28.74	0.15%	4,492.26	24.11%
1974	3,715.33	707.78	19.05%	0.00	0.00%	707.78	19.05%
1975	7,002.85	1,222.00	17.45%	0.00	0.00%	1,222.00	17.45%
1976	967.00	70.00	7.24%	0.00	0.00%	70.00	7.24%
1977	8,786.34	850.00	9.67%	0.00	0.00%	850.00	9.67%
1978	8,396.86	1,009.00	12.02%	28.73	0.34%	980.27	11.67%
1979	4,437.50	3,220.00	72.56%	0.00	0.00%	3,220.00	72.56%
1980	10,249.64	600.00	5.85%	0.00	0.00%	600.00	5.85%
1981	15,210.38	8,218.74	54.03%	120.65	0.79%	8,098.09	53.24%
1982	12,167.11	2,837.00	23.32%	30.76	0.25%	2,806.24	23.06%
1983	14,224.82	2,724.63	19.15%	0.00	0.00%	2,724.63	19.15%
1984	22,642.01	4,347.00	19.20%	0.00	0.00%	4,347.00	19.20%
1985	12,931.82	6,673.36	51.60%	70.29	0.54%	6,603.07	51.06%
1986	11,524.48	2,084.36	18.09%	39.34	0.34%	2,045.02	17.75%
1987	10,250.18	2,872.00	28.02%	156.17	1.52%	2,715.83	26.50%
1988	44,751.78	10,088.00	22.54%	340.27	0.76%	9,747.73	21.78%
1989	21,088.20	4,550.00	21.58%	5.22	0.02%	4,544.78	21.55%
1990	6,976.09	446.36	6.40%	55.61	0.80%	390.75	5.60%
1991	41,263.15	7,088.06	17.18%	62.68	0.15%	7,025.38	17.03%
1992	30,112.95	3,300.00	10.96%	59.36	0.20%	3,240.64	10.76%
1993	31,143.95	3,310.00	10.63%	41.46	0.13%	3,268.54	10.49%
1994	31,107.44	1,552.11	4.99%	45.79	0.15%	1,506.32	4.84%
1995	11,629.55	3,160.00	27.17%	33.65	0.29%	3,126.35	26.88%
1996	62,743.19	10,492.61	16.72%	100.00	0.16%	10,392.61	16.56%
1997	26,833.07	4,787.42	17.84%	0.00	0.00%	4,787.42	17.84%
1998	34,239.39	7,467.00	21.81%	146.71	0.43%	7,320.29	21.38%
1999	38,905.93	5,015.00	12.89%	107.79	0.28%	4,907.21	12.61%
2000	46,285.61	12,018.00	25.96%	0.00	0.00%	12,018.00	25.96%
2001	34,063.01	2,832.54	8.32%	0.00	0.00%	2,832.54	8.32%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 394.1 - Tools, Shop & Garage Equipment (Non-Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	12,668.96	2,557.45	20.19%	0.41	0.00%	2,557.04	20.18%
1969-1971	11,418.63	2,765.75	24.22%	0.41	0.00%	2,765.34	24.22%
1970-1972	15,808.84	2,328.25	14.73%	0.41	0.00%	2,327.84	14.72%
1971-1973	16,947.45	4,684.30	27.64%	0.00	0.00%	4,684.30	27.64%
1972-1974	16,878.14	4,426.00	26.22%	0.00	0.00%	4,426.00	26.22%
1973-1975	14,984.96	4,176.00	27.87%	0.00	0.00%	4,176.00	27.87%
1974-1976	5,180.30	270.00	5.21%	0.00	0.00%	270.00	5.21%
1975-1977	9,541.91	445.00	4.66%	0.00	0.00%	445.00	4.66%
1976-1978	12,313.79	565.00	4.59%	0.00	0.00%	565.00	4.59%
1977-1979	12,110.45	695.00	5.74%	0.00	0.00%	695.00	5.74%
1978-1980	13,859.30	470.00	3.39%	0.00	0.00%	470.00	3.39%
1979-1981	18,079.02	6,988.74	38.66%	0.00	0.00%	6,988.74	38.66%
1980-1982	24,494.70	7,588.74	30.98%	0.00	0.00%	7,588.74	30.98%
1981-1983	25,344.70	7,675.37	30.28%	0.00	0.00%	7,675.37	30.28%
1982-1984	19,964.93	1,794.63	8.99%	0.00	0.00%	1,794.63	8.99%
1983-1985	17,632.95	1,025.14	5.81%	0.00	0.00%	1,025.14	5.81%
1984-1986	17,721.01	1,772.87	10.00%	0.00	0.00%	1,772.87	10.00%
1985-1987	16,555.97	864.87	5.22%	156.17	0.94%	708.70	4.28%
1986-1988	16,200.51	1,286.36	7.94%	209.66	1.29%	1,076.70	6.65%
1987-1989	17,281.45	1,852.00	10.72%	209.66	1.21%	1,642.34	9.50%
1988-1990	13,951.33	1,852.00	13.27%	53.49	0.38%	1,798.51	12.89%
1989-1991	17,990.63	3,217.07	17.88%	62.68	0.35%	3,154.39	17.53%
1990-1992	18,344.99	1,917.07	10.45%	62.68	0.34%	1,854.39	10.11%
1991-1993	38,441.81	2,202.07	5.73%	62.68	0.16%	2,139.39	5.57%
1992-1994	35,594.32	425.00	1.19%	0.00	0.00%	425.00	1.19%
1993-1995	26,159.30	325.00	1.24%	0.00	0.00%	325.00	1.24%
1994-1996	28,162.43	1,187.96	4.22%	0.00	0.00%	1,187.96	4.22%
1995-1997	33,411.67	3,271.38	9.79%	0.00	0.00%	3,271.38	9.79%
1996-1998	39,826.81	4,710.38	11.83%	0.00	0.00%	4,710.38	11.83%
1997-1999	43,638.61	3,587.42	8.22%	0.00	0.00%	3,587.42	8.22%
1998-2000	57,040.07	7,354.00	12.89%	0.00	0.00%	7,354.00	12.89%
1999-2001	66,026.89	5,915.00	8.96%	0.00	0.00%	5,915.00	8.96%
1968-2001	264,673.97	32,374.44	12.23%	272.75	0.10%	32,101.69	12.13%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	25
Avg Ret Age	15.7
Years to ASL	9.3
Inflation Factor At 2.75% to ASL	1.29

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	4.60%
1987-2001	15-Year Trend	8.53%
1992-2001	10-Year Trend	11.09%
1997-2001	5-Year Trend	10.16%

Adjusted Salvage & C/O/R			**10.16%**	**0.13%**	**10.03%**
1985 Total	33,908.13	578,609.83			
LESS:					
Crookston	29,060.77	18,864.16			
WBI Sale		559,715.16			
Net Activity	4,847.36	30.51			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 394.2 - Tools, Shop & Garage Equipment (Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	-	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	3,766.00	550.00	14.60%	0.00	0.00%	550.00	14.60%
1970	3,648.13	1,004.00	27.52%	0.00	0.00%	1,004.00	27.52%
1971	7,928.30	1,752.00	22.10%	32.43	0.41%	1,719.57	21.69%
1972	13,295.09	4,941.00	37.16%	0.00	0.00%	4,941.00	37.16%
1973	7,861.37	545.00	6.93%	28.74	0.37%	516.26	6.57%
1974	2,764.13	657.78	23.80%	0.00	0.00%	657.78	23.80%
1975	3,740.75	1,072.00	28.66%	0.00	0.00%	1,072.00	28.66%
1976	-	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	3,473.53	625.00	17.99%	0.00	0.00%	625.00	17.99%
1978	2,362.88	739.00	31.28%	28.73	1.22%	710.27	30.06%
1979	3,673.84	3,020.00	82.20%	0.00	0.00%	3,020.00	82.20%
1980	3,187.98	600.00	18.82%	0.00	0.00%	600.00	18.82%
1981	4,956.68	1,430.00	28.85%	120.65	2.43%	1,309.35	26.42%
1982	4,987.77	2,037.00	40.84%	30.76	0.62%	2,006.24	40.22%
1983	6,313.16	2,638.00	41.79%	0.00	0.00%	2,638.00	41.79%
1984	17,768.08	3,439.00	19.35%	0.00	0.00%	3,439.00	19.35%
1985	8,084.46	6,642.85	82.17%	70.29	0.87%	6,572.56	81.30%
1986	3,524.76	1,250.00	35.46%	39.34	1.12%	1,210.66	34.35%
1987	6,541.29	2,872.00	43.91%	0.00	0.00%	2,872.00	43.91%
1988	2,388.16	1,136.00	47.57%	0.00	0.00%	1,136.00	47.57%
1989	12,007.54	3,150.00	26.23%	5.22	0.04%	3,144.78	26.19%
1990	6,597.32	446.36	6.77%	55.61	0.84%	390.75	5.92%
1991	4,600.09	1,270.99	27.63%	0.00	0.00%	1,270.99	27.63%
1992	20,677.93	3,200.00	15.48%	59.36	0.29%	3,140.64	15.19%
1993	10,668.36	3,025.00	28.35%	41.46	0.39%	2,983.54	27.97%
1994	17,231.50	1,512.11	8.78%	45.79	0.27%	1,466.32	8.51%
1995	11,629.55	3,160.00	27.17%	0.00	0.00%	3,160.00	27.17%
1996	12,237.01	3,285.00	26.84%	100.00	0.82%	3,185.00	26.03%
1997	15,900.12	2,664.00	16.75%	0.00	0.00%	2,664.00	16.75%
1998	27,824.25	6,028.00	21.66%	146.71	0.53%	5,881.29	21.14%
1999	11,961.00	4,840.00	40.46%	107.79	0.90%	4,732.21	39.56%
2000	21,951.20	6,128.00	27.92%	0.00	0.00%	6,128.00	27.92%
2001	18,661.05	2,832.54	15.18%	0.00	0.00%	2,832.54	15.18%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 394.2 - Tools, Shop & Garage Equipment (Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	7,414.13	1,554.00	20.96%	0.00	0.00%	1,554.00	20.96%
1969-1971	15,342.43	3,306.00	21.55%	32.43	0.21%	3,273.57	21.34%
1970-1972	24,871.52	7,697.00	30.95%	32.43	0.13%	7,664.57	30.82%
1971-1973	29,084.76	7,238.00	24.89%	61.17	0.21%	7,176.83	24.68%
1972-1974	23,920.59	6,143.78	25.68%	28.74	0.12%	6,115.04	25.56%
1973-1975	14,366.25	2,274.78	15.83%	28.74	0.20%	2,246.04	15.63%
1974-1976	6,504.88	1,729.78	26.59%	0.00	0.00%	1,729.78	26.59%
1975-1977	7,214.28	1,697.00	23.52%	0.00	0.00%	1,697.00	23.52%
1976-1978	5,836.41	1,364.00	23.37%	28.73	0.49%	1,335.27	22.88%
1977-1979	9,510.25	4,384.00	46.10%	28.73	0.30%	4,355.27	45.80%
1978-1980	9,224.70	4,359.00	47.25%	28.73	0.31%	4,330.27	46.94%
1979-1981	11,818.50	5,050.00	42.73%	120.65	1.02%	4,929.35	41.71%
1980-1982	13,132.43	4,067.00	30.97%	151.41	1.15%	3,915.59	29.82%
1981-1983	16,257.61	6,105.00	37.55%	151.41	0.93%	5,953.59	36.62%
1982-1984	29,069.01	8,114.00	27.91%	30.76	0.11%	8,083.24	27.81%
1983-1985	32,165.70	12,719.85	39.54%	70.29	0.22%	12,649.56	39.33%
1984-1986	29,377.30	11,331.85	38.57%	109.63	0.37%	11,222.22	38.20%
1985-1987	18,150.51	10,764.85	59.31%	109.63	0.60%	10,655.22	58.70%
1986-1988	12,454.21	5,258.00	42.22%	39.34	0.32%	5,218.66	41.90%
1987-1989	20,936.99	7,158.00	34.19%	5.22	0.02%	7,152.78	34.16%
1988-1990	20,993.02	4,732.36	22.54%	60.83	0.29%	4,671.53	22.25%
1989-1991	23,204.95	4,867.35	20.98%	60.83	0.26%	4,806.52	20.71%
1990-1992	31,875.34	4,917.35	15.43%	114.97	0.36%	4,802.38	15.07%
1991-1993	35,946.38	7,495.99	20.85%	100.82	0.28%	7,395.17	20.57%
1992-1994	48,577.79	7,737.11	15.93%	146.61	0.30%	7,590.50	15.63%
1993-1995	39,529.41	7,697.11	19.47%	87.25	0.22%	7,609.86	19.25%
1994-1996	41,098.06	7,957.11	19.36%	145.79	0.35%	7,811.32	19.01%
1995-1997	39,766.68	9,109.00	22.91%	100.00	0.25%	9,009.00	22.65%
1996-1998	55,961.38	11,977.00	21.40%	246.71	0.44%	11,730.29	20.96%
1997-1999	55,685.37	13,532.00	24.30%	254.50	0.46%	13,277.50	23.84%
1998-2000	61,736.45	16,996.00	27.53%	254.50	0.41%	16,741.50	27.12%
1999-2001	52,573.25	13,800.54	26.25%	107.79	0.21%	13,692.75	26.05%
1968-2001	302,213.28	78,492.63	25.97%	912.88	0.30%	77,579.75	25.67%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	20
Avg Ret Age	19.5
Years to ASL	0.5
Inflation Factor At 2.75% to ASL	1.01

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	17.76%
1987-2001	15-Year Trend	15.86%
1992-2001	10-Year Trend	27.85%
1997-2001	5-Year Trend	28.32%

Adjusted Salvage & C/O/R			**28.32%**	**0.31%**	**28.02%**
1985 Total	14,878.08	23,232.71			
LESS:					
Crookston	6,793.62	112.50			
WBI Sale		16,477.36			
Net Activity	8,084.46	6,642.85			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 394.3 - Vehicle Maintenance Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	654.41	150.00	22.92%	0.00	0.00%	150.00	22.92%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 394.3 - Vehicle Maintenance Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	654.41	150.00	22.92%	0.00	0.00%	150.00	22.92%
1998-2000	654.41	150.00	22.92%	0.00	0.00%	150.00	22.92%
1999-2001	654.41	150.00	22.92%	0.00	0.00%	150.00	22.92%
1968-2001	654.41	150.00	22.92%	0.00	0.00%	150.00	22.92%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	20
Avg Ret Age	10.5
Years to ASL	9.5
Inflation Factor At 2.75% to ASL	1.29

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	12.67%
1987-2001	15-Year Trend	16.37%
1992-2001	10-Year Trend	22.92%
1997-2001	5-Year Trend	34.38%

Adjusted Salvage & C/O/R	**34.38%**	**0.00%**	**34.38%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 394.4 - Vehicle Refueling Equipement

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	37,871.72	8,500.00	22.44%	286.78	0.76%	8,213.22	21.69%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	28,131.86	4,000.00	14.22%	0.00	0.00%	4,000.00	14.22%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	8,192.23	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	33.65	0.00%	(33.65)	0.00%
1996	28,027.46	6,059.65	21.62%	0.00	0.00%	6,059.65	21.62%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 394.4 - Vehicle Refueling Equipement

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	37,871.72	8,500.00	22.44%	286.78	0.76%	8,213.22	21.69%
1987-1989	37,871.72	8,500.00	22.44%	286.78	0.76%	8,213.22	21.69%
1988-1990	37,871.72	8,500.00	22.44%	286.78	0.76%	8,213.22	21.69%
1989-1991	28,131.86	4,000.00	14.22%	0.00	0.00%	4,000.00	14.22%
1990-1992	28,131.86	4,000.00	14.22%	0.00	0.00%	4,000.00	14.22%
1991-1993	28,131.86	4,000.00	14.22%	0.00	0.00%	4,000.00	14.22%
1992-1994	8,192.23	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	8,192.23	0.00	0.00%	33.65	0.41%	(33.65)	-0.41%
1994-1996	36,219.69	6,059.65	16.73%	33.65	0.09%	6,026.00	16.64%
1995-1997	28,027.46	6,059.65	21.62%	33.65	0.12%	6,026.00	21.50%
1996-1998	28,027.46	6,059.65	21.62%	0.00	0.00%	6,059.65	21.62%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	102,223.27	18,559.65	18.16%	320.43	0.31%	18,239.22	17.84%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	15
Avg Ret Age	7.3
Years to ASL	7.7
Inflation Factor At 2.75% to ASL	1.23

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	11.46%
1987-2001	15-Year Trend	4.55%
1992-2001	10-Year Trend	3.58%
1997-2001	5-Year Trend	-10.81%

Adjusted Salvage & C/O/R	**-10.81%**	**0.39%**	**-11.20%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 395 - Laboratory Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	9,436.63	6,732.00	71.34%	0.00	0.00%	6,732.00	71.34%
1969	1,617.40	3,095.94	191.41%	37.32	2.31%	3,058.62	189.11%
1970	1,253.43	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	161.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	380.81	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	463.03	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	998.11	0.00	0.00%	131.13	13.14%	(131.13)	-13.14%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	146.84	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	7,728.84	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	341.72	0.00	0.00%	(7.10)	-2.08%	7.10	2.08%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	(1.35)	0.00%	0.00	0.00%	(1.35)	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	508.38	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	561.18	0.00	0.00%	5.06	0.90%	(5.06)	-0.90%
1989	1,179.49	0.00	0.00%	46.62	3.95%	(46.62)	-3.95%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	54,824.34	1,000.00	1.82%	286.74	0.52%	713.26	1.30%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	8,427.05	500.00	5.93%	0.00	0.00%	500.00	5.93%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 395 - Laboratory Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	12,307.46	9,827.94	79.85%	37.32	0.30%	9,790.62	79.55%
1969-1971	2,870.83	3,095.94	107.84%	37.32	1.30%	3,058.62	106.54%
1970-1972	1,414.43	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	161.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	161.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	380.81	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	843.84	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	843.84	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	1,461.14	0.00	0.00%	131.13	8.97%	(131.13)	-8.97%
1977-1979	998.11	0.00	0.00%	131.13	13.14%	(131.13)	-13.14%
1978-1980	1,144.95	0.00	0.00%	131.13	11.45%	(131.13)	-11.45%
1979-1981	146.84	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	7,875.68	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	8,070.56	0.00	0.00%	(7.10)	-0.09%	7.10	0.09%
1982-1984	8,070.56	0.00	0.00%	(7.10)	-0.09%	7.10	0.09%
1983-1985	341.72	(1.35)	-0.40%	(7.10)	-2.08%	5.75	1.68%
1984-1986	0.00	(1.35)	0.00%	0.00	0.00%	(1.35)	0.00%
1985-1987	508.38	(1.35)	-0.27%	0.00	0.00%	(1.35)	-0.27%
1986-1988	1,069.56	0.00	0.00%	5.06	0.47%	(5.06)	-0.47%
1987-1989	2,249.05	0.00	0.00%	51.68	2.30%	(51.68)	-2.30%
1988-1990	1,740.67	0.00	0.00%	51.68	2.97%	(51.68)	-2.97%
1989-1991	1,179.49	0.00	0.00%	46.62	3.95%	(46.62)	-3.95%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	54,824.34	1,000.00	1.82%	286.74	0.52%	713.26	1.30%
1994-1996	54,824.34	1,000.00	1.82%	286.74	0.52%	713.26	1.30%
1995-1997	54,824.34	1,000.00	1.82%	286.74	0.52%	713.26	1.30%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	8,427.05	500.00	5.93%	0.00	0.00%	500.00	5.93%
1968-2001	88,028.25	11,326.59	12.87%	499.77	0.57%	10,826.82	12.30%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	20
Avg Ret Age	11.9
Years to ASL	8.1
Inflation Factor At 2.75% to ASL	1.25

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	1.88%
1987-2001	15-Year Trend	2.30%
1992-2001	10-Year Trend	2.74%
1997-2001	5-Year Trend	4.02%

Adjusted Salvage & C/O/R			**4.02%**	**0.71%**	**3.31%**
1985 Total	674.89	82,196.07			
LESS:					
Crookston	674.89	160.86			
WBI Sale		82,036.56			
Net Activity	0.00	(1.35)			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 396.1 - Work Equipment - Trailers

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	101.99	0.00%	0.00	0.00%	101.99	0.00%
1997	15,108.23	8,030.00	53.15%	0.00	0.00%	8,030.00	53.15%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	16,315.67	7,500.00	45.97%	0.00	0.00%	7,500.00	45.97%
2000	1,334.52	450.00	33.72%	0.00	0.00%	450.00	33.72%
2001	6,275.36	2,059.88	32.82%	149.20	2.38%	1,910.68	30.45%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 396.1 - Work Equipment - Trailers

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	101.99	0.00%	0.00	0.00%	101.99	0.00%
1995-1997	15,108.23	8,131.99	53.82%	0.00	0.00%	8,131.99	53.82%
1996-1998	15,108.23	8,131.99	53.82%	0.00	0.00%	8,131.99	53.82%
1997-1999	31,423.90	15,530.00	49.42%	0.00	0.00%	15,530.00	49.42%
1998-2000	17,650.19	7,950.00	45.04%	0.00	0.00%	7,950.00	45.04%
1999-2001	23,925.55	10,009.88	41.84%	149.20	0.62%	9,860.68	41.21%
1968-2001	39,033.78	18,141.87	46.48%	149.20	0.38%	17,992.67	46.10%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	10
Avg Ret Age	8.5
Years to ASL	1.5
Inflation Factor At 2.75% to ASL	1.04

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	40.57%
1987-2001	15-Year Trend	50.18%
1992-2001	10-Year Trend	62.87%
1997-2001	5-Year Trend	38.96%

Adjusted Salvage & C/O/R	**38.96%**	**0.40%**	**38.56%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 396.2 - Power Operated Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	7,624.55	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	18,036.43	4,660.75	25.84%	0.00	0.00%	4,660.75	25.84%
1970	85,745.78	20,081.65	23.42%	2.56	0.00%	20,079.09	23.42%
1971	32,522.96	16,959.50	52.15%	0.00	0.00%	16,959.50	52.15%
1972	68,343.72	34,167.38	49.99%	0.00	0.00%	34,167.38	49.99%
1973	19,453.17	1,321.00	6.79%	0.00	0.00%	1,321.00	6.79%
1974	70,200.13	36,952.50	52.64%	0.00	0.00%	36,952.50	52.64%
1975	48,205.77	23,256.00	48.24%	0.00	0.00%	23,256.00	48.24%
1976	36,542.30	16,760.00	45.86%	21.00	0.06%	16,739.00	45.81%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	21,151.37	11,502.00	54.38%	0.00	0.00%	11,502.00	54.38%
1979	57,535.68	20,150.00	35.02%	0.00	0.00%	20,150.00	35.02%
1980	33,055.15	16,318.30	49.37%	0.00	0.00%	16,318.30	49.37%
1981	187,078.07	133,470.40	71.34%	0.00	0.00%	133,470.40	71.34%
1982	82,780.89	38,429.13	46.42%	0.00	0.00%	38,429.13	46.42%
1983	93,278.27	89,865.50	96.34%	0.00	0.00%	89,865.50	96.34%
1984	65,798.80	36,885.83	56.06%	455.00	0.69%	36,430.83	55.37%
1985	58,997.38	19,690.55	33.38%	0.00	0.00%	19,690.55	33.38%
1986	43,816.13	38,509.33	87.89%	0.00	0.00%	38,509.33	87.89%
1987	60,103.95	21,504.91	35.78%	211.74	0.35%	21,293.17	35.43%
1988	351,349.08	97,992.00	27.89%	698.08	0.20%	97,293.92	27.69%
1989	659,158.69	406,813.00	61.72%	232.86	0.04%	406,580.14	61.68%
1990	465,530.32	426,773.25	91.67%	191.71	0.04%	426,581.54	91.63%
1991	506,039.47	434,830.37	85.93%	27.47	0.01%	434,802.90	85.92%
1992	347,508.62	243,091.00	69.95%	131.21	0.04%	242,959.79	69.91%
1993	537,705.71	474,364.03	88.22%	0.00	0.00%	474,364.03	88.22%
1994	444,780.98	374,784.00	84.26%	29.22	0.01%	374,754.78	84.26%
1995	757,408.90	775,939.25	102.45%	10.00	0.00%	775,929.25	102.45%
1996	847,905.78	632,158.36	74.56%	426.88	0.05%	631,731.48	74.50%
1997	1,288,447.77	1,287,216.85	99.90%	0.00	0.00%	1,287,216.85	99.90%
1998	635,435.44	520,006.27	81.83%	216.70	0.03%	519,789.57	81.80%
1999	1,644,011.39	1,296,953.70	78.89%	16,944.81	1.03%	1,280,008.89	77.86%
2000	578,648.60	446,315.01	77.13%	0.00	0.00%	446,315.01	77.13%
2001	1,350,062.37	1,118,466.41	82.85%	1,185.02	0.09%	1,117,281.39	82.76%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 396.2 - Power Operated Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	111,406.76	24,742.40	22.21%	2.56	0.00%	24,739.84	22.21%
1969-1971	136,305.17	41,701.90	30.59%	2.56	0.00%	41,699.34	30.59%
1970-1972	186,612.46	71,208.53	38.16%	2.56	0.00%	71,205.97	38.16%
1971-1973	120,319.85	52,447.88	43.59%	0.00	0.00%	52,447.88	43.59%
1972-1974	157,997.02	72,440.88	45.85%	0.00	0.00%	72,440.88	45.85%
1973-1975	137,859.07	61,529.50	44.63%	0.00	0.00%	61,529.50	44.63%
1974-1976	154,948.20	76,968.50	49.67%	21.00	0.01%	76,947.50	49.66%
1975-1977	84,748.07	40,016.00	47.22%	21.00	0.02%	39,995.00	47.19%
1976-1978	57,693.67	28,262.00	48.99%	21.00	0.04%	28,241.00	48.95%
1977-1979	78,687.05	31,652.00	40.23%	0.00	0.00%	31,652.00	40.23%
1978-1980	111,742.20	47,970.30	42.93%	0.00	0.00%	47,970.30	42.93%
1979-1981	277,668.90	169,938.70	61.20%	0.00	0.00%	169,938.70	61.20%
1980-1982	302,914.11	188,217.83	62.14%	0.00	0.00%	188,217.83	62.14%
1981-1983	363,137.23	261,765.03	72.08%	0.00	0.00%	261,765.03	72.08%
1982-1984	241,857.96	165,180.46	68.30%	455.00	0.19%	164,725.46	68.11%
1983-1985	218,074.45	146,441.88	67.15%	455.00	0.21%	145,986.88	66.94%
1984-1986	168,612.31	95,085.71	56.39%	455.00	0.27%	94,630.71	56.12%
1985-1987	162,917.46	79,704.79	48.92%	211.74	0.13%	79,493.05	48.79%
1986-1988	455,269.16	158,006.24	34.71%	909.82	0.20%	157,096.42	34.51%
1987-1989	1,070,611.72	526,309.91	49.16%	1,142.68	0.11%	525,167.23	49.05%
1988-1990	1,476,038.09	931,578.25	63.11%	1,122.65	0.08%	930,455.60	63.04%
1989-1991	1,630,728.48	1,268,416.62	77.78%	452.04	0.03%	1,267,964.58	77.75%
1990-1992	1,319,078.41	1,104,694.62	83.75%	350.39	0.03%	1,104,344.23	83.72%
1991-1993	1,391,253.80	1,152,285.40	82.82%	158.68	0.01%	1,152,126.72	82.81%
1992-1994	1,329,995.31	1,092,239.03	82.12%	160.43	0.01%	1,092,078.60	82.11%
1993-1995	1,739,895.59	1,625,087.28	93.40%	39.22	0.00%	1,625,048.06	93.40%
1994-1996	2,050,095.66	1,782,881.61	86.97%	466.10	0.02%	1,782,415.51	86.94%
1995-1997	2,893,762.45	2,695,314.46	93.14%	436.88	0.02%	2,694,877.58	93.13%
1996-1998	2,771,788.99	2,439,381.48	88.01%	643.58	0.02%	2,438,737.90	87.98%
1997-1999	3,567,894.60	3,104,176.82	87.00%	17,161.51	0.48%	3,087,015.31	86.52%
1998-2000	2,858,095.43	2,263,274.98	79.19%	17,161.51	0.60%	2,246,113.47	78.59%
1999-2001	3,572,722.36	2,861,735.12	80.10%	18,129.83	0.51%	2,843,605.29	79.59%
1968-2001	11,504,263.62	9,116,188.23	79.24%	20,784.26	0.18%	9,095,403.97	79.06%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	5
Avg Ret Age	5.0
Years to ASL	0.0
Inflation Factor At 2.75% to ASL	1.00

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	91.77%
1987-2001	15-Year Trend	99.26%
1992-2001	10-Year Trend	84.19%
1997-2001	5-Year Trend	75.02%

Adjusted Salvage & C/O/R			**75.02%**	**0.18%**	**74.84%**
1985 Total	94,217.44	294,281.75			
LESS:					
Crookston	35,220.06	24,196.66			
WBI Sale		250,394.54			
Net Activity	58,997.38	19,690.55			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 397.1 - Communication Equipment (Fixed Radios)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	44,237.04	148.00	0.33%	808.26	1.83%	(660.26)	-1.49%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	8,228.01	3,720.36	45.22%	332.27	4.04%	3,388.09	41.18%
1993	13,035.20	170.36	1.31%	1,183.92	9.08%	(1,013.56)	-7.78%
1994	7,505.95	2,300.00	30.64%	531.27	7.08%	1,768.73	23.56%
1995	2,192.28	0.00	0.00%	61.95	2.83%	(61.95)	-2.83%
1996	9,056.63	0.00	0.00%	427.22	4.72%	(427.22)	-4.72%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	8,797.35	1,500.00	17.05%	91.95	1.05%	1,408.05	16.01%
1999	4,006.08	250.00	6.24%	2,197.64	54.86%	(1,947.64)	-48.62%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 397.1 - Communication Equipment (Fixed Radios)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	44,237.04	148.00	0.33%	808.26	1.83%	(660.26)	-1.49%
1985-1987	44,237.04	148.00	0.33%	808.26	1.83%	(660.26)	-1.49%
1986-1988	44,237.04	148.00	0.33%	808.26	1.83%	(660.26)	-1.49%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	8,228.01	3,720.36	45.22%	332.27	4.04%	3,388.09	41.18%
1991-1993	21,263.21	3,890.72	18.30%	1,516.19	7.13%	2,374.53	11.17%
1992-1994	28,769.16	6,190.72	21.52%	2,047.46	7.12%	4,143.26	14.40%
1993-1995	22,733.43	2,470.36	10.87%	1,777.14	7.82%	693.22	3.05%
1994-1996	18,754.86	2,300.00	12.26%	1,020.44	5.44%	1,279.56	6.82%
1995-1997	11,248.91	0.00	0.00%	489.17	4.35%	(489.17)	-4.35%
1996-1998	17,853.98	1,500.00	8.40%	519.17	2.91%	980.83	5.49%
1997-1999	12,803.43	1,750.00	13.67%	2,289.59	17.88%	(539.59)	-4.21%
1998-2000	12,803.43	1,750.00	13.67%	2,289.59	17.88%	(539.59)	-4.21%
1999-2001	4,006.08	250.00	6.24%	2,197.64	54.86%	(1,947.64)	-48.62%
1968-2001	97,058.54	8,088.72	8.33%	5,634.48	5.81%	2,454.24	2.53%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	15
Avg Ret Age	16.3
Years to ASL	-1.3
Inflation Factor At 2.75% to ASL	0.97

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	15.85%
1987-2001	15-Year Trend	14.34%
1992-2001	10-Year Trend	0.28%
1997-2001	5-Year Trend	13.72%

Adjusted Salvage & C/O/R	**13.72%**	**5.60%**	**8.12%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 397.2 - Communication Equipement (Mobile Radios)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	2,283.17	0.00	0.00%	75.37	3.30%	(75.37)	-3.30%
1993	(2,004.36)	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	3,643.25	0.00	0.00%	160.83	4.41%	(160.83)	-4.41%
1997	5,990.30	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 397.2 - Communication Equipement (Mobile Radios)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	2,283.17	0.00	0.00%	75.37	3.30%	(75.37)	-3.30%
1991-1993	278.81	0.00	0.00%	75.37	27.03%	(75.37)	-27.03%
1992-1994	278.81	0.00	0.00%	75.37	27.03%	(75.37)	-27.03%
1993-1995	(2,004.36)	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	3,643.25	0.00	0.00%	160.83	4.41%	(160.83)	-4.41%
1995-1997	9,633.55	0.00	0.00%	160.83	1.67%	(160.83)	-1.67%
1996-1998	9,633.55	0.00	0.00%	160.83	1.67%	(160.83)	-1.67%
1997-1999	5,990.30	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	9,912.36	0.00	0.00%	236.20	2.38%	(236.20)	-2.38%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	10
Avg Ret Age	11.9
Years to ASL	-1.9
Inflation Factor At 2.75% to ASL	0.95

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.00%
1987-2001	15-Year Trend	0.00%
1992-2001	10-Year Trend	0.00%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**2.26%**	**-2.26%**

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 397.3 - Telephone Communication Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	10,059.46	2,383.37	23.69%	1,303.39	12.96%	1,079.98	10.74%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	14,508.97	978.82	6.75%	1,178.98	8.13%	(200.16)	-1.38%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	2,398.72	0.00	0.00%	51.31	2.14%	(51.31)	-2.14%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	6,216.02	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	3,811.55	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	10,664.86	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	17,813.17	0.00	0.00%	106.00	0.60%	(106.00)	-0.60%
1996	2,875.52	0.00	0.00%	48.76	1.70%	(48.76)	-1.70%
1997	13,440.76	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	1,165.64	1,165.64	100.00%	0.00	0.00%	1,165.64	100.00%
1999	241.33	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	2,594.47	35.00	1.35%	0.00	0.00%	35.00	1.35%
2001	4,232.01	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 397.3 - Telephone Communication Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	10,059.46	2,383.37	23.69%	1,303.39	12.96%	1,079.98	10.74%
1976-1978	10,059.46	2,383.37	23.69%	1,303.39	12.96%	1,079.98	10.74%
1977-1979	10,059.46	2,383.37	23.69%	1,303.39	12.96%	1,079.98	10.74%
1978-1980	14,508.97	978.82	6.75%	1,178.98	8.13%	(200.16)	-1.38%
1979-1981	14,508.97	978.82	6.75%	1,178.98	8.13%	(200.16)	-1.38%
1980-1982	14,508.97	978.82	6.75%	1,178.98	8.13%	(200.16)	-1.38%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	2,398.72	0.00	0.00%	51.31	2.14%	(51.31)	-2.14%
1983-1985	2,398.72	0.00	0.00%	51.31	2.14%	(51.31)	-2.14%
1984-1986	2,398.72	0.00	0.00%	51.31	2.14%	(51.31)	-2.14%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	6,216.02	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	10,027.57	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	20,692.43	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	14,476.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	10,664.86	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	17,813.17	0.00	0.00%	106.00	0.60%	(106.00)	-0.60%
1994-1996	20,688.69	0.00	0.00%	154.76	0.75%	(154.76)	-0.75%
1995-1997	34,129.45	0.00	0.00%	154.76	0.45%	(154.76)	-0.45%
1996-1998	17,481.92	1,165.64	6.67%	48.76	0.28%	1,116.88	6.39%
1997-1999	14,847.73	1,165.64	7.85%	0.00	0.00%	1,165.64	7.85%
1998-2000	4,001.44	1,200.64	30.01%	0.00	0.00%	1,200.64	30.01%
1999-2001	7,067.81	35.00	0.50%	0.00	0.00%	35.00	0.50%
1968-2001	90,022.48	4,562.83	5.07%	2,688.44	2.99%	1,874.39	2.08%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	10
Avg Ret Age	14.2
Years to ASL	-4.2
Inflation Factor At 2.75% to ASL	0.89

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	7.29%
1987-2001	15-Year Trend	10.13%
1992-2001	10-Year Trend	13.63%
1997-2001	5-Year Trend	16.30%

Adjusted Salvage & C/O/R			**16.30%**	**2.66%**	**13.64%**
1985 Total	490.50	26,450.22			
LESS:					
Crookston	490.50	108.01			
WBI Sale		26,342.21			
Net Activity	0.00	0.00			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 397.5 - Supervisory & Telemetering Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	15,979.03	9,909.10	62.01%	282.07	1.77%	9,627.03	60.25%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	56,793.86	27,373.05	48.20%	391.66	0.69%	26,981.39	47.51%
1971	0.00	6,627.00	0.00%	0.00	0.00%	6,627.00	0.00%
1972	691.27	0.00	0.00%	22.14	3.20%	(22.14)	-3.20%
1973	4,242.79	0.00	0.00%	372.39	8.78%	(372.39)	-8.78%
1974	3,323.43	0.00	0.00%	307.32	9.25%	(307.32)	-9.25%
1975	1,598.56	0.00	0.00%	442.53	27.68%	(442.53)	-27.68%
1976	334.85	0.00	0.00%	11.05	3.30%	(11.05)	-3.30%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	24.97	0.00	0.00%	89.32	357.71%	(89.32)	-357.71%
1979	366.42	0.00	0.00%	47.36	12.93%	(47.36)	-12.93%
1980	8,367.60	0.00	0.00%	400.09	4.78%	(400.09)	-4.78%
1981	2,019.56	0.00	0.00%	94.14	4.66%	(94.14)	-4.66%
1982	4,690.02	0.00	0.00%	335.18	7.15%	(335.18)	-7.15%
1983	19,045.08	(12.00)	-0.06%	1,213.41	6.37%	(1,225.41)	-6.43%
1984	30,303.39	9,010.49	29.73%	340.42	1.12%	8,670.07	28.61%
1985	8,326.95	8,326.66	100.00%	0.00	0.00%	8,326.66	100.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	10,269.85	0.00	0.00%	165.68	1.61%	(165.68)	-1.61%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	6,529.14	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	43,825.12	0.00	0.00%	145.22	0.33%	(145.22)	-0.33%
1992	0.00	0.00	0.00%	507.54	0.00%	(507.54)	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 397.5 - Supervisory & Telemetering Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	72,772.89	37,282.15	51.23%	673.73	0.93%	36,608.42	50.31%
1969-1971	56,793.86	34,000.05	59.87%	391.66	0.69%	33,608.39	59.18%
1970-1972	57,485.13	34,000.05	59.15%	413.80	0.72%	33,586.25	58.43%
1971-1973	4,934.06	6,627.00	134.31%	394.53	8.00%	6,232.47	126.32%
1972-1974	8,257.49	0.00	0.00%	701.85	8.50%	(701.85)	-8.50%
1973-1975	9,164.78	0.00	0.00%	1,122.24	12.25%	(1,122.24)	-12.25%
1974-1976	5,256.84	0.00	0.00%	760.90	14.47%	(760.90)	-14.47%
1975-1977	1,933.41	0.00	0.00%	453.58	23.46%	(453.58)	-23.46%
1976-1978	359.82	0.00	0.00%	100.37	27.89%	(100.37)	-27.89%
1977-1979	391.39	0.00	0.00%	136.68	34.92%	(136.68)	-34.92%
1978-1980	8,758.99	0.00	0.00%	536.77	6.13%	(536.77)	-6.13%
1979-1981	10,753.58	0.00	0.00%	541.59	5.04%	(541.59)	-5.04%
1980-1982	15,077.18	0.00	0.00%	829.41	5.50%	(829.41)	-5.50%
1981-1983	25,754.66	(12.00)	-0.05%	1,642.73	6.38%	(1,654.73)	-6.42%
1982-1984	54,038.49	8,998.49	16.65%	1,889.01	3.50%	7,109.48	13.16%
1983-1985	57,675.42	17,325.15	30.04%	1,553.83	2.69%	15,771.32	27.34%
1984-1986	38,630.34	17,337.15	44.88%	340.42	0.88%	16,996.73	44.00%
1985-1987	8,326.95	8,326.66	100.00%	0.00	0.00%	8,326.66	100.00%
1986-1988	10,269.85	0.00	0.00%	165.68	1.61%	(165.68)	-1.61%
1987-1989	10,269.85	0.00	0.00%	165.68	1.61%	(165.68)	-1.61%
1988-1990	16,798.99	0.00	0.00%	165.68	0.99%	(165.68)	-0.99%
1989-1991	50,354.26	0.00	0.00%	145.22	0.29%	(145.22)	-0.29%
1990-1992	50,354.26	0.00	0.00%	652.76	1.30%	(652.76)	-1.30%
1991-1993	43,825.12	0.00	0.00%	652.76	1.49%	(652.76)	-1.49%
1992-1994	0.00	0.00	0.00%	507.54	0.00%	(507.54)	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	216,731.89	61,234.30	28.25%	5,167.52	2.38%	56,066.78	25.87%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	10
Avg Ret Age	0
Years to ASL	10
Inflation Factor At 2.75% to ASL	1.31

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	-6.48%
1987-2001	15-Year Trend	-13.33%
1992-2001	10-Year Trend	0.00%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R			**0.00%**	**3.13%**	**-3.13%**
1985 Total	8,479.55	420,315.14			
LESS:					
Crookston	152.60	32.50			
WBI Sale		411,955.98			
Net Activity	8,326.95	8,326.66			

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 398 - Miscellaneous Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	263.02	531.61	202.12%	0.00	0.00%	531.61	202.12%
1969			0.00%	0.00	0.00%	0.00	0.00%
1970	413.11	259.64	62.85%	0.00	0.00%	259.64	62.85%
1971	360.39	45.32	12.58%	0.00	0.00%	45.32	12.58%
1972	485.00	170.00	35.05%	73.60	15.18%	96.40	19.88%
1973	1,727.57	333.00	19.28%	0.00	0.00%	333.00	19.28%
1974	1,681.31	810.00	48.18%	0.00	0.00%	810.00	48.18%
1975	349.27	330.00	94.48%	0.00	0.00%	330.00	94.48%
1976	814.22	636.00	78.11%	0.00	0.00%	636.00	78.11%
1977	2,961.87	1,262.66	42.63%	0.00	0.00%	1,262.66	42.63%
1978	1,265.26	873.00	69.00%	0.00	0.00%	873.00	69.00%
1979	1,824.13	825.35	45.25%	0.00	0.00%	825.35	45.25%
1980	1,758.69	1,358.00	77.22%	0.00	0.00%	1,358.00	77.22%
1981	5,454.37	1,670.25	30.62%	(27.47)	-0.50%	1,697.72	31.13%
1982			0.00%	0.00	0.00%	0.00	0.00%
1983	382.20	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	512.44	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	996.42	298.88	30.00%	0.00	0.00%	298.88	30.00%
1986	348.92	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	717.04	75.00	10.46%	0.00	0.00%	75.00	10.46%
1988	582.73	363.00	62.29%	0.00	0.00%	363.00	62.29%
1989			0.00%	0.00	0.00%	0.00	0.00%
1990	324.63	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	1,084.17	158.17	14.59%	0.00	0.00%	158.17	14.59%
1992			0.00%	0.00	0.00%	0.00	0.00%
1993		75.00	0.00%	0.00	0.00%	75.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	2,045.04	574.99	28.12%	0.00	0.00%	574.99	28.12%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	3,251.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	2,743.46	40.00	1.46%	0.00	0.00%	40.00	1.46%

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 398 - Miscellaneous Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	676.13	791.25	117.03%	0.00	0.00%	791.25	117.03%
1969-1971	773.50	304.96	39.43%	0.00	0.00%	304.96	39.43%
1970-1972	1,258.50	474.96	37.74%	73.60	5.85%	401.36	31.89%
1971-1973	2,572.96	548.32	21.31%	73.60	2.86%	474.72	18.45%
1972-1974	3,893.88	1,313.00	33.72%	73.60	1.89%	1,239.40	31.83%
1973-1975	3,758.15	1,473.00	39.19%	0.00	0.00%	1,473.00	39.19%
1974-1976	2,844.80	1,776.00	62.43%	0.00	0.00%	1,776.00	62.43%
1975-1977	4,125.36	2,228.66	54.02%	0.00	0.00%	2,228.66	54.02%
1976-1978	5,041.35	2,771.66	54.98%	0.00	0.00%	2,771.66	54.98%
1977-1979	6,051.26	2,961.01	48.93%	0.00	0.00%	2,961.01	48.93%
1978-1980	4,848.08	3,056.35	63.04%	0.00	0.00%	3,056.35	63.04%
1979-1981	9,037.19	3,853.60	42.64%	(27.47)	-0.30%	3,881.07	42.95%
1980-1982	7,213.06	3,028.25	41.98%	(27.47)	-0.38%	3,055.72	42.36%
1981-1983	5,836.57	1,670.25	28.62%	(27.47)	-0.47%	1,697.72	29.09%
1982-1984	894.64	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	1,891.06	298.88	15.80%	0.00	0.00%	298.88	15.80%
1984-1986	1,857.78	298.88	16.09%	0.00	0.00%	298.88	16.09%
1985-1987	2,062.38	373.88	18.13%	0.00	0.00%	373.88	18.13%
1986-1988	1,648.69	438.00	26.57%	0.00	0.00%	438.00	26.57%
1987-1989	1,299.77	438.00	33.70%	0.00	0.00%	438.00	33.70%
1988-1990	907.36	363.00	40.01%	0.00	0.00%	363.00	40.01%
1989-1991	1,408.80	158.17	11.23%	0.00	0.00%	158.17	11.23%
1990-1992	1,408.80	158.17	11.23%	0.00	0.00%	158.17	11.23%
1991-1993	1,084.17	233.17	21.51%	0.00	0.00%	233.17	21.51%
1992-1994	0.00	75.00	0.00%	0.00	0.00%	75.00	0.00%
1993-1995	0.00	75.00	0.00%	0.00	0.00%	75.00	0.00%
1994-1996	2,045.04	574.99	28.12%	0.00	0.00%	574.99	28.12%
1995-1997	2,045.04	574.99	28.12%	0.00	0.00%	574.99	28.12%
1996-1998	2,045.04	574.99	28.12%	0.00	0.00%	574.99	28.12%
1997-1999	3,251.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	3,251.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	5,995.40	40.00	0.67%	0.00	0.00%	40.00	0.67%
1968-2001	32,347.20	10,689.87	33.05%	46.13	0.14%	10,643.74	32.90%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	10
Avg Ret Age	9.7
Years to ASL	0.3
Inflation Factor At 2.75% to ASL	1.01

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	7.24%
1987-2001	15-Year Trend	4.07%
1992-2001	10-Year Trend	6.40%
1997-2001	5-Year Trend	-13.52%

Adjusted Salvage & C/O/R			**-13.52%**	**0.14%**	**-13.67%**
1985 Total	2,219.99	12,151.03			
LESS:					
Crookston	1,223.57	724.52			
WBI Sale		11,127.63			
Net Activity	996.42	298.88			

Earl M. Robinson, CDP
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January 27, 2003

Mr. Paul Bienek
Montana-Dakota Utilities Company
400 North Fourth Street
Bismark, ND 58501

Dear Mr. Bienek:

In accordance with your authorization, we have prepared a depreciation study related to the utility plant in service of Montana-Dakota Utilities Company - Common Plant as of December 31, 2001. Our findings and recommendations, together with supporting schedules and exhibits, are set forth in the accompanying report.

Summary schedules have been prepared to illustrate the impact of instituting the recommended annual depreciation rates as a basis for the Company's annual depreciation expense as compared to the rates presently utilized. The application of the present rates to the depreciable plant in service as of December 31, 2001 results in an annual depreciation expense of $2,167,043. In comparison, the application of the proposed depreciation rates to the depreciable plant in service at December 31, 2001 results in an annual depreciation expense of $ 2,666,460, which is a increase of $499,417 from current rates. The composite annual depreciation rate under present rates is 5.84 percent, while the proposed proforma composite depreciation rate is 7.18 percent.

Section 2 of our report contains the summary schedules showing the results of our service life and salvage studies and summaries of presently utilized depreciation rates. The subsequent sections of the report present a detailed outline of the methodology and procedures used in the study together with supporting calculations and analyses used in the development of the results. A detailed table of contents follows this letter.

Respectfully submitted,

Earl M Robinson

EARL M. ROBINSON, CDP

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MONTANA-DAKOTA UTILITIES COMPANY
Common Plant

Executive Summary

Table 1 on page 2-1 is a comparative summary which illustrates the effect of instituting the revised depreciation rates. The schedule includes a comparison of the annual depreciation rates and annual depreciation expense under both present and proposed rates applied using the Straight Line Method for each depreciable property group of the Montana-Dakota Utilities Company-Common Plant (the "Company") plant in service as of December 31, 2001. Both the present and proposed depreciation rates were developed utilizing the Straight Line (SL) Method, Broad Group (BG), Procedure and the Average Remaining Life (ARL) Technique.

Table 2 on pages 2-2 to 2-3 provides a summary of the detailed life estimates and service life parameters (Iowa Curves) utilized in preparing the Average Remaining Life depreciation rates for each property group. The schedule provides a summary of the detailed data and narrative of the study results set forth in Sections 4 through 7. The developed depreciation rates (Column L) were determined by studying the Company's historical investment data together with the interpretation of future life expectancies which will have a bearing on the overall service life of the Company's property.

Table 3 on page 2-4 is a summary schedule showing the impact on the Company's annual depreciation expense as a result of estimating current average service lives for the applicable general plant accounts as well as changing from depreciating the property groups to a straight line amortization of the investment over a set period of years.

The various schedules comprising Table 4 on pages 2-5 to 2-17 summarize the

development of the annual amortization amounts for each of the general plant accounts for which the depreciation amortization approach is being proposed. The proposal to amortize the investments within the selected general plant accounts is driven by the Company's ongoing difficulty to effectively track various of the property account investments that are in many cases related to a large quantity of items of corresponding small investment amounts. Due to the inability to effectively track the items, many times the items are no longer utilized but remain on the company's books and records as unrecorded retirements. Therefore to simplify the accounting procedure for these property items it is proposed that the investments within each vintage of the applicable property group be amortized over a predetermined time period. Once attaining the stated amortization period age the asset's original cost investment will have been fully amortized, and accordingly, will be retired from the company's books and records. The property accounts for which asset investment amortization is being proposed includes Account 391, 393, 394, 395, 397, and 398.

In the process of moving from depreciation to amortization of the selected general plant accounts, there are, by the very nature of average service life dispersion, vintage investments within the applicable property groups which exceeds the estimated average service life / proposed amortization period. Given that each vintage of property will be amortized over the average service life, an adjustment needs to be incorporated into the change-over process to recover the under depreciated portion of the older investments. Accordingly, the variance between the amortization starting-point depreciation reserve and the Company's actual book reserve (either positive or negative) is being recorded on a straight line basis over the proposed amortization period along with the annual amortization

of all other vintage investments. The amortization starting point book depreciation reserve is equal to the sum of the original cost for vintages older than the amortization period plus the calculated deprecation reserve for vintages with ages equal to or less than the amortization period .

The utilization of the recommended depreciation rates based upon the Straight Line Average Remaining Life Procedure results in the setting of depreciation rates which will continuously true up the Company's level of capital recovery over the life of each asset group. Application of this procedure, which is based upon the current best estimates of service life together with the Company's plant in service and accrued depreciation, produces annual depreciation rates that will result in the Company recovering 100 percent of its investment -- no more, no less.

It is recommended that the Company continue to apply depreciation rates and maintain its book depreciation reserve on an account-level basis. The maintenance of the book reserve on an account-level basis requires both the development of annual depreciation expense and distribution of other reserve account charges to an individual level. Maintaining the Company's depreciation records in this detail will aid in completing the various rate studies and, most importantly, clearly identifies the Company's level of capital recovery relative to each category of plant investment.

The general drivers for the proposed depreciation rates include an assessment of the Company's historical experience with regard to achieved service lives and net salvage factors. In addition, consideration is given to current and anticipated events which are anticipated to impact the Company's ability to recover its fixed capital costs related to utility plant in service utilized to provide service to the Company's customers.

The depreciation rate for each individual account changed as a result of reflecting estimates obtained through the in-depth analysis of the Company's most recent data together with an interpretation of ongoing and anticipated future events. Some of the revisions were not significant and typically reflect fine tuning of previously utilized depreciation rates while others were more substantial in nature. Several of the accounts did reflect more significant changes (as outlined in Section 4 of this report) from the previously utilized depreciation rates.

The most notable depreciation/amortization occurred relative to Account 367 - Transmission Mains, Account 390 - General Structures, Account 391.1 - Office Furniture and Equipment, Account 391.5 - Computer Equipment - Other and Account 392 - Transportation Equipment - Cars & Trucks.

The depreciation rate for Account 391.1 - Office Furniture and Equipment increased from 1.48 percent to 4.95 percent. The proposed depreciation rate is the product of the application of applicable service life and net salvage factor for the property account. The proposed amortization rate is more in keeping with the typical depreciation rate for this property group.

The depreciation rate relative to Account 392 - Transportation Equipment - Cars & Trucks increased from 5.74 percent to 13.33 percent. This depreciation expense increase is the product of recognizing and incorporating a more appropriate level of average service life and net salvage factor that the Company will incur relative to this property class throughout its useful service life.

Conversely, the proposed depreciation/amortization rates declined for several accounts, the most notable fo which was Account 390- Structures.

The composite depreciation rate for Account 390 - Structures decreased from 3.76 percent to 2.93 percent. The decrease of the deprecation rate for this property group is the product of the application of the estimated average service and incorporation of the current book depreciation reserve.

The annual depreciation/amortization rate relative to Account 391.5 - Computer Equipment - Other declined from 26.51 percent to 0.46 percent.

Various of the remaining account/sub-accounts experienced increases and/or declines in recommended depreciation rates to a lesser degree, as noted per Table 1 of this report. This revision in annual depreciation rates and expense is the result of both changes in the estimated service lives and salvage factors, and reflects the impact of the Company's property changes since the most recent study.

With regard to the inclusion of higher negative net salvage levels in the development of proposed depreciation rates, as noted within my discussion related to net salvage both in Section 3 of the depreciation report and my testimony, I have highlighted the fact that the level of experienced net salvage should simply be a benchmark from which to estimate future net salvage. It is highly likely that the negative net salvage amounts experienced even recently will simply be the floor above which future negative net salvage levels will increase to a higher level. To appropriately and proportionately allocate the true total asset cost (original cost adjusted for net salvage) over its applicable service life, proper consideration must be given in each accounting period, to the total costs that are anticipated to occur relative to the Company's assets that provide customer service.

Applying the proposed depreciation rates to the Company's December 31, 2001 plant in service produces annual depreciation/amortization expense of $2,666,460 which is a

increase of $499,417 from current depreciation rates.

The following summary compares the present and proposed composite depreciation rates for illustrative purposes only. The Composite Depreciation Rate should not be applied to the total Company investment inasmuch as the non-proportional change in plant investment as a result of property additions or retirements would render the composite rate inappropriate. The Table 1 schedule lists the recommended annual depreciation rates for each property account.

Present Depreciation Rates

Depreciable Plant In Service at December 31, 2001	$37,131,010
Annual Depreciation Expense	2,167,043
Composite Annual Depreciation Rate	5.84%

Proforma Proposed Depreciation Rates

Depreciable Plant In Service at December 31, 2001	$37,131,010
Annual Depreciation Expense	2,666,460
Composite Annual Depreciation Rate	7.18%

Montana-Dakota Utilities Company
Common Plant

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	General Plant						
390.0	General Structures	18,048,459.30	3.76%	678,622.07	2.93%	528,819.86	-149,802.21
	OFFICE FURNITURE & EQUIPMENT						
391.1	Office Furniture & Equipment	3,716,416.91	1.48%	55,002.97	4.95%	184,032.14	129,029.17
391.2	Computer Equipment - Honeywell	93,392.30	14.17%	13,233.69	1.52%	1,416.58	-11,817.11
391.3	Computer Equipment - PC	4,212,743.17	12.50%	526,592.90	23.29%	981,147.88	454,554.98
391.5	Computer Equipment - Other	820,399.57	26.51%	217,487.93	0.46%	3,797.58	-213,690.35
	TOTAL Account 391	8,842,951.95	9.19%	812,317.49	13.24%	1,170,394.18	358,076.69
	TRANSPORTATION EQUIPMENT						
392.1	Transportation Equipment (Trailers)	251,165.84	5.74%	14,416.92	0.00%	0.00	-14,416.92
392.2	Transportation Equipment (Cars & Trucks)	4,429,701.58	5.74%	254,264.87	13.33%	590,479.22	336,214.35
	TOTAL Account 392	4,680,867.42	5.74%	268,681.79	12.61%	590,479.22	321,797.43
393.0	Stores Equipment	47,385.55	3.36%	1,592.15	2.80%	1,327.61	-264.54
	TOOLS, SHOP & GARAGE EQ.						
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026.00	3.44%	8,084.89	6.11%	14,362.50	6,277.61
394.3	Vehicle Maintenance Equipment	102,746.14	4.46%	4,582.48	4.75%	4,877.05	294.57
394.4	Vehicle Refueling Equipment	838,830.77	8.42%	70,629.55	4.38%	36,709.31	-33,920.24
	TOTAL Account 394	1,176,602.91	7.08%	83,296.92	4.76%	55,948.86	-27,348.06
396.2	Power Operated Equipment	157,572.62	4.83%	7,610.76	2.69%	4,238.70	-3,372.06
	COMMUNICATION EQUIPMENT						
397.1	Radio Communication Equip. (Fixed)	646,187.02	4.33%	27,979.90	4.99%	32,241.83	4,261.93
397.2	Radio Communication Equip. (Mobile)	1,285,023.00	6.68%	85,839.54	4.08%	52,474.26	-33,365.28
397.3	General Telephone Communication Equip.	779,821.23	10.62%	82,817.01	8.72%	68,036.36	-14,780.65
397.5	Supervisory & Telemetering Equip.	48,295.94	0.59%	284.95	0.35%	170.00	-114.95
397.8	Network Equipment	824,948.21	12.50%	103,118.53	17.95%	148,037.04	44,918.51
	TOTAL Account 397	3,584,275.40	8.37%	300,039.93	8.40%	300,959.49	919.56
398.0	Miscellaneous Equipment	592,894.94	2.51%	14,881.66	2.41%	14,291.82	-589.84
	Sub-Total (General Plant) Amortization	**10,031,367.58**	**6.83%**	**685,535.25**	**5.60%**	**561,774.08**	**-123,761.17**
	TOTAL General Plant	37,131,010.09	5.84%	2,167,042.77	7.18%	2,666,459.74	499,416.97
	TOTAL Depreciable Plant	37,131,010.09	5.84%	2,167,042.77	7.18%	2,666,459.74	499,416.97
	Amortizable Plant						
392.3	Aircraft Equipment	1,024,349.51					
	TOTAL Amortizable Plant	1,024,349.51					
	NON-DEPRECIABLE PLANT						
389.0	Land & Land Rights (General)	1,547,408.83					
	Total Land	1,547,408.83					
	INTANGIBLE PLANT						
303.0	Miscellaneous Intangible Plant	13,553,859.20					
	Total Intangible Plant	13,553,859.20					
	TOTAL Non-Depreciable Plant	15,101,268.03					
	TOTAL Plant in Service	53,256,627.63					

Table 2

Montana-Dakota Utilities Company
Common Plant

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	General Plant										
390.0	General Structures	18,048,459.30	-10%	-1,804,845.93	19,853,305.23	8,706,838.27	11,146,466.96	35-R3	21.1	528,268.58	2.93%
	OFFICE FURNITURE & EQUIPMENT										
391.1	Office Furniture & Equipment	3,716,416.91	5%	185,820.85	3,530,596.06	1,911,562.38	1,619,033.68 (1)	15-R3	N/A	184,032.14	4.95%
391.2	Computer Equipment - Honeywell	93,392.30	0%	0.00	93,392.30	99,578.89	-6,186.59 (1)	7-R1	N/A	1,416.58	1.52%
391.3	Computer Equipment - PC	4,212,743.17	0%	0.00	4,212,743.17	1,759,815.80	2,452,927.37 (1)	5-R3	2.5	981,170.95	23.29%
391.5	Computer Equipment - Other	820,399.57	0%	0.00	820,399.57	821,580.87	-1,181.30 (1)	11-R3	N/A	3,797.58	0.46%
	TOTAL Account 391	8,842,951.95		185,820.85	8,657,131.10	4,592,537.94	4,064,593.16			1,170,417.24	13.24%
	TRANSPORTATION EQUIPMENT										
392.1	Transportation Equipment (Trailers)	251,165.84	15%	37,674.88	213,490.96	251,165.83	-37,674.87	20-L2	10.8	0.00	0.00% (2)
392.2	Transportation Equipment (Cars & Trucks)	4,429,701.58	20%	885,940.32	3,543,761.26	1,477,128.20	2,066,633.06	7-R3	3.5	590,466.59	13.33%
	TOTAL Account 392	4,680,867.42		923,615.20	3,757,252.22	1,728,294.03	2,028,958.19			590,466.59	12.61%
393.0	Stores Equipment	47,385.55	0%	0.00	47,385.55	14,487.18	32,898.37 (1)	30-R2	N/A	1,327.61	2.80%
	TOOLS, SHOP & GARAGE EQ.										
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026.00	0%	0.00	235,026.00	36,457.89	198,568.11 (1)	18-R2	N/A	14,362.50	6.11%
394.3	Vehicle Maintenance Equipment	102,746.14	0%	0.00	102,746.14	39,144.35	63,601.79 (1)	18-R3	N/A	4,877.05	4.75%
394.4	Vehicle Refueling Equipment	838,830.77	0%	0.00	838,830.77	561,054.56	277,776.21 (1)	20-R3	N/A	36,709.31	4.38%
	TOTAL Account 394	1,176,602.91		0.00	1,176,602.91	636,656.80	539,946.11			55,948.86	4.76%
396.2	Power Operated Equipment	157,572.62	40%	63,029.05	94,543.57	58,932.03	35,611.54	10-R2	8.4	4,239.47	2.69%
	COMMUNICATION EQUIPMENT										
397.1	Radio Communication Equip. (Fixed)	646,187.02	-10%	-64,618.70	710,805.72	409,277.55	301,528.17 (1)	15-R3	N/A	32,241.83	4.99%
397.2	Radio Communication Equip. (Mobile)	1,285,023.00	0%	0.00	1,285,023.00	1,034,021.53	251,001.47 (1)	15-R3	N/A	52,474.26	4.08%
397.3	General Telephone Communication Equip.	779,821.23	10%	77,982.12	701,839.11	419,620.16	282,218.95 (1)	10-R2	N/A	68,036.36	8.72%
397.5	Supervisory & Telemetering Equip.	48,295.94	0%	0.00	48,295.94	46,185.03	2,110.91 (1)	15-L1	N/A	170.00	0.35%
397.8	Network Equipment	824,948.21	0%	0.00	824,948.21	330,668.70	494,279.51 (1)	5-R3	N/A	148,037.04	17.95%
	TOTAL Account 397	3,584,275.40		13,363.42	3,570,911.98	2,239,772.97	1,331,139.01			300,959.49	8.40%
398.0	Miscellaneous Equipment	592,894.94	5%	29,644.75	563,250.19	372,786.90	190,463.29 (1)	20-R2	N/A	14,291.82	2.41%
	TOTAL General Plant	37,131,010.09		-589,372.66	37,720,382.75	18,350,306.12	19,370,076.63			2,665,919.65	7.18%
	TOTAL Depreciable Plant	37,131,010.09		-589,372.66	37,720,382.75	18,350,306.12	19,370,076.63			2,665,919.65	7.18%

Montana-Dakota Utilities Company
Common Plant

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	Amortizable Plant										
392.3	Aircraft Equipment	1,024,349.51				282,079.59					
	TOTAL Amortizable Plant	1,024,349.51				282,079.59					
	NON-DEPRECIABLE PLANT										
389.0	Land & Land Rights (General)	1,547,408.83				0.00					
	Total Land	1,547,408.83				0.00					
	INTANGIBLE PLANT										
303.0	Miscellaneous Intangible Plant	13,553,859.20				5,006,700.27					
	Total Intangible Plant	13,553,859.20				5,006,700.27					
	TOTAL Non-Depreciable Plant	15,101,268.03				5,006,700.27					
	TOTAL Plant in Service	53,256,627.63				23,639,085.98					

(1) Implicit Depreciation Rates and Annual Accrual Based Upon General Plant Amortization Calculation
(2) Account Fully Depreciated. See Narrative In Section 4.

Table 3

Montana-Dakota Utilities Company
Common Plant

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation/Amortization Expense
Under Present Rates and Proposed Amortization

Account No. (a)	Description (b)	Original Cost 12/31/2001 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Amortization Rate % (f)	Proposed Amortization Annual Accrual (g)	Net Change Depr/Amort Expense (h)
	DEPRECIABLE GENERAL PLANT						
	OFFICE FURNITURE & EQUIPMENT						
391.1	Office Furniture & Equipment	3,716,416.91	1.48%	55,002.97	4.95%	184,032.14	129,029.17
391.2	Computer Equipment - Honeywell	93,392.30	14.17%	13,233.69	1.52%	1,416.58	-11,817.11
391.5	Computer Equipment - Other	820,399.57	26.51%	217,487.93	0.46%	3,797.58	-213,690.35
	TOTAL Account 391	4,630,208.78	6.17%	285,724.59	4.09%	189,246.30	-96,478.29
393	Stores Equipment	47,385.55	3.36%	1,592.15	2.80%	1,327.61	-264.54
	TOOLS, SHOP & GARAGE EQ.						
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026.00	3.44%	8,084.89	6.11%	14,362.50	6,277.61
394.3	Vehicle Maintenance Equipment	102,746.14	4.46%	4,582.48	4.75%	4,877.05	294.57
394.4	Vehicle Refueling Equipment	838,830.77	8.42%	70,629.55	4.38%	36,709.31	-33,920.24
	TOTAL Account 394	1,176,602.91	7.08%	83,296.92	4.76%	55,948.86	-27,348.06
	COMMUNICATION EQUIPMENT						
397.1	Radio Communication Equip. (Fixed)	646,187.02	4.33%	27,979.90	4.99%	32,241.83	4,261.93
397.2	Radio Communication Equip. (Mobile)	1,285,023.00	6.68%	85,839.54	4.08%	52,474.26	-33,365.28
397.3	General Telephone Communication Equip.	779,821.23	10.62%	82,817.01	8.72%	68,036.36	-14,780.65
397.5	Supervisory & Telemetering Equip.	48,295.94	0.59%	284.95	0.35%	170.00	-114.95
397.8	Network Equipment	824,948.21	12.50%	103,118.53	17.95%	148,037.04	44,918.51
	TOTAL Account 397	3,584,275.40	8.37%	300,039.93	8.40%	300,959.49	919.56
398	Miscellaneous Equipment	592,894.94	2.51%	14,881.66	2.41%	14,291.82	-589.84
	Sub-Total (General Plant) Amortization	**10,031,367.58**	6.83%	**685,535.25**	5.60%	**561,774.08**	**-123,761.17**

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 391.10 - Office Furniture & Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1960	1.50	1	(1)	1.50	0.00	0	0.00
1961	19.09	18	(1)	19.09	0.00	0	0.00
1962	75.13	71	(1)	75.13	0.00	0	0.00
1963	292.85	278	(1)	292.85	0.00	0	0.00
1964	651.45	619	(1)	651.45	0.00	0	0.00
1965	1,016.06	965	(1)	1,016.06	0.00	0	0.00
1966	3,458.20	3,285	(1)	3,458.20	0.00	0	0.00
1967	1,938.70	1,842	(1)	1,938.70	0.00	0	0.00
1968	17,011.43	16,161	(1)	17,011.43	0.00	0	0.00
1969	7,725.44	7,339	(1)	7,725.44	0.00	0	0.00
1970	5,866.63	5,573	(1)	5,866.63	0.00	0	0.00
1971	8,698.41	8,263	(1)	8,698.41	0.00	0	0.00
1972	20,989.14	19,944	(1)	20,989.14	0.00	0	0.00
1973	17,250.80	16,388	(1)	17,250.80	0.00	0	0.00
1974	28,368.26	26,950	(1)	28,368.26	0.00	0	0.00
1975	9,446.11	8,974	(1)	9,446.11	0.00	0	0.00
1976	25,929.59	24,633	(1)	25,929.59	0.00	0	0.00
1977	148,440.80	136,318	(1)	148,440.80	0.00	0	0.00
1978	253,109.68	231,094	(1)	253,109.68	0.00	0	0.00
1979	168,472.49	151,779	(1)	168,472.49	0.00	0	0.00
1980	50,274.04	44,554	(1)	50,274.04	0.00	0	0.00
1981	100,112.42	87,162	(1)	100,112.42	0.00	0	0.00
1982	150,081.96	128,301	(1)	150,081.96	0.00	0	0.00
1983	203,368.20	170,419	(1)	203,368.20	0.00	0	0.00
1984	159,200.56	130,390	(1)	159,200.56	0.00	0	0.00
1985	275,028.67	219,252	(1)	275,028.67	0.00	0	0.00
1986	99,374.85	76,686	(1)	99,374.85	0.00	0	0.00
1987	55,263.63	41,017	(2)	41,017.00	14,246.63	1	14,246.63
1988	47,143.87	33,407	(2)	33,407.00	13,736.87	2	6,868.44
1989	42,984.46	28,851	(2)	28,851.00	14,133.46	3	4,711.15
1990	204,173.35	128,693	(2)	128,693.00	75,480.35	4	18,870.09
1991	76,877.12	45,071	(2)	45,071.00	31,806.12	5	6,361.22
1992	50,233.30	27,102	(2)	27,102.00	23,131.30	6	3,855.22
1993	109,964.67	53,920	(2)	53,920.00	56,044.67	7	8,006.38
1994	96,732.58	42,453	(2)	42,453.00	54,279.58	8	6,784.95
1995	76,776.57	29,584	(2)	29,584.00	47,192.57	9	5,243.62
1996	108,369.02	35,749	(2)	35,749.00	72,620.02	10	7,262.00
1997	234,174.95	63,853	(2)	63,853.00	170,321.95	11	15,483.81
1998	108,233.34	23,157	(2)	23,157.00	85,076.34	12	7,089.70
1999	194,687.24	29,976	(2)	29,976.00	164,711.24	13	12,670.10
2000	256,353.83	23,826	(2)	23,826.00	232,527.83	14	16,609.13
2001	298,246.52	9,285	(2)	9,285.00	288,961.52	15	19,264.10
	3,716,416.91	2,133,203		2,372,146.46	1,344,270.45	4.13%	153,326.53
Book Reserve				1,911,562.38			
Starting Point Depreciation Reserve				2,372,146.46			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				460,584.08	460,584.08	15	30,705.61
Total Amortization Amount						4.95%	184,032.14

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 391.20 - Computer Equipment - Honeywell

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 7
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1986	159.20	159	(1)	159.20	0.00	0	0.00
1987	939.23	939	(1)	939.23	0.00	0	0.00
1988	642.03	596	(1)	642.03	0.00	0	0.00
1989	18,685.68	17,013	(1)	18,685.68	0.00	0	0.00
1990	18,073.93	15,797	(1)	18,073.93	0.00	0	0.00
1991	12,386.05	10,290	(1)	12,386.05	0.00	0	0.00
1992	5,761.78	4,502	(1)	5,761.78	0.00	0	0.00
1993	1,742.77	1,265	(1)	1,742.77	0.00	0	0.00
1994	20,126.70	13,365	(1)	20,126.70	0.00	0	0.00
1995	212.98	127	(2)	127.00	85.98	1	85.98
1996	10,154.40	5,274	(2)	5,274.00	4,880.40	2	2,440.20
1997	4,499.50	1,963	(2)	1,963.00	2,536.50	3	845.50
1998	8.03	3	(2)	3.00	5.03	4	1.26
1999	0.00	0	(2)	0.00	0.00	5	0.00
2000	0.00	0	(2)	0.00	0.00	6	0.00
2001	0.00	0	(2)	0.00	0.00	7	0.00
	93,392.28	71,293		85,884.37	7,507.91	3.61%	3,372.94
Book Rese				99,578.89			
Starting Point Depreciation Reserve				85,884.37			
Book/Amortization Starting Point Depr Reserve Varian				-13,694.52	-13,694.52	7	-1,956.36
(Amortize over Amortization Period)							
Total Amortization Amount						1.52%	1,416.58

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 391.50 - Computer Equipment - Other

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 5
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs	Annual Amortization Amount
1991	268,804.48	268,804	(1)	268,804.48	0.00	0	0.00
1992	221,442.66	221,443	(1)	221,442.66	0.00	0	0.00
1993	0.00	0	(1)	0.00	0.00	0	0.00
1994	669.20	602	(1)	669.20	0.00	0	0.00
1995	246,056.34	215,865	(1)	246,056.34	0.00	0	0.00
1996	21,913.91	18,131	(1)	21,913.91	0.00	0	0.00
1997	11,134.81	8,249	(2)	8,249.00	2,885.81	1	2,885.81
1998	0.00	0	(2)	0.00	0.00	2	0.00
1999	0.00	0	(2)	0.00	0.00	3	0.00
2000	48,373.78	13,870	(2)	13,870.00	34,503.78	4	8,625.95
2001	2,004.39	196	(2)	196.00	1,808.39	5	361.68
	820,399.57	747,160		781,201.59	39,197.98	1.45%	11,873.43
Book Reserve				821,580.87			
Starting Point Depreciation Reserve				781,201.59			
Book/Amortization Starting Point Depr Reserve Variance				-40,379.28	-40,379.28	5	-8,075.86
(Amortize over Amortization Period)							
Total Amortization Amount						0.46%	3,797.58

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 393- Stores Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 30
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1993	1,925.33	473	(2)	473.00	1,452.33	**22**	66.02
1994	0	0	(2)	0.00	0.00	**23**	0.00
1995	16,301.46	3,100	(2)	3,100.00	13,201.46	**24**	550.06
1996	3,495.87	566	(2)	566.00	2,929.87	**25**	117.19
1997	18,728.58	2,492	(2)	2,492.00	16,236.58	**26**	624.48
1998	175.14	18	(2)	18.00	157.14	**27**	5.82
1999	0.00	0	(2)	0.00	0.00	**28**	0.00
2000	0	0	(2)	0.00	0.00	**29**	0.00
2001	6,759.17	102	(2)	102.00	6,657.17	**30**	221.91
	47,385.55	6,751		6,751.00	40,634.55	3.35%	1,585.48
Book Reserve				14,487.18			
Starting Point Depreciation Reserve				6,751.00			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-7,736.18	-7,736.18	30	-257.87
Total Amortization Amount						2.80%	1,327.61

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 394.1 - Tools, Shop & Garage Equipment (Non-Unitized)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 18
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1992	12,561.33	5,474	(2)	5,474.00	7,087.33	9	787.48
1993	4,687.63	1,850	(2)	1,850.00	2,837.63	10	283.76
1994	78,684.31	27,721	(2)	27,721.00	50,963.31	11	4,633.03
1995	560.01	173	(2)	173.00	387.01	12	32.25
1996	13,482.62	3,559	(2)	3,559.00	9,923.62	13	763.36
1997	17,077.88	3,725	(2)	3,725.00	13,352.88	14	953.78
1998	45,406.59	7,776	(2)	7,776.00	37,630.59	15	2,508.71
1999	18,449.52	2,277	(2)	2,277.00	16,172.52	16	1,010.78
2000	14,608.41	1,091	(2)	1,091.00	13,517.41	17	795.14
2001	29,507.70	741	(2)	741.00	28,766.70	18	1,598.15
	235,026.00	54,387		54,387.00	180,639.00	5.69%	13,366.44
Book Reserve				36,457.89			
Starting Point Depreciation Reserve				54,387.00			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				17,929.11	17,929.11	18	996.06
Total Amortization Amount						6.11%	14,362.50

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 394.3 - Vehicle Maintainence Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	lemainin nortizati riod (Yea	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1988	369.59	221	(2)	221.00	148.59	7	7	21.23
1989	760.65	427	(2)	427.00	333.65	8	8	41.71
1991	32,309.61	15,594	(2)	15,594.00	16,715.61	10	10	1,671.56
1992	376.22	166	(2)	166.00	210.22	11	11	19.11
1993	22,016.33	8,773	(2)	8,773.00	13,243.33	12	12	1,103.61
1994	19,130.19	6,785	(2)	6,785.00	12,345.19	13	13	949.63
1994	0.00	0	(2)	0.00	0.00	13	13	0.00
1995	0.00	0	(2)	0.00	0.00	14	14	0.00
1996	0.00	0	(2)	0.00	0.00	15	15	0.00
1997	0.00	0	(2)	0.00	0.00	16	16	0.00
1998	15,978.08	2,717	(2)	2,717.00	13,261.08	17	17	780.06
1999	3,603.02	440	(2)	440.00	3,163.02	18	18	175.72
2000	5,963.88	438	(2)	438.00	5,525.88	19	19	290.84
2001	2,238.57	55	(2)	55.00	2,183.57			
	102,746.14	35,616		35,616.00	67,130.14		4.92%	5,053.47
Book Rese				39,144.35				
Starting Point Depreciation Reserve				35,616.00				
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-3,528.35	-3,528.35		20	-176.42
Total Amortization Amount							4.75%	4,877.05

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 394.4 - Vehicle Refueling Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1986	243,205.76	162,753	(2)	162,753.00	80,452.76	5	16,090.55
1987	3,402.61	2,161	(2)	2,161.00	1,241.61	6	206.94
1988	2,890.28	1,732	(2)	1,732.00	1,158.28	7	165.47
1989	0.00	0	(2)	0.00	0.00	8	0.00
1990	0.00	0	(2)	0.00	0.00	9	0.00
1991	140,655.25	67,885	(2)	67,885.00	72,770.25	10	7,277.03
1992	73,962.19	32,627	(2)	32,627.00	41,335.19	11	3,757.74
1993	165,847.96	66,088	(2)	66,088.00	99,759.96	12	8,313.33
1994	48,249.96	17,112	(2)	17,112.00	31,137.96	13	2,395.23
1995	0	0	(2)	0.00	0.00	14	0.00
1996	61,784.64	16,314	(2)	16,314.00	45,470.64	15	3,031.38
1997	18.20	4	(2)	4.00	14.20	16	0.89
1998	34,000.89	5,781	(2)	5,781.00	28,219.89	17	1,659.99
1999	0.00	0	(2)	0.00	0.00	18	0.00
2000	0.00	0	(2)	0.00	0.00	19	0.00
2001	64,813.03	1,594	(2)	1,594.00	63,219.03	20	3,160.95
	838,830.77	374,051		374,051.00	464,779.77	5.49%	46,059.49
Book Rese				561,054.56			
Starting Point Depreciation Reserve				374,051.00			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-187,003.56	-187,003.56	20	-9,350.18
Total Amortization Amount						4.38%	36,709.31

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 397.1 - Radio Communication Equipment (Fixed)

Development of Annual Amortization Amount Over Estimated Average Life of Propert

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1968	0.08	0	(1)	0.08	0.00	0	0.00
1969	1.94	2	(1)	1.94	0.00	0	0.00
1970	39.09	43	(1)	39.09	0.00	0	0.00
1971	519.05	571	(1)	519.05	0.00	0	0.00
1972	557.25	613	(1)	557.25	0.00	0	0.00
1973	170.06	187	(1)	170.06	0.00	0	0.00
1974	386.38	425	(1)	386.38	0.00	0	0.00
1975	2,987.20	3286	(1)	2,987.20	0.00	0	0.00
1976	4,975.40	5473	(1)	4,975.40	0.00	0	0.00
1977	2,475.07	2632	(1)	2,475.07	0.00	0	0.00
1978	6,250.64	6608	(1)	6,250.64	0.00	0	0.00
1979	7,343.88	7661	(1)	7,343.88	0.00	0	0.00
1980	23,332.99	23943	(1)	23,332.99	0.00	0	0.00
1981	26,278.13	26491	(1)	26,278.13	0.00	0	0.00
1982	14,586.58	14439	(1)	14,586.58	0.00	0	0.00
1983	32,258.42	31300	(1)	32,258.42	0.00	0	0.00
1984	34,264.05	32494	(1)	34,264.05	0.00	0	0.00
1985	31,553.45	29126	(1)	31,553.45	0.00	0	0.00
1986	83,052.08	74209	(1)	83,052.08	0.00	0	0.00
1987	32,797.40	28186	(2)	28,186.00	4,611.40	1	4,611.40
1988	52,271.97	42890	(2)	42,890.00	9,381.97	2	4,690.99
1989	23,174.87	18011	(2)	18,011.00	5,163.87	3	1,721.29
1990	22,843.44	16672	(2)	16,672.00	6,171.44	4	1,542.86
1991	65,839.50	44,695	(2)	44,695.00	21,144.50	5	4,228.90
1992	23,976.92	14,979	(2)	14,979.00	8,997.92	6	1,499.65
1993	1,878.61	1,067	(2)	1,067.00	811.61	7	115.94
1994	980.52	498	(2)	498.00	482.52	8	60.32
1995	25,829.71	11,524	(2)	11,524.00	14,305.71	9	1,589.52
1996	30,098.37	11,497	(2)	11,497.00	18,601.37	10	1,860.14
1997	9,884.40	3,121	(2)	3,121.00	6,763.40	11	614.85
1998	2,978.64	738	(2)	738.00	2,240.64	12	186.72
1999	0.00	0	(2)	0.00	0.00	13	0.00
2000	71,469.03	7,691	(2)	7,691.00	63,778.03	14	4,555.57
2001	11,131.90	401	(2)	401.00	10,730.90	15	715.39
	646,187.02	461,473		473,001.74	173,185.28	4.33%	27,993.55
Book Reserve				409,277.55			
Starting Point Depreciaition Reserve				473,001.74			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				63,724.19	63,724.19	15	4,248.28
Total Amortization Amount						4.99%	32,241.83

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 397.2 - Radio Communication Equipment (Mobile)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1975	9,731.21	9,731	(1)	9,731.21	0.00	0	0.00
1976	39,866.18	39,866	(1)	39,866.18	0.00	0	0.00
1977	39,252.58	37,944	(1)	39,252.58	0.00	0	0.00
1978	35,627.74	34,241	(1)	35,627.74	0.00	0	0.00
1979	38,356.69	36,375	(1)	38,356.69	0.00	0	0.00
1980	47,532.29	44,341	(1)	47,532.29	0.00	0	0.00
1981	50,016.71	45,839	(1)	50,016.71	0.00	0	0.00
1982	34,249.52	30,820	(1)	34,249.52	0.00	0	0.00
1983	30,655.73	27,041	(1)	30,655.73	0.00	0	0.00
1984	25,214.42	21,738	(1)	25,214.42	0.00	0	0.00
1985	47,678.88	40,010	(1)	47,678.88	0.00	0	0.00
1986	22,183.24	18,019	(1)	22,183.24	0.00	0	0.00
1987	23,044.45	18,004	(2)	18,004.00	5,040.45	1	5,040.45
1988	53,612.66	39,991	(2)	39,991.00	13,621.66	2	6,810.83
1989	41,151.18	29,074	(2)	29,074.00	12,077.18	3	4,025.73
1990	129,469.32	85,901	(2)	85,901.00	43,568.32	4	10,892.08
1991	52,239.07	32,238	(2)	32,238.00	20,001.07	5	4,000.21
1992	69,736.92	39,605	(2)	39,605.00	30,131.92	6	5,021.99
1993	52,917.15	27,313	(2)	27,313.00	25,604.15	7	3,657.74
1994	77,344.49	35,731	(2)	35,731.00	41,613.49	8	5,201.69
1995	53,080.07	21,530	(2)	21,530.00	31,550.07	9	3,505.56
1996	52,745.50	18,316	(2)	18,316.00	34,429.50	10	3,442.95
1997	10,478.24	3,007	(2)	3,007.00	7,471.24	11	679.20
1998	27,953.14	6,295	(2)	6,295.00	21,658.14	12	1,804.85
1999	0.00	0	(2)	0.00	0.00	13	0.00
2000	180,485.36	17,658	(2)	17,658.00	162,827.36	14	11,630.53
2001	40,400.26	1,324	(2)	1,324.00	39,076.26	15	2,605.08
	1,285,023.00	761,952		796,352.19	488,670.81	5.32%	68,318.88
Book Reserve				1,034,021.53			
Starting Point Depreciation Reserve				796,352.19			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-237,669.34	-237,669.34	15	-15,844.62
Total Amortization Amount						4.08%	52,474.26

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 397.3 - General Telephone Communication Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 10
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1984	25,691.19	21,965	(1)	25,691.19	0.00	0	0.00
1985	22,226.48	18,683	(1)	22,226.48	0.00	0	0.00
1986	7,931.65	6,489	(1)	7,931.65	0.00	0	0.00
1987	12,018.09	9,538	(1)	12,018.09	0.00	0	0.00
1988	4,652.33	3,572	(1)	4,652.33	0.00	0	0.00
1989	1,025.33	758	(1)	1,025.33	0.00	0	0.00
1990	46,487.84	32,876	(1)	46,487.84	0.00	0	0.00
1991	31,119.91	20,855	(1)	31,119.91	0.00	0	0.00
1992	4,685.71	2,941	(2)	2,941.00	1,744.71	1	1,744.71
1993	30,900.54	17,920	(2)	17,920.00	12,980.54	2	6,490.27
1994	39,866.57	21,003	(2)	21,003.00	18,863.57	3	6,287.86
1995	27,829.98	13,048	(2)	13,048.00	14,781.98	4	3,695.50
1996	128,560.19	52,249	(2)	52,249.00	76,311.19	5	15,262.24
1997	204,550.06	69,530	(2)	69,530.00	135,020.06	6	22,503.34
1998	31,208.98	8,418	(2)	8,418.00	22,790.98	7	3,255.85
1999	10,343.81	2,030	(2)	2,030.00	8,313.81	8	1,039.23
2000	83,627.04	10,012	(2)	10,012.00	73,615.04	9	8,179.45
2001	67,095.53	2,719	(2)	2,719.00	64,376.53	10	6,437.65
	779,821.23	314,606		351,022.82	428,798.41	9.60%	74,896.10
Book Reserve				419,620.16			
Starting Point Depreciation Reserve				351,022.82			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				-68,597.34	-68,597.34	10	-6,859.73
Total Amortization Amount						8.72%	68,036.36

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 397.5 - Supervisory & Telemetering Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1966	26.04	22	(1)	26.04	0.00	0	0.00
1967	5.81	5	(1)	5.81	0.00	0	0.00
1968	4,040.60	3,353	(1)	4,040.60	0.00	0	0.00
1969	103.88	85	(1)	103.88	0.00	0	0.00
1970	2,858.24	2,298	(1)	2,858.24	0.00	0	0.00
1971	0.00	0	(1)	0.00	0.00	0	0.00
1972	0.00	0	(1)	0.00	0.00	0	0.00
1973	985.77	752	(1)	985.77	0.00	0	0.00
1974	358.45	268	(1)	358.45	0.00	0	0.00
1975	0.00	0	(1)	0.00	0.00	0	0.00
1976	0.00	0	(1)	0.00	0.00	0	0.00
1977	0.00	0	(1)	0.00	0.00	0	0.00
1978	0.00	0	(1)	0.00	0.00	0	0.00
1979	0.00	0	(1)	0.00	0.00	0	0.00
1980	0.00	0	(1)	0.00	0.00	0	0.00
1981	0.00	0	(1)	0.00	0.00	0	0.00
1982	0.00	0	(1)	0.00	0.00	0	0.00
1983	0.00	0	(1)	0.00	0.00	0	0.00
1984	0.00	0	(1)	0.00	0.00	0	0.00
1985	0.00	0	(1)	0.00	0.00	0	0.00
1986	0.00	0	(1)	0.00	0.00	0	0.00
1987	0.00	0	(2)	0.00	0.00	1	0.00
1988	0.00	0	(2)	0.00	0.00	2	0.00
1989	0.00	0	(2)	0.00	0.00	3	0.00
1990	0.00	0	(2)	0.00	0.00	4	0.00
1991	0.00	0	(2)	0.00	0.00	5	0.00
1992	0.00	0	(2)	0.00	0.00	6	0.00
1993	0.00	0	(2)	0.00	0.00	7	0.00
1994	0.00	0	(2)	0.00	0.00	8	0.00
1995	0.00	0	(2)	0.00	0.00	9	0.00
1996	0.00	0	(2)	0.00	0.00	10	0.00
1997	0.00	0	(2)	0.00	0.00	11	0.00
1998	2,188.46	432	(2)	432.00	1,756.46	12	146.37
1999	0.00	0	(2)	0.00	0.00	13	0.00
2000	0.00	0	(2)	0.00	0.00	14	0.00
2001	37,728.70	1,175	(2)	1,175.00	36,553.70	15	2,436.91
	48,295.95	8,390		9,985.79	38,310.16	5.35%	2,583.29
Book Reserve				46,185.03			
Starting Point Depreciation Reserve				9,985.79			
Book/Amortization Starting Point Depr Reserve Varianc				-36,199.24	-36,199.24	15	-2,413.28
(Amortize over Amortization Period)							
Total Amortization Amount						0.35%	170.00

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 397.8 - Network Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 5
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1992	4,119.65	4,120	(1)	4,119.65	0.00	0	0.00
1993	929.34	929	(1)	929.34	0.00	0	0.00
1994	4,786.29	4,308	(1)	4,786.29	0.00	0	0.00
1995	72,165.93	63,311	(1)	72,165.93	0.00	0	0.00
1996	5,967.06	4,937	(1)	5,967.06	0.00	0	0.00
1997	54,268.53	40,203	(2)	40,203.00	14,065.53	1	14,065.53
1998	219,949.99	135,265	(2)	135,265.00	84,684.99	2	42,342.50
1999	30,375.12	14,005	(2)	14,005.00	16,370.12	3	5,456.71
2000	289,947.62	83,137	(2)	83,137.00	206,810.62	4	51,702.66
2001	142,438.69	13,932	(2)	13,932.00	128,506.69	5	25,701.34
	824,948.22	364,147		374,510.27	450,437.95	16.88%	139,268.72
Book Reserve				330,668.70			
Starting Point Depreciation Reserve				374,510.27			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				43,841.57	43,841.57	5	8,768.31
Total Amortization Amount						17.95%	148,037.04

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 4

Montana-Dakota Utilities Company
Common Plant
Account 398.00 - Miscellaneous Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20
Calculation Year: 2001

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1965	0.07	0	(1)	0.07	0.00	0	0.00
1966	0.61	1	(1)	0.61	0.00	0	0.00
1967	6.90	6	(1)	6.90	0.00	0	0.00
1968	24.86	22	(1)	24.86	0.00	0	0.00
1969	412.36	366	(1)	412.36	0.00	0	0.00
1970	293.15	257	(1)	293.15	0.00	0	0.00
1971	1,721.07	1,483	(1)	1,721.07	0.00	0	0.00
1972	1,266.40	1,074	(1)	1,266.40	0.00	0	0.00
1973	812.89	678	(1)	812.89	0.00	0	0.00
1974	2,388.48	1,960	(1)	2,388.48	0.00	0	0.00
1975	4,312.72	3,476	(1)	4,312.72	0.00	0	0.00
1976	2,194.65	1,735	(1)	2,194.65	0.00	0	0.00
1977	3,015.98	2,336	(1)	3,015.98	0.00	0	0.00
1978	3,683.05	2,789	(1)	3,683.05	0.00	0	0.00
1979	8,119.41	5,999	(1)	8,119.41	0.00	0	0.00
1980	7,260.95	5,221	(1)	7,260.95	0.00	0	0.00
1981	6,648.93	4,641	(1)	6,648.93	0.00	0	0.00
1982	13,915.55	9,399	(2)	13,915.55	0.00	1	0.00
1983	4,971.62	3,239	(2)	4,971.62	0.00	2	0.00
1984	4,809.36	3,011	(2)	4,809.36	0.00	3	0.00
1985	7,165.93	4,295	(2)	7,165.93	0.00	4	0.00
1986	14,352.71	8,198	(2)	14,352.71	0.00	5	0.00
1987	41,087.40	22,260	(2)	41,087.40	0.00	6	0.00
1988	5,680.41	2,903	(2)	5,680.41	0.00	7	0.00
1989	27,362.82	13,113	(2)	27,362.82	0.00	8	0.00
1990	43,519.58	19,418	(2)	43,519.58	0.00	9	0.00
1991	11,719.06	4,830	(2)	11,719.06	0.00	10	0.00
1992	6,337.32	2,389	(2)	2,389.00	3,948.32	11	358.94
1993	35,426.75	12,075	(2)	12,075.00	23,351.75	12	1,945.98
1994	48,383.48	14,696	(2)	14,696.00	33,687.48	13	2,591.34
1995	34,402.42	9,144	(2)	9,144.00	25,258.42	14	1,804.17
1996	24,449.82	5,549	(2)	5,549.00	18,900.82	15	1,260.05
1997	31,707.42	5,939	(2)	5,939.00	25,768.42	16	1,610.53
1998	8,056.46	1,183	(2)	1,183.00	6,873.46	17	404.32
1999	19,833.33	2,098	(2)	2,098.00	17,735.33	18	985.30
2000	41,398.58	2,646	(2)	2,646.00	38,752.58	19	2,039.61
2001	126,152.43	2,709	(2)	2,709.00	123,443.43	20	6,172.17
	592,894.93	181,138		275,174.92	317,720.01	3.23%	19,172.41
Book Reserve				372,786.90			
Starting Point Depreciation Reserve				275,174.92			
Book/Amortization Starting Point Depr Reserve Varian				-97,611.98	-97,611.98	20	-4,880.60
(Amortize over Amortization Period)							
Total Amortization Amount						2.41%	14,291.81

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

MONTANA-DAKOTA UTILITIES COMPANY

Common Plant

General

This report sets forth the results of our study of the depreciable property of the Montana-Dakota Utilities Company (the Company) as of December 31, 2001 and contains the basic parameters (recommended average service lives and life characteristics) for the proposed average remaining life depreciation rates until a subsequent service life study is completed. All average service lives set forth in this report are developed based upon plant in service as of December 31, 2001.

The scope of the study included an analysis of Company historical data through December 31, 2001, discussions with Company management staff to identify prior and prospective factors affecting the Company's plant in service, as well as interpretation of past service life data experience and future life expectancies to determine the appropriate average service lives of the Company's surviving plant. The service lives and life characteristics, resulting from the in-depth study, were utilized together with the Company's plant in service and book depreciation reserve to determine the recommended Average Remaining Life (ARL) depreciation rates related to the Company's plant in service as of December 31, 2001.

In preparing the study, the Company's historical investment data were studied using various service life analysis techniques. Further, discussions were held with the Company's management to obtain an overview of the Company's facilities and to discuss the general scope of operations together with other factors which could have a bearing on the service lives of the Company's property. Finally, the study results were tempered by information gathered during plant inspection tours of a representative portion of the Company's property.

The Company maintains a property record containing a summary of its fixed capital investments by property account. This investment data was analyzed and summarized by property group and/or sub group and vintage then utilized as a basis for the various

depreciation calculations.

Depreciation Study Overview

There are numerous methods utilized to recover property investment depending upon the goal. For example, accelerated methods such as double declining balance and sum of years digits are methods used in tax accounting to motivate additional investments. Broad Group (BG) and Equal Life Group (ELG) are both Straight Line Grouping Procedures recognized and utilized by various regulatory jurisdictions depending upon the policy of the specific agency.

The Straight Line (Group) Method of depreciation utilized in this study to develop the recommended depreciation rates is the Broad Group Procedure together with the Average Remaining Life Technique. The use of this procedure and technique is based upon recovering the net book cost (original cost less book reserve) of the surviving plant in service over its estimated remaining useful life. Any variance between the book reserve and an implied theoretical calculated reserve is compensated for under this procedure. That is, as the Company's book reserve increases above or declines below the theoretical reserve at a specific point in time, the Company's average remaining life depreciation rate in subsequent years will be increased or decreased to compensate for the variance, thereby, assuring full recovery of the Company's investment by the end of the property's life.

The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The annual depreciation amount to be utilized is based upon the remaining productive life over which the undepreciated capital investment needs to be recovered. The determination of the productive remaining life for each property group usually includes an in-depth study of past experience in addition to estimates of future expectations.

Annual Depreciation Accrual

Through the utilization of the Average Remaining Life Technique, the Company will

recover the undepreciated fixed capital investment in the appropriate amounts as annual depreciation expense in each year throughout the remaining life of the property. The procedure incorporates the future life expectancy of the property, the vintaged surviving plant in service, and estimated net salvage, together with the book depreciation reserve balance to develop the annual depreciation rate for each property account. Accordingly, the ARL technique meets the objective of providing a straight line recovery of the undepreciated fixed capital property investment.

As indicated, the use of the Average Remaining Life Technique results in charging the appropriate annual depreciation amounts over the remaining life of the property to insure full recovery by end of life. That does not mean that once an average remaining life is estimated, it can not be changed at any point throughout the service life, but that the annual expense is calculated on a Straight Line Method rather than by the previously mentioned, "sum of the years digits" or "double declining balance" methods, etc. The "group" refers to the method of calculating annual depreciation on the summation of the investment in any one depreciable group or plant account rather than calculating depreciation for each individual unit.

Under Broad Group depreciation some units may be over depreciated and other units may be under depreciated at the time when they are retired from service, but overall, the account is fully depreciated when average service life is attained. By comparison, Equal Life Group depreciation rates are designed to fully accrue the cost of the asset group by the time of retirement. For both the Broad Group and Equal Life Group Procedures the full cost of the investment is credited to plant in service when the retirement occurs and likewise the depreciation reserve is debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption the retired property was at average service life.

Group Depreciation Procedures

Group depreciation procedures are utilized to depreciate property when more than one

item of property is being depreciated. Such a procedure is appropriate because all of the items within a specific group typically do not have identical service lives, but have lives which are dispersed over a range of time. Utilizing a group depreciation procedure allows for a condensed application of depreciation rates to groups of similar property in lieu of extensive depreciation calculations on an item by item basis. The two more common group depreciation procedures are the Broad Group (BG) and Equal Life Group (ELG) approach.

In developing depreciation rates using the Broad Group procedure, the annual depreciation rate is based on the average of the overall group, which is then applied to the group's surviving original cost investment. A characteristic of this procedure is that retirements of individual units occurring prior to average service life will be under depreciated, while individual units retired after average service life will be over depreciated when removed from service, but overall, the group investment will achieve full recovery by the end of the life of the total property group. That is, the under recovery occurring early in the life of the account is balanced by the over recovery occurring subsequent to average service life. In summary, the cost of the investment is complete at the end of the property's life cycle, but the rate of recovery does not match the consumption pattern which was used to provide service to the company's customers.

Under the average service life procedure, the annual depreciation rate is calculated by the following formula:

$$\text{Annual Accrual Rate, Percent} = \frac{100\% - \text{Salvage}}{\text{Average Service Life}} \times 100$$

The application of the broad group procedure to life span groups results in each vintage investment having a different average service life. This circumstance exists because the concurrent retirement of all vintages at the anticipated retirement year results in truncating and, therefore, restricting the life of each successive years vintage investment. An average service life is calculated for each vintage investment in accordance with the above formula. Subsequently, a composite service life and depreciation rate is calculated relative to all vintages within the property group by weighting the life for each vintage by the

related surviving vintage investment within the group.

In the Equal Life Group, the property group is subdivided, through the use of plant life tables, into equal life groups. In each equal life group, portions of the overall property group includes that portion which experiences the life of the specific sub-group. The relative size of each sub-group is determined from the overall group life characteristic (property dispersion curve). This procedure both overcomes the disadvantage of voluminous record requirements of unit depreciation, as well as, eliminates the need to base depreciation on overall lives as required under the broad group procedure. The application of this procedure results in each sub-group of the property having a single life. In this procedure, the full cost of short lived units is accrued during their lives leaving no under accruals to be recovered by over accruals on long lived plant. The annual depreciation for the group is the summation of the depreciation accruals based on the service life of each Equal Life Group.

The ELG Procedure is superior to the BG Procedure because it allocates the capital cost of a group property to annual expense in accordance with the consumption of the property group providing service to customers. In this regard, the company's customers are more appropriately charged with the cost of the property consumed in providing them service during the applicable service period. The more timely return of plant cost is accomplished by fully accruing each unit's cost during its service life, thereby, not only reducing the risk of incomplete cost recovery, but also the procedure results in less return on rate base over the life of a depreciable group. The total depreciation expense is the same for all procedures which allocate the full capital cost to expense, but at any specific point in time, the depreciated original cost is less under the ELG procedure than under the BG procedure. This circumstance exists because under the equal life group procedure, the rate base is not maintained at a level of greater than the future service value of the surviving plant as is the case when using the average service life procedure. Consequently, the total return required from the ratepayers is less under the ELG procedure.

While the equal life group procedure has been known to depreciation experts for

many years widespread interest in applying the procedure developed only after high speed electronic computers became available to perform the large volume of arithmetic computations required in developing ELG based depreciation lives and rates. The table on the following page illustrates the procedure for calculating equal life group depreciation accrual rates and summarizes the results of the underlying calculations. Depreciation rates are determined for each age interval (one year increment) during the life of a group of property which was installed in a given year or vintage group. The age of the vintage group is shown in column (A) of the ELG table. The percent surviving at the beginning of each age interval is determined from the Iowa 10-R3 survivor curve which is set forth in column (B). The percent retired during each age interval, as shown in column (C), is the difference between the percent surviving at successive age intervals. Accordingly, the percentage amount of the vintage group retired defines the size of each equal life group. For example, during the interval 3 1/2 to 4 1/2, 1.93690 percent of the vintage group is retired at an average age of four years. In this case, the 1.93690 percent of the group experiences an equal life of four years. Likewise, 3.00339 percent is retired during the interval 4 1/2 to 5 1/2 and experiences a service life of five years. Further, 4.42969 percent experiences a six-year life; etc. Calculations are made for each age interval from the zero age interval through the end of the life of the vintage group. The average service life for each age interval's equal life group is shown in column (E) of the table.

The amount to be accrued annually for each equal life group is equal to the percentage retired in the equal life group divided by its service life. Inasmuch as additions and retirements are assumed, for calculation purposes, to occur at midyear only one-half of the equal life group's annual accrual is allocated to expense during its first and last years of service life. The accrual amount for the property retired during age interval 0 to 1/2 must be equal to the amount retired to insure full recovery of that component during that period. The accruals for each equal life group during the age intervals of the vintage group's life cycle are shown in column (F). The total accrual for a given year is the summation of the equal life

XYZ UTILITY COMPANY
CALCULATION OF ASL, ARL AND ACCRUED DEPRECIATION FACTORS
BASED UPON AN IOWA 10-R3 CURVE USING THE EQUAL LIFE GROUP (ELG) PROCEDURE

							EQUAL LIFE GROUP PROCEDURE			
AGE AT BEGIN OF INTERVAL	LIFE TABLE BEGIN OF INTERVAL	RETIREMENT DURING INTERVAL	AVERAGE SURVIVING	AGE OF AMOUNT RETIRED	AMOUNT FOR EACH LIFE GROUP	AMOUNT FOR REMAINING LIFE GROUPS	AVERAGE SERVICE LIFE	AVERAGE REMAINING LIFE	ELG/ARL DEPR RATE	ACCRUED DEPR RES FACTOR
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
0.0	1.0000000	0.0009198	0.9995401	0.25	0.0009198	0.0583036	8.57	8.57	11.67	0.0000000
0.5	0.9990802	0.0033314	0.9974145	1.0	0.0033314	0.1131019	8.82	8.32	11.34	0.0566975
1.5	0.9957488	0.0065393	0.9924792	2.0	0.0032697	0.1098013	9.04	7.54	11.06	0.1659501
2.5	0.9892095	0.0117037	0.9833577	3.0	0.0039012	0.1062159	9.26	6.76	10.80	0.2700337
3.5	0.9775058	0.0193690	0.9678213	4.0	0.0048422	0.1018442	9.50	6.00	10.52	0.3683062
4.5	0.9581368	0.0300339	0.9431199	5.0	0.0060068	0.0964196	9.78	5.28	10.22	0.4600565
5.5	0.9281029	0.0442969	0.9059545	6.0	0.0073828	0.0897248	10.10	4.60	9.90	0.5447146
6.5	0.8838060	0.0631367	0.8522377	7.0	0.0090195	0.0815237	10.45	3.95	9.57	0.6217794
7.5	0.8206693	0.0876232	0.7768577	8.0	0.0109529	0.0715375	10.86	3.36	9.21	0.6906424
8.5	0.7330461	0.1166879	0.6747022	9.0	0.0129653	0.0595783	11.32	2.82	8.83	0.7505770
9.5	0.6163582	0.1431836	0.5447664	10.0	0.0143184	0.0459365	11.86	2.36	8.43	0.8010714
10.5	0.4731746	0.1533568	0.3964962	11.0	0.0139415	0.0318066	12.47	1.97	8.02	0.8423003
11.5	0.3198178	0.1363216	0.2516570	12.0	0.0113601	0.0191557	13.14	1.64	7.61	0.8753616
12.5	0.1834962	0.0975199	0.1347363	13.0	0.0075015	0.0097249	13.85	1.35	7.22	0.9022159
13.5	0.0859763	0.0559043	0.0580242	14.0	0.0039932	0.0039775	14.59	1.09	6.85	0.9254232
14.5	0.0300720	0.0244398	0.0178521	15.0	0.0016293	0.0011663	15.31	0.81	6.53	0.9473077
15.5	0.0056322	0.0055324	0.0028660	16.0	0.0003458	0.0001788	16.03	0.53	6.24	0.9667657
16.5	0.0000998	0.0000998	0.0000499	17.0	0.0000059	0.0000029	17.00	0.50	5.88	0.9705882
17.5	0.0000000	0.0000000	0.0000000	18.0	0.0000000	0.0000000				
		1.0000000				1.0000000				

Table 5

group accruals for that year. For example, the total accrual for the second year, as shown in column (G), is 11.31019 percent and is the sum of all succeeding years remaining equal life group accruals plus one half of the current years life group accrual listed in column (F). For the zero age interval year, the total accrual is equal to one half of the sum of all succeeding years remaining equal life accruals plus the amount for the zero interval equal life group accrual. The one half year accrual for the zero age interval is consistent with the half year convention relative to property during its installation year. The sum of the annual accruals for each age interval contained in column (G) total to 1.000 demonstrating that the developed rates will recover 100% of plant no more and no less. The annual accrual rate which will result in the accrual amount is the ratio of the accrual amount (11.31019 percent) to the average percent surviving during the interval, column (D), (99.74145 percent), which is a rate of 11.34% (column J). Column (J) contains a summary of the accrual rates for each age interval of the property groups life cycle based upon an Iowa 10-R3 survivor curve.

Remaining Life Technique

In the Average Remaining Life depreciation technique, the annual accrual is calculated according to the following formula where, (A) the annual depreciation for each group equals, (D) the depreciable cost of plant, less (U) the accumulated provision for depreciation, less (S) the estimated future net salvage, divided by (R) the composite remaining life of the group:

$$A = \frac{D - U - S}{R}$$

The annual accrual rate (a) is expressed as a percentage of the depreciable plant balance by dividing the equation by (D) the depreciable cost of plant times 100:

$$(a) = \frac{D - U - S}{R} \times \frac{1}{D} \times 100$$

As further indicated by the equation, the accumulated provision for depreciation by vintage is required in order to calculate the remaining life depreciation rate for each property group. In practice, most often such detail is not available; therefore, composite remaining

lives are determined for each depreciable group, i.e., property account.

The remaining life for a depreciable group is calculated by first determining the remaining life for each vintage year in which there is surviving investment. This is accomplished by solving the area under the survivor curve selected to represent the average life and life characteristic of the property account. The remaining life for each vintage is composited by dividing (D) the depreciable cost of each vintage, by (L) its average service life, and multiplying this ratio by its average remaining life (E). The composite remaining life of the group (R) equals the sums of products divided by the sum of the quotients:

$$R\ Group = \frac{\sum D/L \times E}{\sum D/L}$$

The functional level accumulated provision for depreciation, which was the basis for developing the composite average remaining life accrual and annual depreciation rate for each property account as per this report, was obtained from the Company's books and records. The functional level depreciation reserve was further allocated to each property account and sub-account based upon a detailed theoretical depreciation reserve as of December 31, 2001.

Salvage

Net salvage is the difference between gross salvage, or what is received when an asset is disposed of, and the cost of removing it from service. Salvage experience is normally included with the depreciation rate so that current accounting periods reflect a proportional share of the ultimate abandonment and removal cost or salvage received at the end of the property service life. Historical Net salvage analysis results are expressed as a percentage of the plant retired by dividing the dollars of net salvage incurred by the original cost of the plant retired. Net salvage is said to be positive if gross salvage exceeds the cost of removal, but if cost of removal exceeds gross salvage the result is then negative salvage.

The cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise removing plant and related transportation, handling, and overheads in connection with the work, as well as environmental clean up costs associated

with the property. Salvage includes proceeds received for the sale of plant and materials or the return of equipment to stores for reuse.

Net salvage experience is studied for a period of years to determine the trends which have occurred in the past. These trends are considered together with any changes that are anticipated in the future to determine the future net salvage factor for remaining life depreciation purposes. The goal of incorporating net salvage into the annual depreciation rate is to appropriately allocate the net cost of each asset group to each accounting period. The net cost of each asset group must include not only the original cost when placed in service, but also the net salvage, positive or negative, that will be incurred at end of live. The inclusion, in the net salvage amount, of all benefits received and/or costs incurred is premised on the concept that property ownership includes the responsibility of the proper disposal of the facilities at end of life. Therefore, if current customers benefit from the property's use, the customer should pay/receive a pro rata share of all costs incurred and/or receipts generated in the retirement, abandonment and/or removal of the assets.

The analysis of net salvage is routinely based upon identification of the individual components, (i.e. gross salvage and cost of removal) included in net salvage amount. This analysis identifies that the component items experience different trends over time. That is, as property continues to age, gross salvage routinely declines, while with the passage of time cost of removal tends to increase in conjunction with ever increasing labor rates. On an aggregate basis, most historical retirements from each property group, routinely occur at an average age that is less than the average service life of the account. Accordingly, the experienced historical salvage analysis, with regard to gross salvage, will most often be overstated relative to anticipated future gross salvage. By comparison, the historical analysis will typically be understated with regard to future cost of removal. That is, in general terms, it can be assumed that with the increased passage of time, any future positive net salvage will likely be lower, while future negative net salvage will likely be higher than the overall levels experienced in the past. Because of these future events, it is important that the overall

historical net salvage experience should only be used as a benchmark for estimating future net salvage, and that salvage trends as well as other future factors be considered in the process of estimating future net salvage. Otherwise, the future net salvage estimates will clearly understate the future net negative salvage and overstate any gross salvage that will occur in conjunction with future retirements.

Service Lives

Several factors contribute to the length of time or average service life which the property achieves. The three (3) major categories under which these factors fall are: (1) physical; (2) functional, and; (3) contingent casualties.

The physical category includes such things as deterioration, wear and tear and the action of the natural elements. The functional category includes inadequacy, obsolescence and requirements of governmental authorities. Obsolescence occurs when it is no longer economically feasible to use the property to provide service to customers or when technological advances have provided a substitute of superior performance. The remaining factor of contingent casualties relates to retirements caused by accidental damage or construction activity of one type or another.

In performing the life analysis for any property being studied, both past experience and future expectations must be considered in order to fully evaluate the circumstances which may have a bearing on the remaining life of the property. This ensures the selection of an average service life which best represents the expected life of each property investment.

Survivor Curves

The preparation of a depreciation study or theoretical depreciation reserve typically incorporates smooth curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves generally used are the family of curves developed at Iowa State University which are widely used and accepted throughout the utility industry.

The shape of the curves within the Iowa family are dependent upon whether the

maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if occurring at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right ®) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

Many times, actual Company data has not completed its life cycle, therefore, the survivor table generated from the Company data is not extended to zero percent surviving. This situation requires an estimate be made with regard to the remaining segment of the property group's life experience. Further, actual Company experience is often erratic, making its utilization for average service life estimating difficult. Accordingly, the Iowa curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Study Procedures

Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical retirements, current and future construction, historical experience and future expectations of salvage and cost of removal as related to plant investment. Service lives are affected by many different factors, some of which can be obtained from studying plant experience, others which may rely heavily on future expectations. When physical aspects are the controlling factor in determining the service life of property, historical experience is a valuable tool in selecting service lives. In the case where changing technology or a less costly alternative develops, then historical experience is of lesser value.

While various methods are available to study historical data, the principal methods utilized to determine average service lives for a Company's property are the Retirement Rate Method, the Simulated Plant Record Method, the Life Span Method, and the Judgement Method.

Retirement Rate Method - The Retirement Rate Method uses actual Company

retirement experience to develop a survivor curve (observed life table) which is used to determine the average service life being experienced in the account under study. Computer processing provides the opportunity to review various experience bands throughout the life of the account to observe trends and changes. For each experience band studied, the "observed life table" is constructed based on retirement experience within the band of years. In some cases, the total life of the account has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is this "stub curve" or total life curve, if achieved, which is matched or fitted to a standard Survivor curve. The matching process is performed both by computer analysis, using a least square technique, and by manually plotting observed life tables to which smooth curves are fitted. The fitted smooth curve provides the basis to determine the average service life of the property group under study.

Simulated Balances Method - In this method of analysis, simulated surviving balances are determined for each balance included in the test band by multiplying each year's original gross additions installed by the Company by the appropriate factor of each Standard Survivor Curve, summing the products, and comparing the results with the related year end plant balance to determine the "best fitting" curve and life within the test period. Various test bands are reviewed to determine trends or changes to indicated service lives in various bands of years. By definition, the curve with the "best fit" is the curve which produces simulated plant balances that most closely matches the actual plant balances as determined by the sum of the "least squares". The sum of the "least squares" is arrived at by starting with the difference between the simulated balances and the actual balance for a given year, squaring the difference, and the curve which produces the smallest sum (of squared difference) is judged to be the "best fit".

Period Retirements Method - The application of the Period Retirements Method is similar to the "Simulated Plant Balances" Method, except the procedure utilizes a Standard Survivor Curve and service life to simulate annual retirements instead of balances in performing the "least squares" fitting process during the test period. This procedure does

tend to experience wider fluctuations due to the greater variations in level of experienced retirements versus additions and balances thereby producing greater variation in the study results.

Life Span Method - The Life Span or Forecast Method is a method utilized to study various accounts in which the expected retirement dates of specific property or locations can be reasonably estimated. In the Life Span Method, an estimated probable retirement year is determined for each location of the property group. An example of this would be a structure account, in which the various segments of the account are "life spanned" to a probable retirement date which is determined after considering a number of factors, such as management plans, industry standards, the original construction date, subsequent additions, resultant average age and the current - as well as the overall - expected service life of the property being studied. If in the past the property has experienced interim retirements, these are studied to determine an interim retirement rate. Otherwise, interim retirement rate parameters are estimated for properties which are anticipated to experience such retirements. The selected interim service life parameters (Iowa curve and life) are then used with the vintage investment and probable retirement year of the property to determine the average remaining life as of the study date. No attempt is made to include any anticipated additions to the property subsequent to the study date. The recovery of such additions if made, is reflected when preparing subsequent depreciation studies.

Judgement Method - Standard quantitative methods such as the Retirement Rate Method, Simulated Plant Record Method, etc. are normally utilized to analyze a Company's available historical service life data. The results of the analysis together with information provided by management as well as judgement are utilized in estimating the prospective recommended average service lives. However, there are some circumstances where sufficient retirements have not occurred, or where prospective plans or guidelines are unavailable. In these circumstances, judgement alone is utilized to estimate service lives based upon service lives used by other utilities for this class of plant as well as what might

be reasonable life for this plant giving consideration to the current age and use of the facilities.

MONTANA - DAKOTA UTILITIES

Common Plant

Study Results

Account 390.00 - General Structures

The Company's investment in this account totals $18,048,459 which is related to the Company's administrative structures within its operating system. The surviving investment has achieved a current average age of 15.5 years and is presently being depreciated based upon an annual depreciation rate of 3.76 percent.

An analysis of retirements totaling $5,708,004, which occurred during the period 1951-2001 were analyzed via the Simulated Plant Record Method, which produced an average service life in the range of 35 years. Accordingly, an Iowa 35-R3 life and curve was applied to the Company's surviving investment, which produced an average remaining life of 21.1 years.

While past retirements have generated positive salvage for two (2) recent years, most years within the analysis band produced varying levels of negative salvage. Future net salvage relative to the property contained in this account is estimated at negative ten (10) percent. The resulting annual depreciation rate is 2.93 percent.

Account 391.1 - Office Furniture and Equipment

The Company's investment in office furniture and fixtures totals $3,716,417, which has achieved a current average age of 12.7 years and is presently being depreciated utilizing an annual depreciation rate of 1.48 percent. Retirements totaling $2,716,404, which occurred during the 1932-2001 band, were analyzed via the Simulated Plant Record Method which produced a life indication in the range of twenty (20) to twenty-five (25)

years. However, due to the difficulty in tracking many relatively low cost investment it is believed the numerous items fail to be retired when no longer used in service, thereby resulting in significant levels of unrecorded retirements. Due to this scenario and the difficulty of properly tracking investments and related retirements an Iowa 15-R3 life and curve is estimated for the property class. Furthermore, it is proposed that the investment within this property group be amortized over a fifteen (15) year period. The resulting annual amortization rate is 4.95 percent

Account 391.3 - Computer Equipment - PC

The Company's current investment in this account totals $4,212,743, has attained a current average age of 3.4 years, and is presently being depreciated based upon an annual depreciation rate of 12.5 percent. Given the young age of the property group along with the likely under-reporting of retirements which have actually occurred to date, the achieved life indication relative to this property class is likely overstated. While an analysis of general data relative to PC computer type equipment, of which this property group is principally comprised, have general experienced an average service life in the range of seven (7) years there are various under utilized and/or likely un-retired items on the Company's books. Furthermore, and more importantly, recently the Company has increased its effort to stay more current with the technological advances inherent within this asset category. This effort is being driven by the continual need for increase processing power (due to software requirements, etc.) as well as the reduced cost of the newer equipment platforms. In general, it is widely known that this property class, which is significantly impacted by the technological advances, routinely requires a very high frequency of upgrades and/or replacements. Based upon this experience and future

expectation of ongoing rapid changes in future years an Iowa 5-R3 life and curve is estimated for this property which produces an average remaining life of 2.5 years. Future net salvage is estimated at zero (0) percent and the resulting depreciation rate is 23.29 percent.

Account 392.10 - Transportation Equipment-Trailers

The present surviving investment in this account totals $251,166 has attained a current average age of 14.5 years, and is presently being depreciated utilizing an annual depreciation rate of 5.74 percent. Retirements totaling $14,887, which occurred during the 1992-2001 experience band, were analyzed via the Simulated Plant Record Method and a life indication in the range of twenty (20) plus years. Accordingly, an average service life of an Iowa 20-L2 is estimated, based upon the life estimate for this property group. Application of the recommended life and curve to the Company's current surviving investment produces an average remaining life of 10.8 years.

Based upon Company experience and future expectations future net salvage is estimated at fifteen (15) percent.

In as much as the Company's current plant in service is presently fully accrued, flowing the estimated level of net salvage through the normal depreciation rate calculation would presently produce a negative depreciation rate. Based upon the expectation that the Company will be acquiring additional plant in this property category, the use of a negative deprecation is not warranted and /or rationale. Accordingly, it is recommended that the depreciation rate for this property group be set at zero (0) percent. Subsequent to the Company's addition of further plant in this property group and the reduction of the current level of deprecation reserve, a depreciation rate should be developed based upon

the above discussed depreciation parameters. Accordingly, the present annual depreciation rate is estimated at zero (0) percent.

Account 392.20 - Transportation Equipment - Cars & Trucks

The investment in this account totaling $4,429,702, which currently is depreciated utilizing an annual depreciation rate of 5.74 percent, has current attained an average age of 4.5 years.

Retirements totaling $15,861,531, which occurred during the period 1995-2001, were analyzed for the overall experience period, as well as the various other interim bands. This analysis shows that historically much of the Company's property in this account is routinely being replaced in the range if seven (7) years, resulting in a service life indication of six years or less. Based upon the Company's recent experience, an Iowa 7-R3 life and curve are recommended for this account. Application of the proposed service life parameters to the Company's current surviving investment produces an average remaining life of 3.5 years.

An analysis of the Company's retirements and related salvage during the period 1968-2001 indicates that the Company has received positive salvage relative to disposal of its automobiles in the past. The analysis identifies that the Company's average net salvage has averaged approximately twenty (20) plus percent salvage. Based upon the overall historic experience, future net salvage of twenty (20) percent was incorporated in developing the resulting depreciation rate for this property. Utilizing the estimated average service life and salvage factors together with the Company's current surviving investment produces an average remaining life depreciation rate of 13.33 percent.

Account 393 - Stores Equipment

The Company's investment in this account totals $47,386, has attained a current average age of 4.9 years, and is presently being depreciated utilizing an annual depreciation rate of 3.36 percent. The Company's investment in this account is somewhat limited and is related to general storeroom equipment located at the Company's various operations warehouses. Due to the limited investment level no retirements have occurred to date. An Iowa 30-R2 life and curve is estimated as the applicable service life.

An analysis of the Company's salvage experience was completed for the period 1968-2001 to identify the level of net salvage achieved with past retirements. The result of the analysis indicates that the Company has experienced only minimal net salvage. Based upon the Company's experience in many years, as well as general industry experience, future net salvage is estimated at zero (0) percent and the resulting annual amortization rate is 2.80 percent.

Account 394 - Tools, Shop and Garage Equipment

The investment in this account totaling $1,176,603 is related to tools, garage, and work equipment utilized by the Company's employees in providing service to the Company's customers. Accordingly, the Company maintains investment in this account within four (4) separate sub-account categories which include Tools, Shop & Garage Equipment - Non Utilized, Tools, Shop and Garage Equipment Utilized, Vehicle Maintenance Equipment and Vehicle Refueling Equipment. Based upon the content of each property group and the completed analysis the average service life parameters were estimated for each of the subcategory investments.

The Company's investment in Tools, Shop & Garage Equipment - Non Utilized,

totals $235,026. Retirements from the property group have totaled $3,075 over the life of the account which have produced of life indication in the range of twenty-five (25) years. However, given the difficulty in tracking the many items with smaller investment amounts it is likely that numerous items fail to be retired when no longer in service. Accordingly, due to this ongoing difficulty in attaining proper retirements a service life of an Iowa 18-R2 life and curve is estimated for this property group. Furthermore, it is proposed that the investment within this property group be amortized over a eighteen (18) year period.

The Company's investment in Vehicle Maintenance Equipment, totals $102,746. An Iowa 20-R3 life and curve is estimated as the applicable life of the property group. Accordingly, the recommended amortization period for the asset investments is twenty-five (25) years.

The Company's investment relative to Vehicle Refueling Equipment totals $838,830. Giving recognition to the property groups content and various analysis on Iowa 20-R3 life and curve is estimated for this property class. A twenty (20) year amortization period is proposed for this asset class.

The Company's vintage investment for each property category was applied to the applicable recommended service life and curve, recommended amortization and resulting implicit depreciation rates as summarized in the table below.

Account 394 - Tools, Shop and Garage Equipment

Acct. No.	Description	P-I-S 12-31-00	Curve	Amort. Rate Period	Net Rate %	Amort. Rate %
394.10	Tools, Shop & Garage Eq. Non-Utilized	$235,026	18-R2	18	0	6.11
394.30	Vehicle, Maintenance Equipment	102,746	20-R3	20	0	4.75

394.40	Vehicles Refueling Equipment	838,830	20-R3	20	0	4.38
	Total Equipment	$1,176,603				

Account 396.20 - Power Operated Equipment

The Company's current investment in this account totals $157,573, which is currently being depreciated utilizing an annual depreciation rate of 4.83 percent. The property investment, which has attained a current average age of 11.3 years. Retirements during the recent history of the account totaling $6,083, were analyzed via the Simulated Plant Record Method. The analysis of the data provided a general life indication of ten (10) years. Accordingly, an average service life of an Iowa 10-R2 is recommended for this property group giving consideration to general industry lives.

The Company's available historical salvage data was analyzed during the period 1968 -2001. This analysis indicates that during the period studied the Company has achieved average net salvage of approximately forty-nine (49) percent. However, the actual level of achieved net salvage is somewhat overstated due to the past accounting treatment of the trade-ins. That is, historically the trade-in amounts have been identified and recorded based upon the value allowed against the full retail price of the newly purchased asset as opposed to the actually lower level trade-in in price against the normal market price for the purchased equipment. While the net purchase price is the same under either scenario, the Company's historical accounting treatment of the trade-ins results in an over statement of the net salvage being received for the traded equipment. Accordingly, based upon this analysis future net salvage for this asset class is estimated at forty (40) percent and when combined with the recommended service life parameters in the current investment produces an average remaining life depreciation rate of 2.69 percent.

Account 397 Communication Equipment

The Company's maintains its investment in this account in five (5) categories of communication equipment, namely Fixed Radio Equipment, Radio Equipment Mobile, Telephone, Supervisory and Telemetering Equipment, and Networking Equipment. An analysis was performed using various reports, as well as other company data sources, to identify the investment levels for each equipment group.

The Company's current investment in Radio Communication Equipment - Fixed totals only $646,187 for which the current depreciation rate is 4.33 percent. While the general historical analysis produces a life in the range of twenty (20) plus years ongoing changes are occurring with technology. Accordingly, based upon the property group an Iowa 15-R3 life and curve is estimated relative to this investment and is the basis of the recommended amortization period for this property group. Application of the estimated service life parameters to the current surviving investment produces a current implicit amortization rate of 4.99 percent.

The Company investment in Radio Communication Equipment Mobile totals $1,285,023 and is currently being depreciated at an annual rate of 6.68 percent. While an analysis of the historical data in this property group produced a life indication in the range of twenty (20) years, a service life of fifteen (15) years is estimated for this property group based upon the rapidly changing technology and operating practices. Accordingly, amortization period of the estimated 15 year period produces a current implicit amortization rate of negative 4.08 percent.

The remaining investment relative to General Telephone Communication Equipment totals only $779,821. Notwithstanding the overall life indication of approximately fifteen (15) years an Iowa 10-R2life and curve is estimated for this property class based upon the

changing technology and general industrial information. The resulting proposed implicit amortization rate is 8.72 percent.

The Company's investment in Supervisory and Telemetering Equipment totals only $48,296. An Iowa 15-L1 life and curve is estimated as the applicable service life characteristics. The resulting implicit amortization rate is 0.35 percent.

The Company's investment in Networking Equipment totals $824,948. Giving recognition to the equipment type within the property group (which is similar to computer type equipment), an Iowa 5-R3 life and curve is estimated for this class of property. The resulting implicit annual amortization rate is 17.95 percent.

The Company's vintage investments for each property category, the applicable recommended service life parameters and recommended implicit amortization rates are summarized in the table below.

Account 397 - Communication Equipment

Acct. No.	Description	P-I-S 12-31-01	ASL/ Curve	Amort. Period (Yrs.)	Net Salv. %	Amort. Rate %
397.10	Radio Communication Equipment (fixed)	$646,187	15-R3	15	-10	4.99
397.20	Radio Communication Equipment (mobile)	1,285,023	15-R3	15	0	4.08
397.30	General Telephone Communication Eq.	779,821	10-R2	10	10	8.72
397.50	Supervisory & Telemetering Equipment	48,296	15-L1	15	0	0.35
397.80	Networking Equipment	824,948	5-R3	5	0	17.95
	Total Equipment	$3,584,275				

Account 398 - Miscellaneous Equipment

The present surviving investment in this account totals $592,895, has attained a

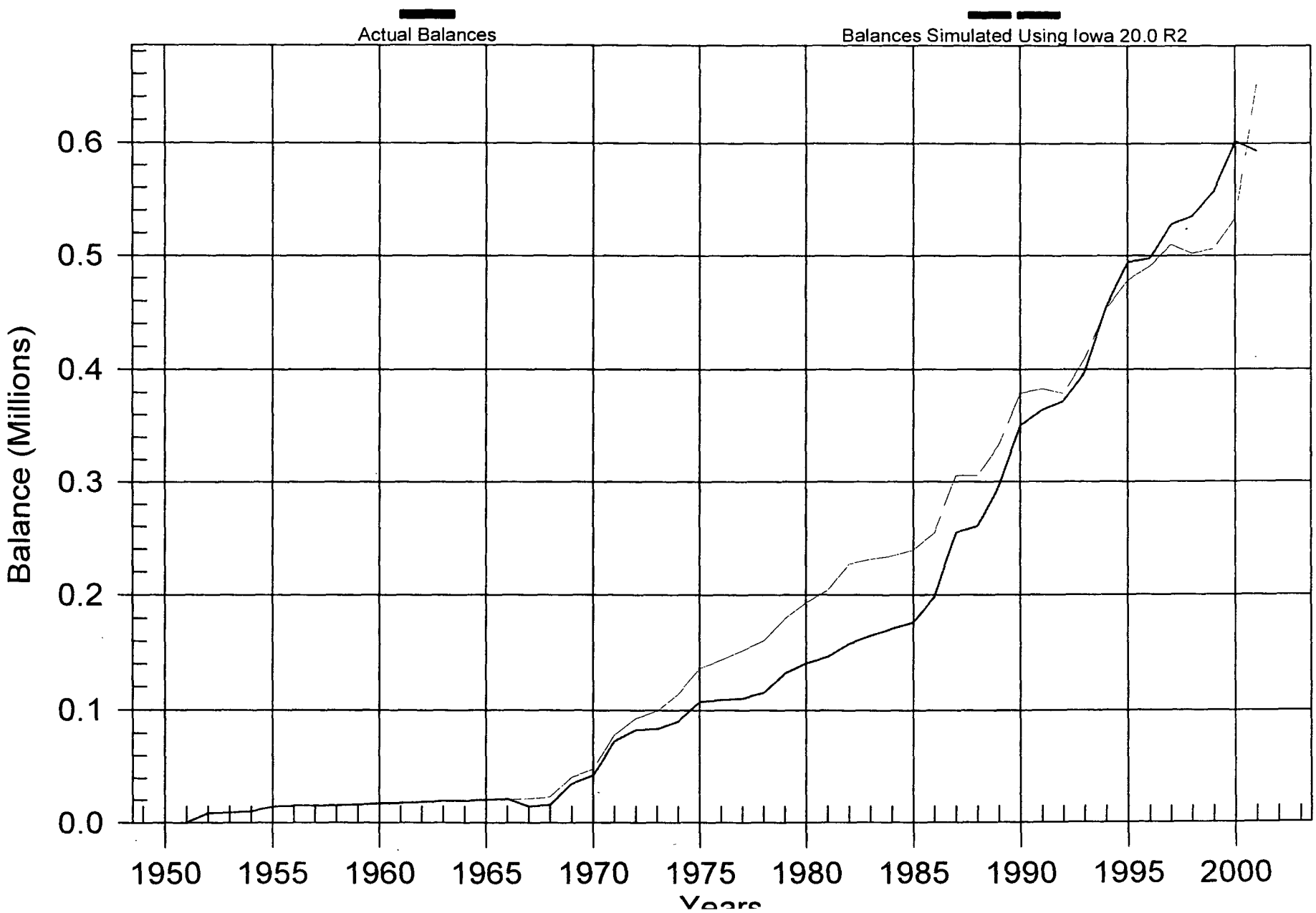
current average age of 8.2 years, and is presently being depreciated utilizing an annual depreciation rate of 2.51 percent. Retirements totaling $319,929, which occurred during the years 1919-2000, were analyzed via the Simulated Plant Record Method. Based upon this analysis, consideration of the general account content, related under reporting of plant assets, and general industry data an average service life of twenty (20) years is estimated for the asset group. Based upon an estimated life and curve relative to the Company's current surviving investment of an Iowa 20-R2 the current implicit annual amortization rate for this property group is 2.41 percent.

Montana-Dakota Utilities Company

Common Plant

398.00 MISCELLANEOUS EQUIPMENT

Actual And Simulated Balances

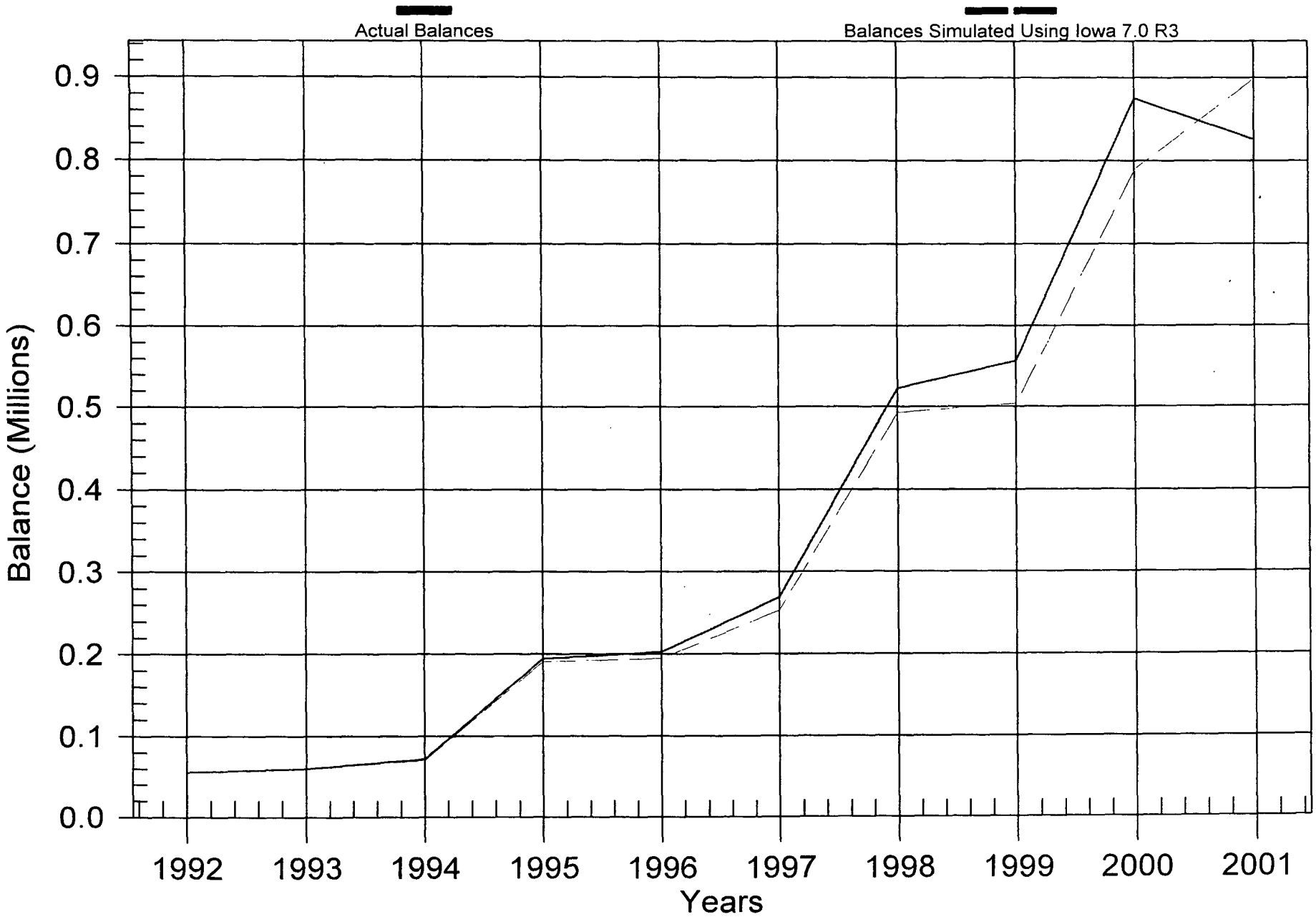


Montana-Dakota Utilities Company

Common Plant

397.80 NETWORK EQUIPMENT

Actual And Simulated Balances

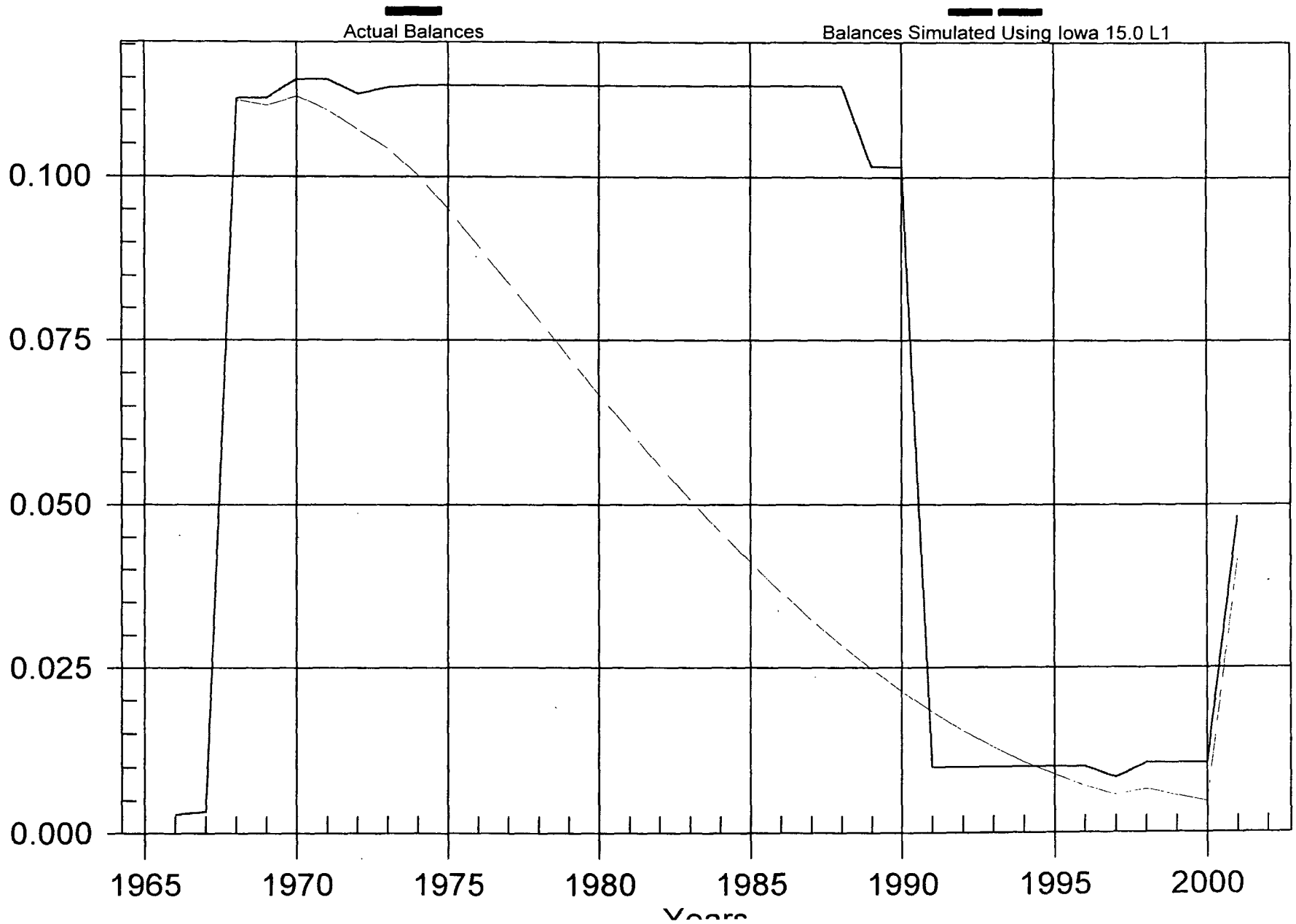


Montana-Dakota Utilities Company

Common Plant

397.50 SUPERVISORY & TELEMETERING EQUIP.

Actual And Simulated Balances

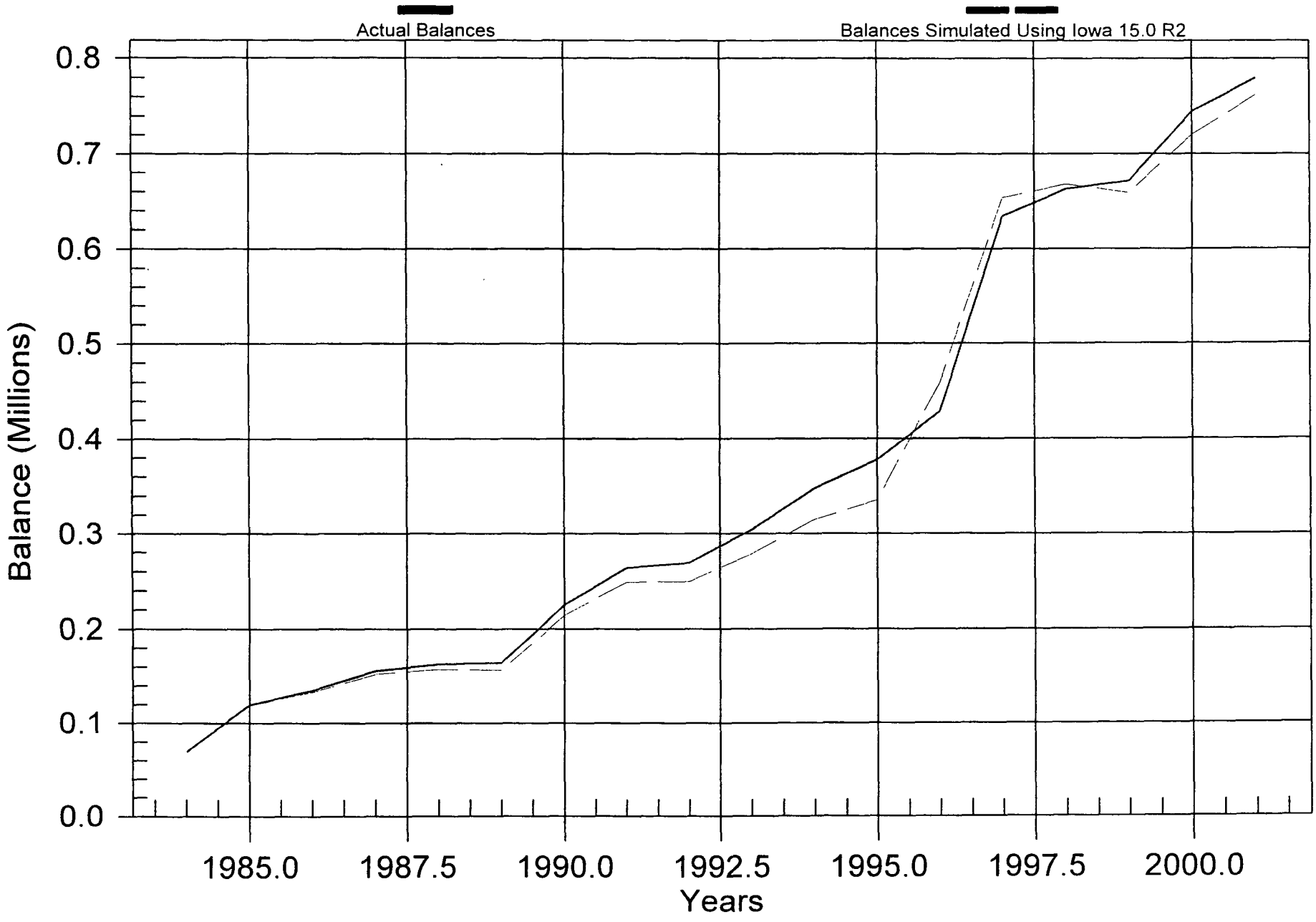


Montana-Dakota Utilities Company

Common Plant

397.30 TELEPHONE COMMUNICATION EQUIP.

Actual And Simulated Balances

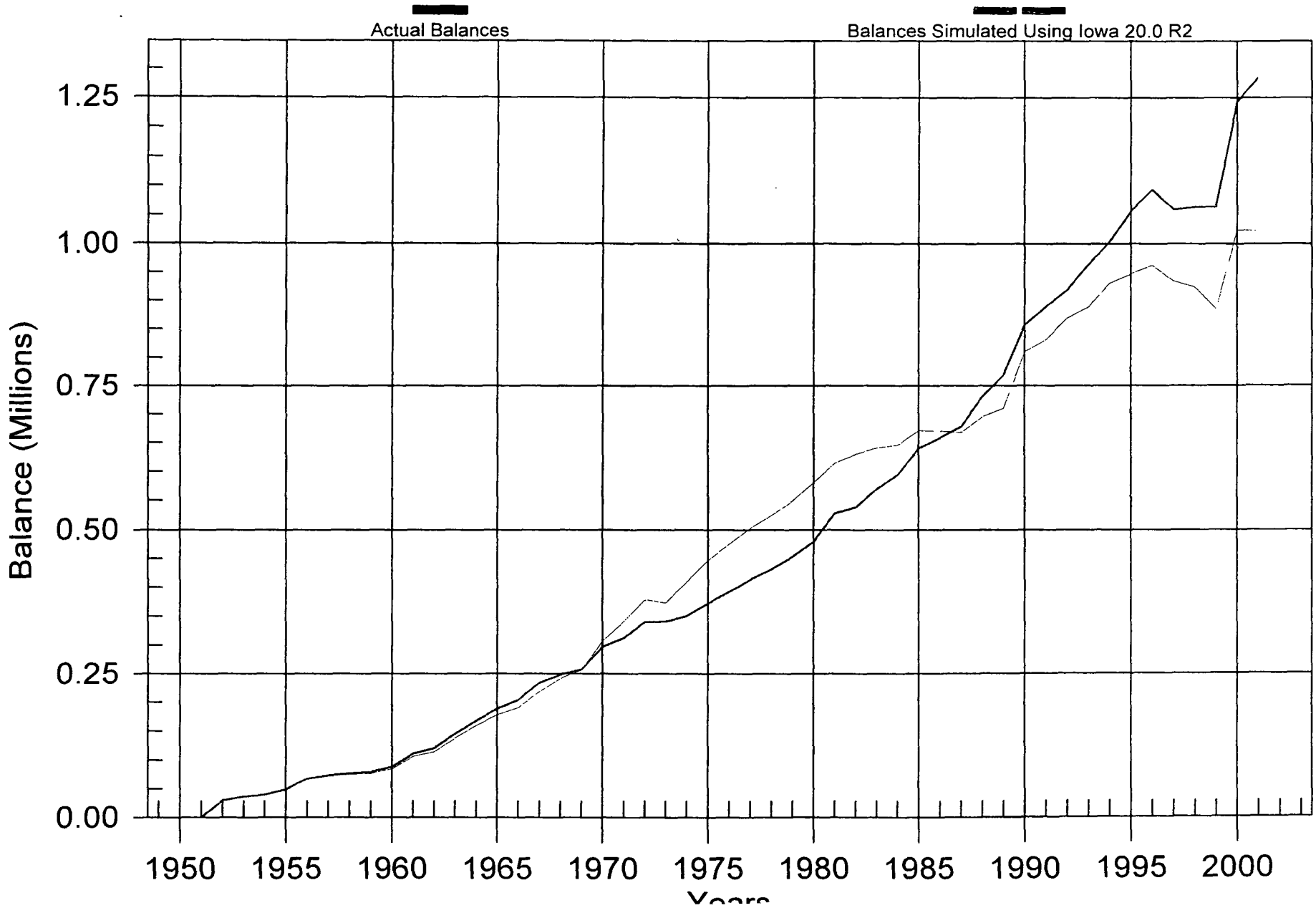


Montana-Dakota Utilities Company

Common Plant

397.20 COMMUNICATION EQUIP. - MOBILE RADIOS

Actual And Simulated Balances

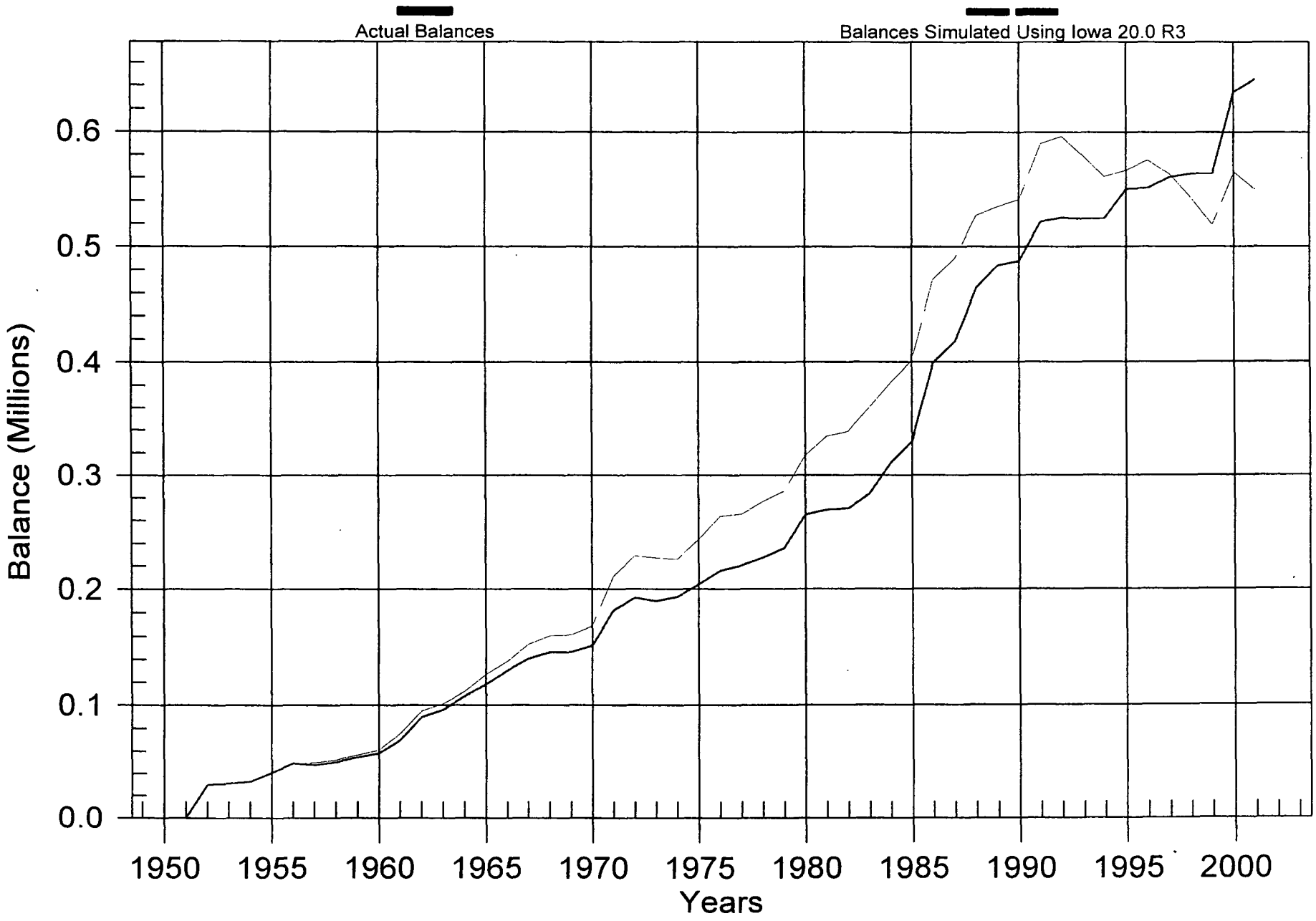


Montana-Dakota Utilities Company

Common Plant

397.10 COMMUNICATION EQUIP. - FIXED RADIOS

Actual And Simulated Balances



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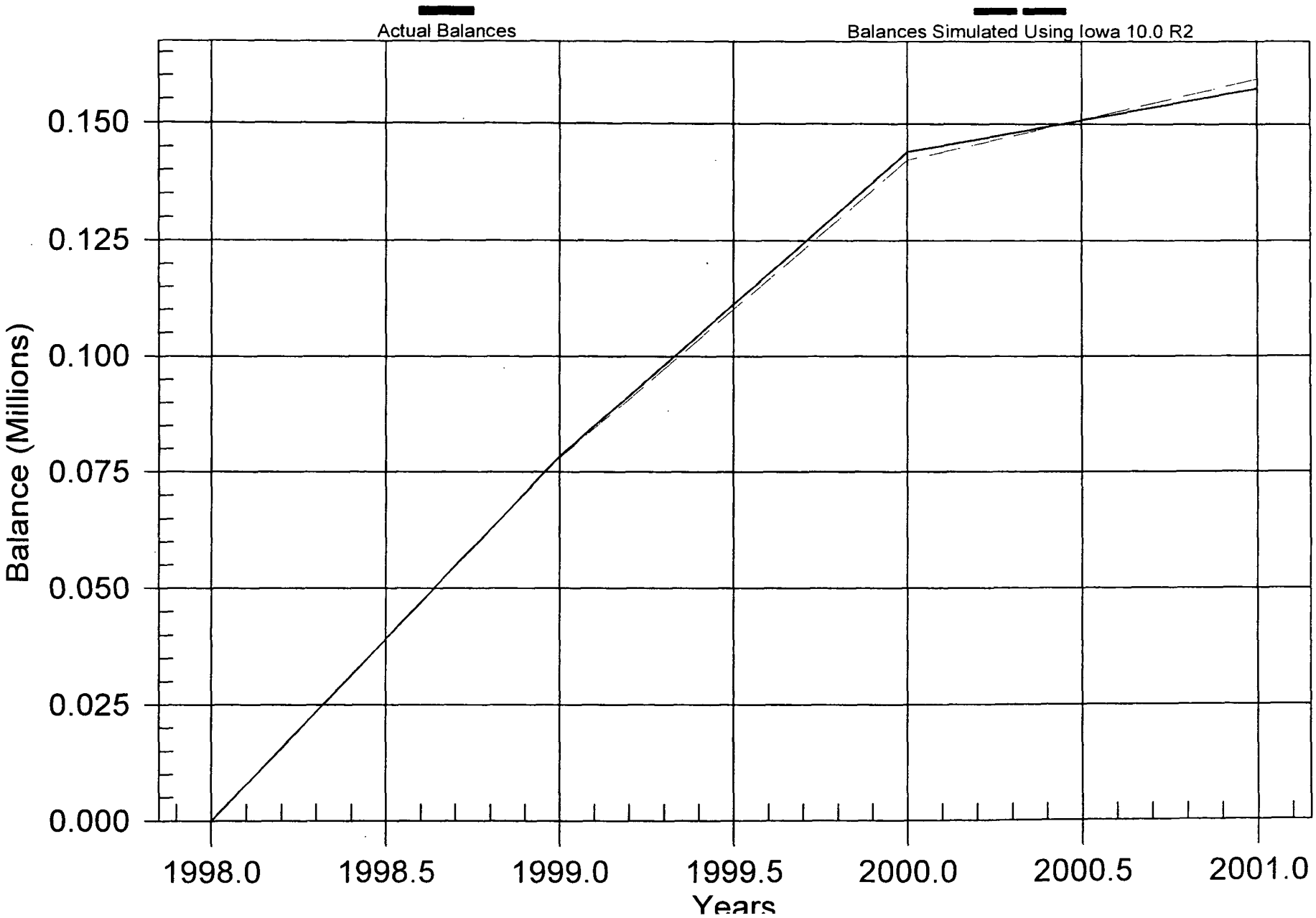
Montana-Dakota Utilities Company

Common Plant

396.20 POWER OPERATED EQUIPMENT

Actual And Simulated Balances

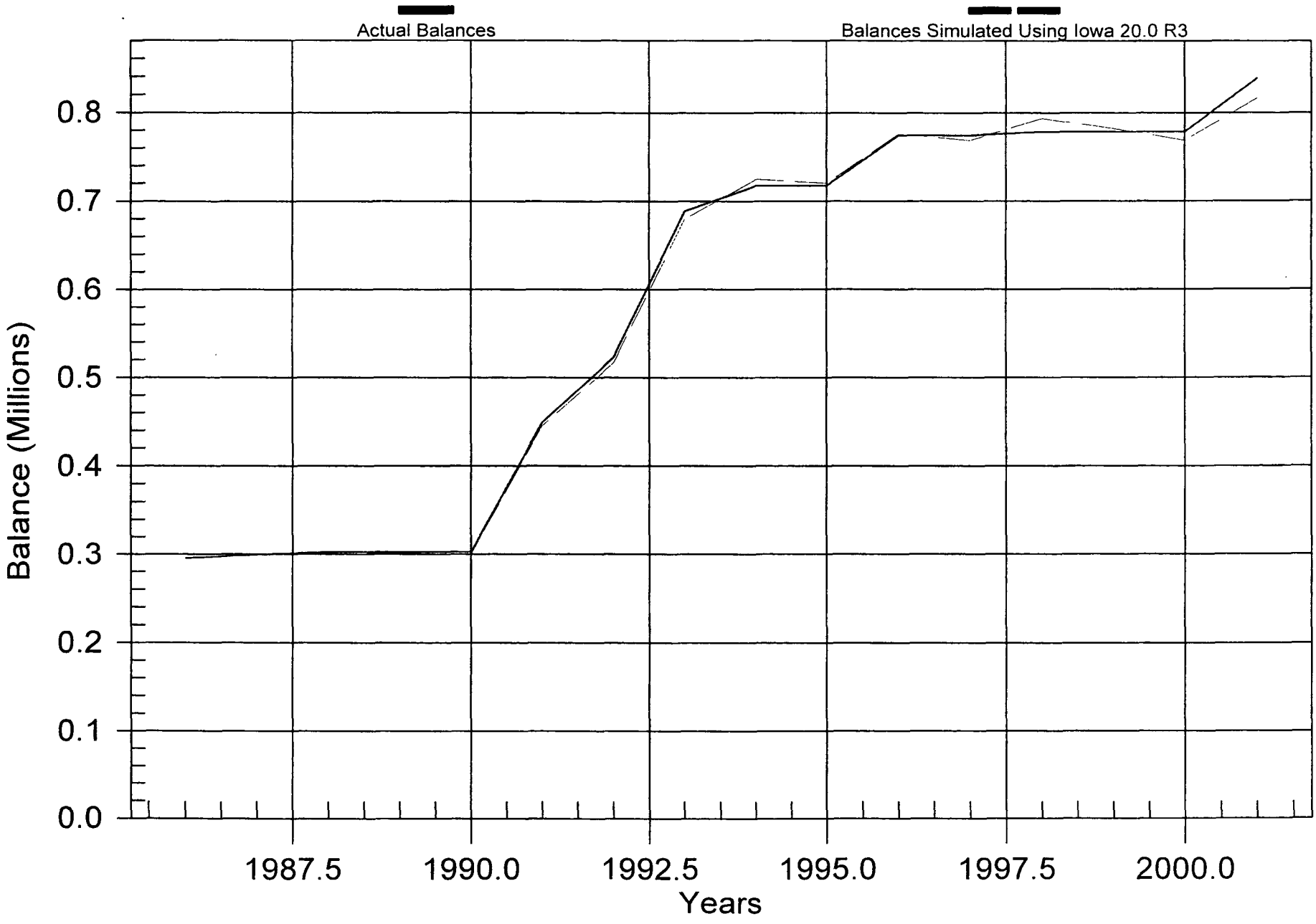


Montana-Dakota Utilities Company

Common Plant

394.40 VEHICLE REFUELING EQUIPMENT

Actual And Simulated Balances

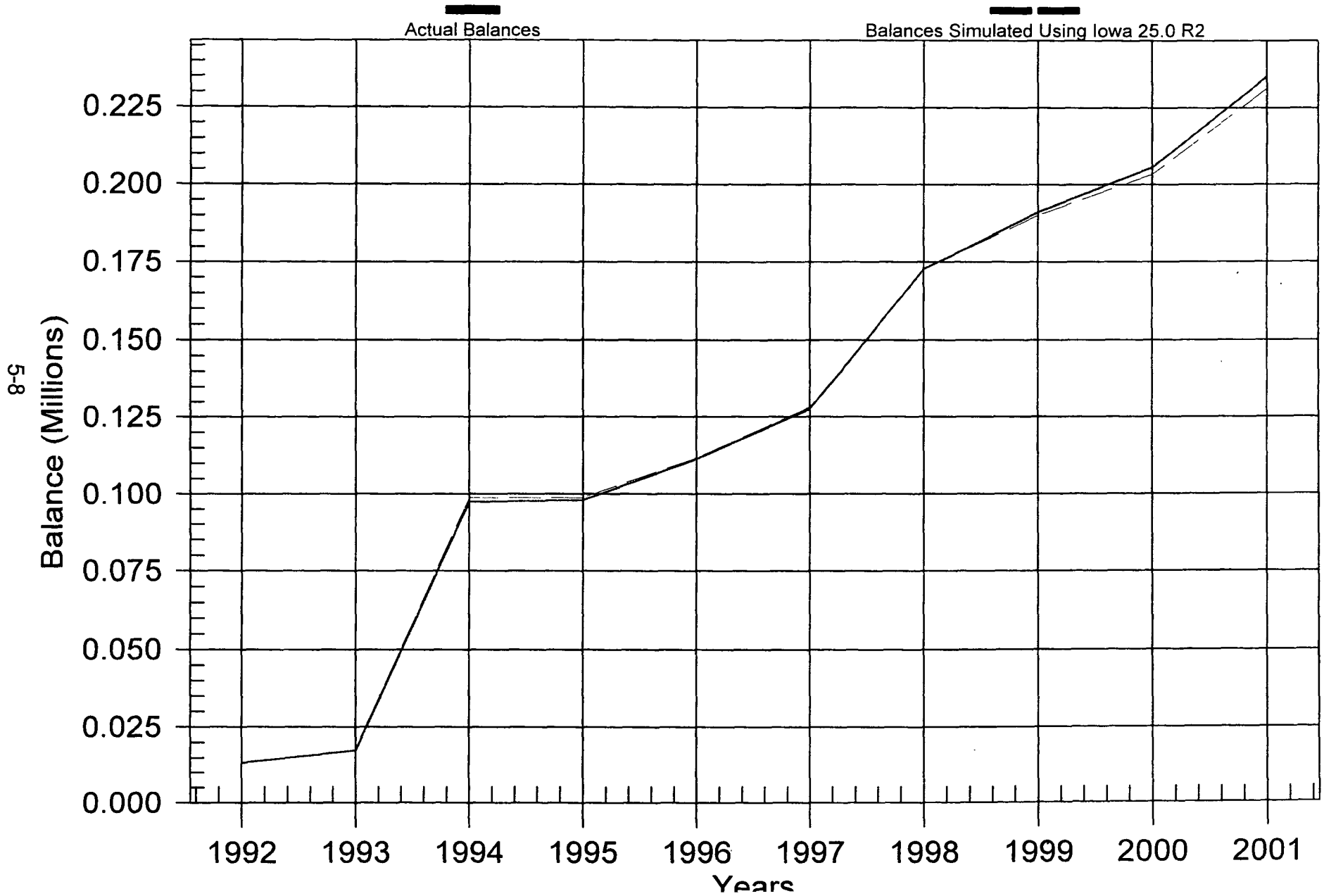


Montana-Dakota Utilities Company

Common Plant

394.10 TOOLS, SHOP & GARAGE EQ. - (NON-UNITIZED)

Actual And Simulated Balances

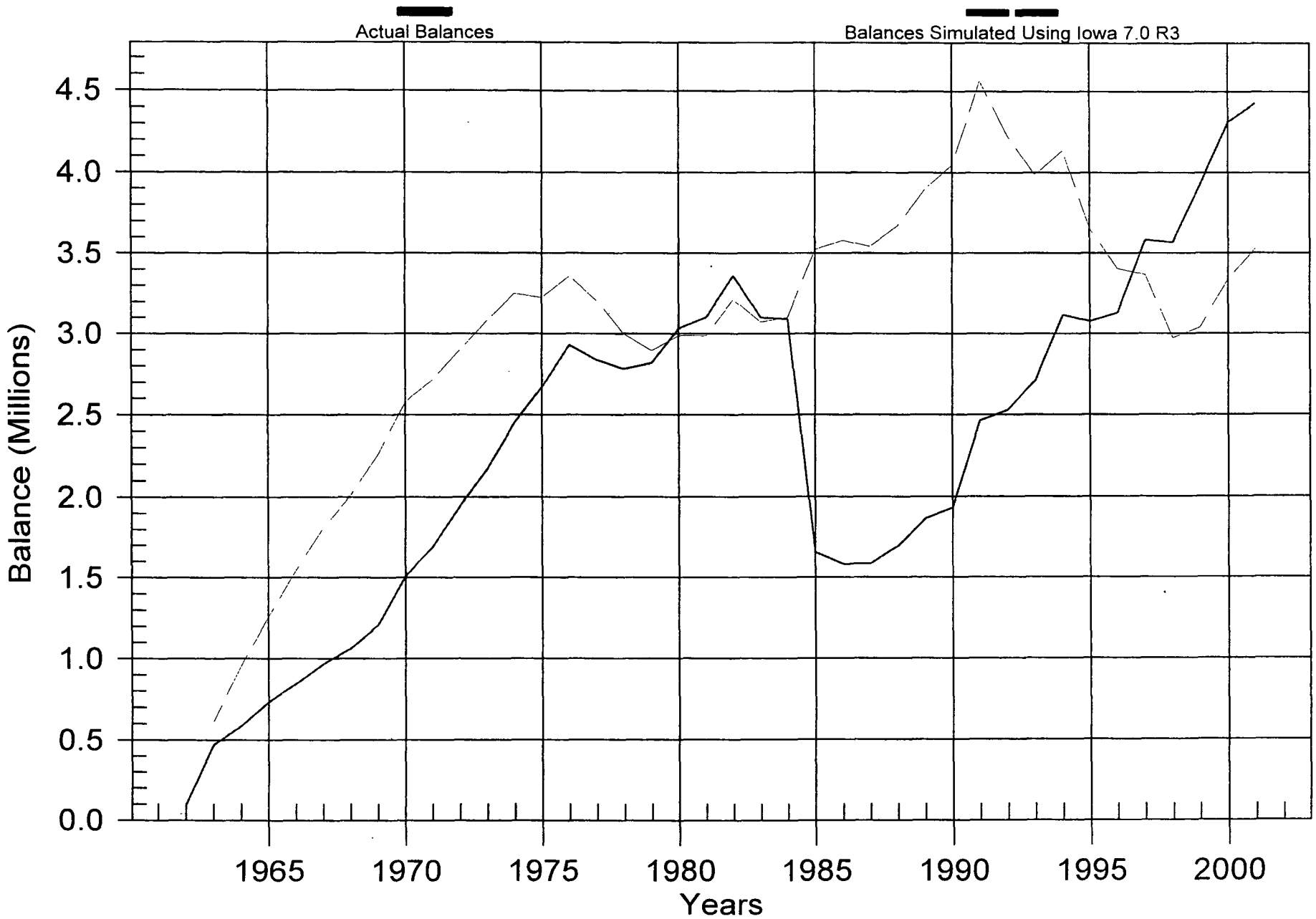


Montana-Dakota Utilities Company

Common Plant

392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)

Actual And Simulated Balances

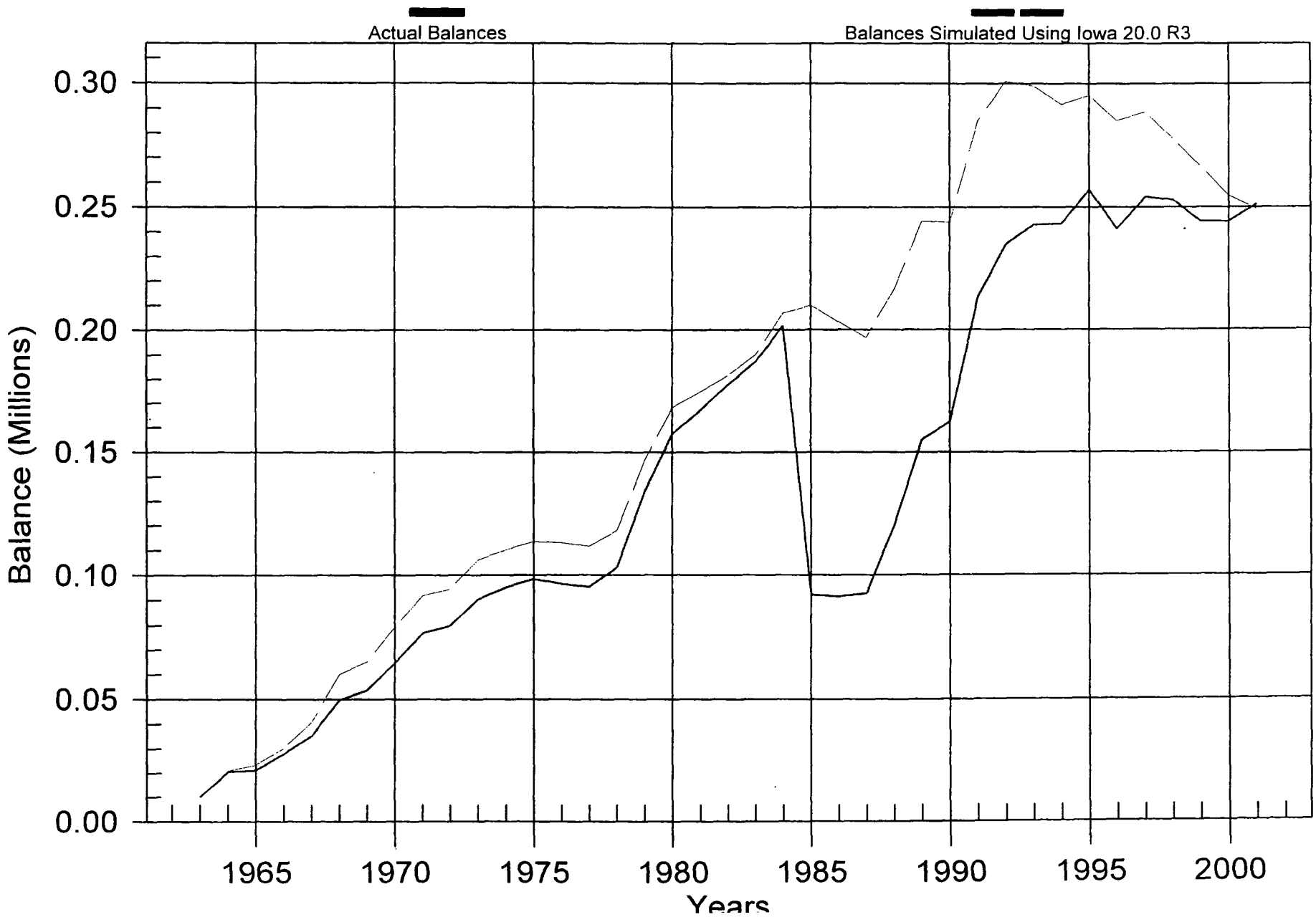


Montana-Dakota Utilities Company

Common Plant

392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)

Actual And Simulated Balances

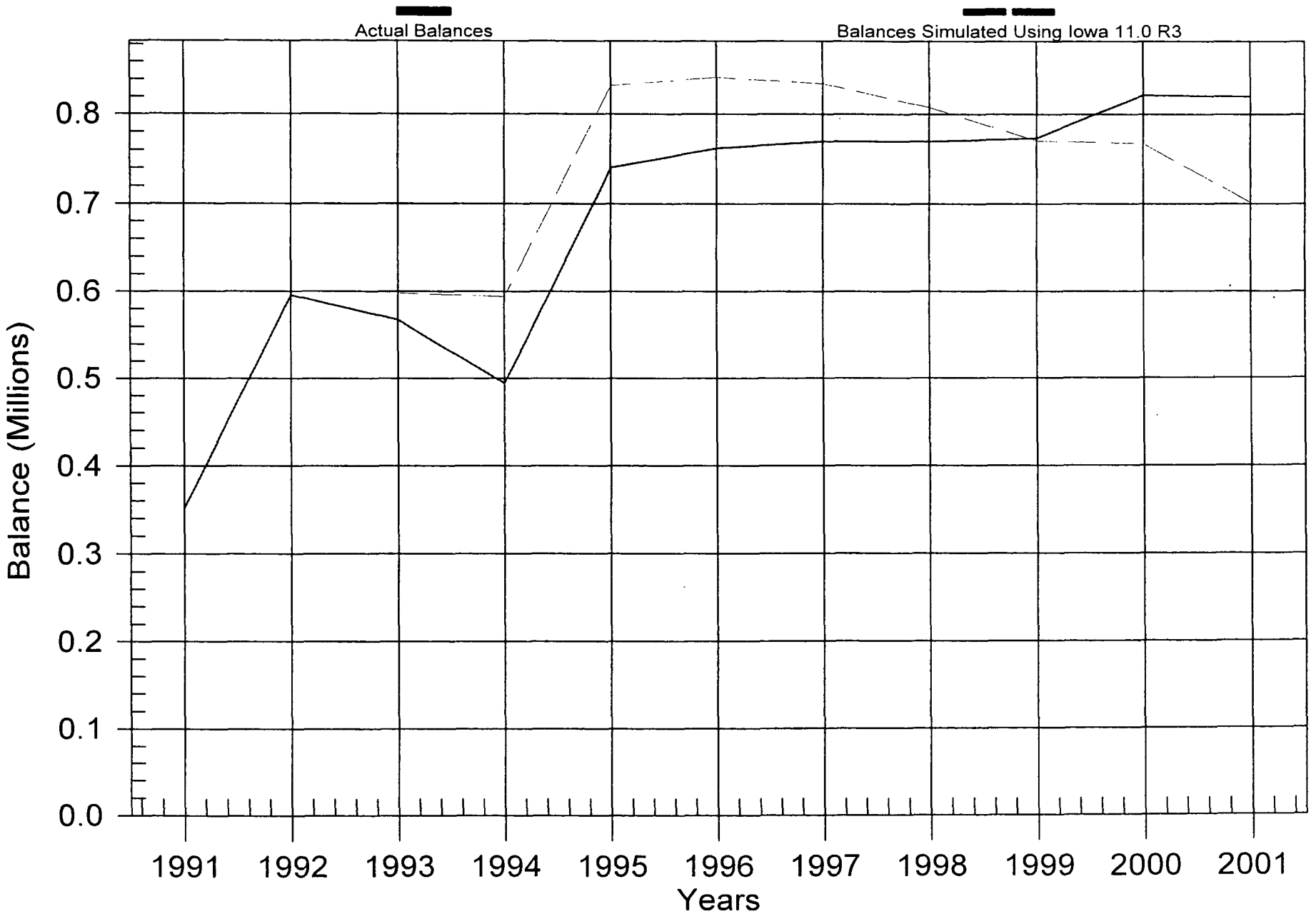


Montana-Dakota Utilities Company

Common Plant

391.50 COMPUTER EQUIPMENT - OTHER

Actual And Simulated Balances

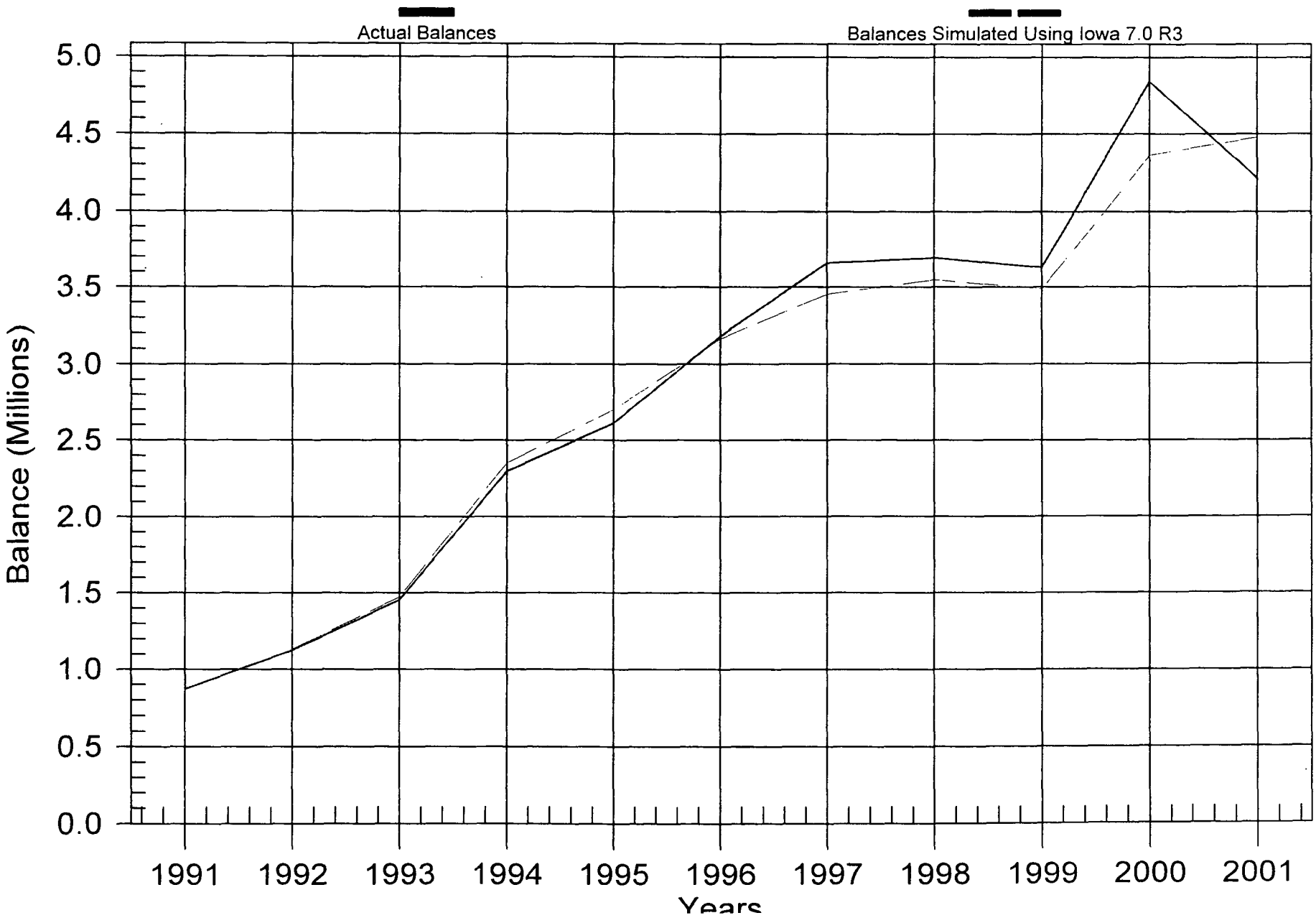


Montana-Dakota Utilities Company

Common Plant

391.30 COMPUTER EQUIPMENT - PC

Actual And Simulated Balances

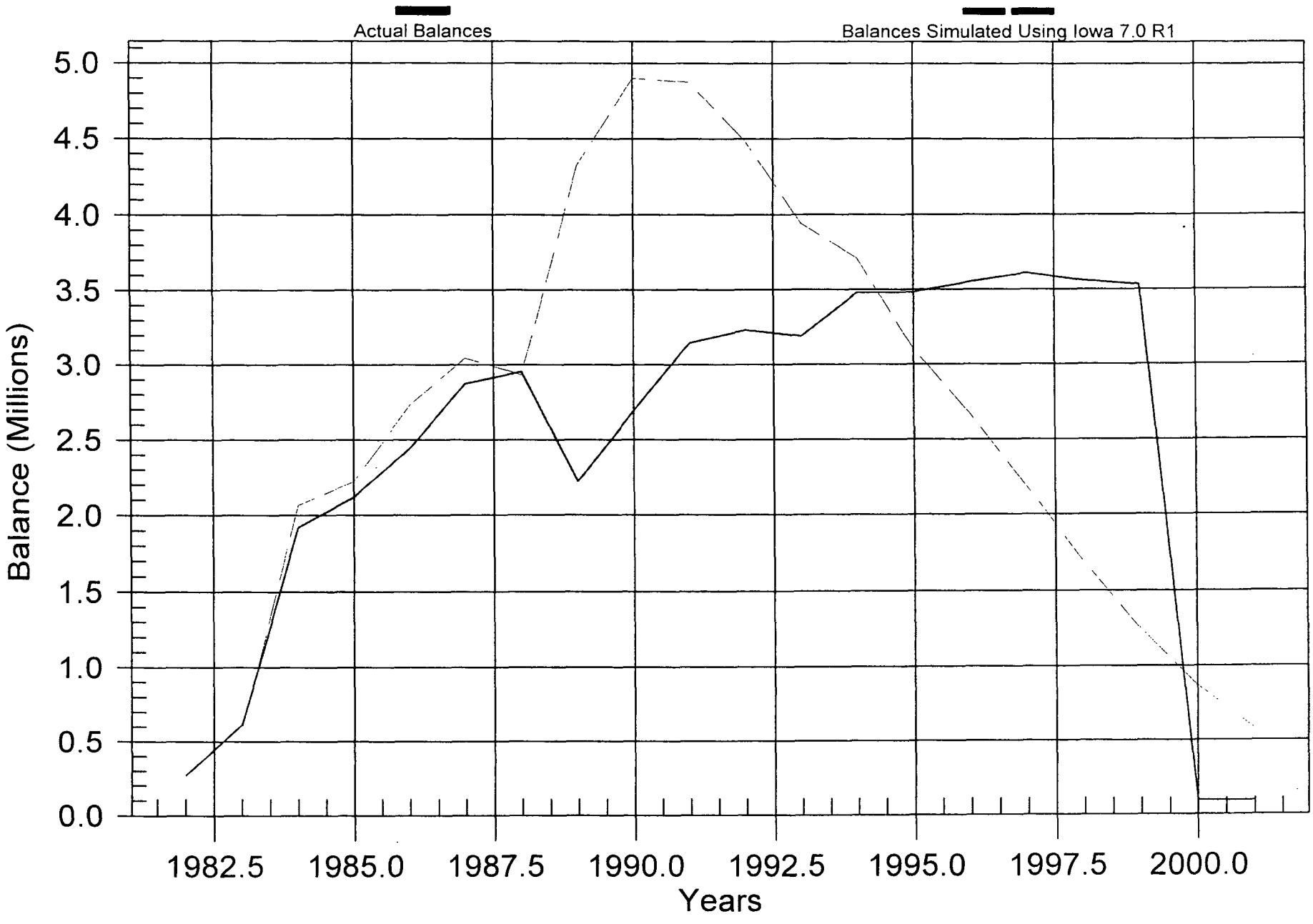


Montana-Dakota Utilities Company

Common Plant

391.20 COMPUTER EQUIPMENT- HONEYWELL

Actual And Simulated Balances

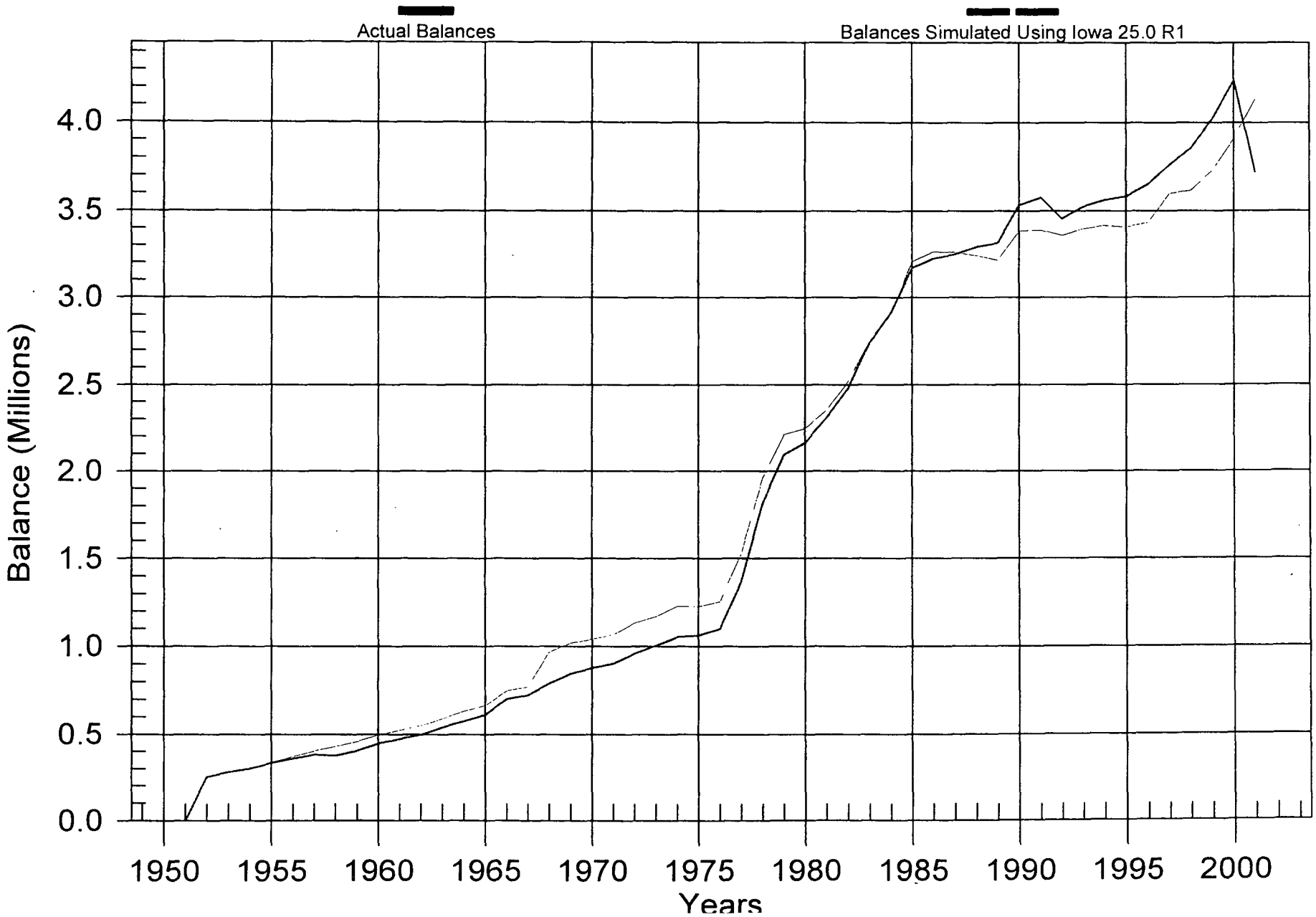


Montana-Dakota Utilities Company

Common Plant

391.10 OFFICE FURNITURE & EQUIPMENT

Actual And Simulated Balances

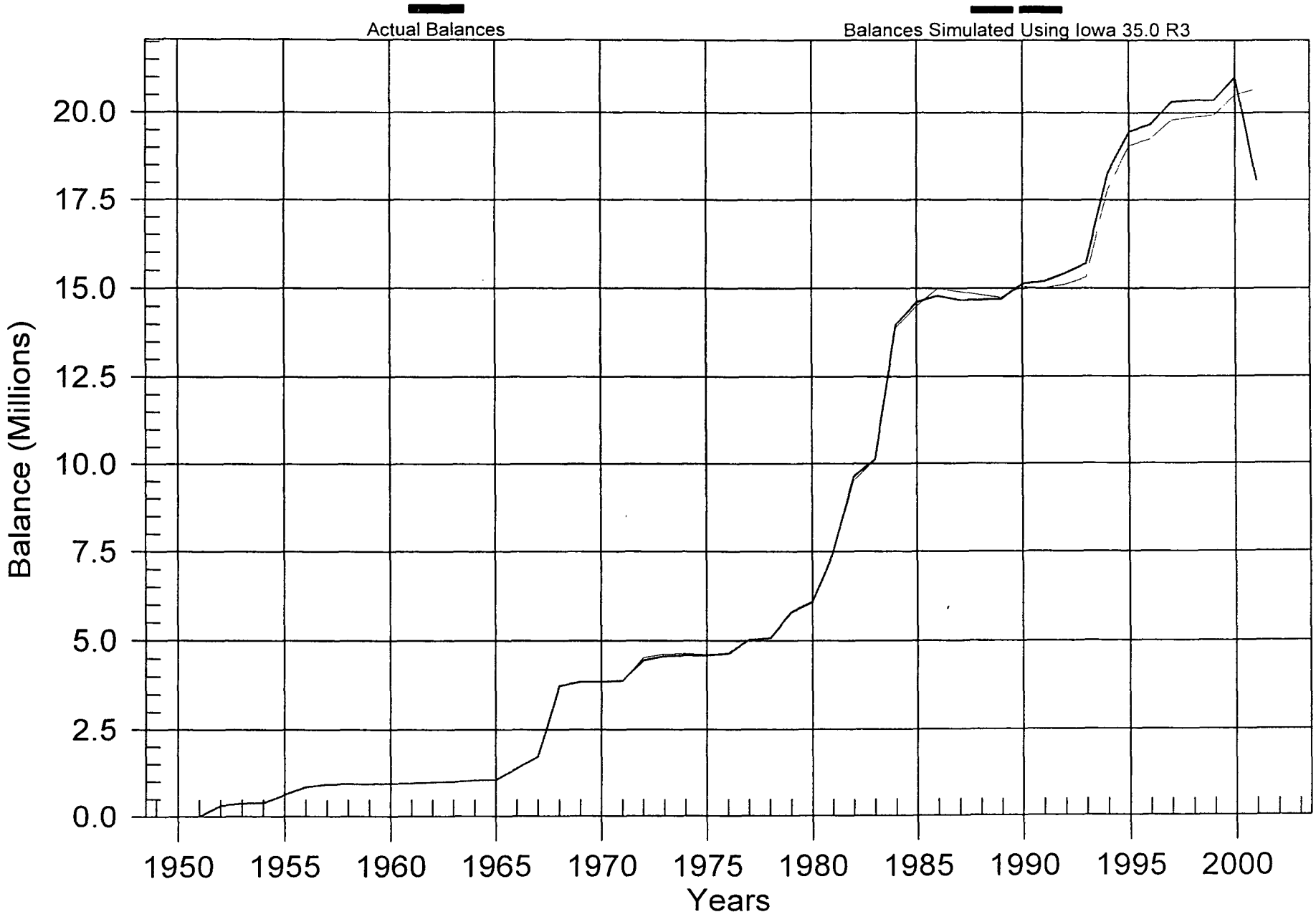


Montana-Dakota Utilities Company

Common Plant

390.00 STRUCTURES & IMPROVEMENTS

Actual And Simulated Balances



Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1952	12,250.98	35.00	350.03	2.40	838.53
1953	3,494.96	35.00	99.86	2.66	265.36
1954	863.89	35.00	24.68	2.91	71.82
1955	21,585.22	35.00	616.72	3.16	1,951.89
1956	24,602.68	35.00	702.93	3.42	2,407.30
1957	11,218.58	35.00	320.53	3.69	1,183.10
1958	1,338.02	35.00	38.23	3.97	151.65
1959	413.04	35.00	11.80	4.26	50.22
1960	2,078.30	35.00	59.38	4.56	270.83
1961	2,128.68	35.00	60.82	4.88	296.89
1962	9,611.94	35.00	274.63	5.22	1,434.47
1963	5,458.13	35.00	155.95	5.59	871.47
1964	18,983.94	35.00	542.40	5.98	3,242.38
1965	3,850.31	35.00	110.01	6.39	703.32
1966	152,339.84	35.00	4,352.56	6.84	29,751.18
1967	172,216.55	35.00	4,920.47	7.30	35,935.66
1968	1,078,623.93	35.00	30,817.81	7.80	240,382.73
1969	74,566.26	35.00	2,130.46	8.32	17,734.17
1970	5,744.59	35.00	164.13	8.87	1,456.61
1971	18,619.63	35.00	531.99	9.45	5,027.84
1972	424,523.66	35.00	12,129.24	10.05	121,926.41
1973	78,064.41	35.00	2,230.41	10.68	23,814.78
1974	16,413.39	35.00	468.95	11.32	5,310.16
1976	42,369.12	35.00	1,210.55	12.68	15,353.82
1977	307,620.90	35.00	8,789.16	13.39	117,710.56
1978	36,373.62	35.00	1,039.25	14.12	14,674.39
1979	566,069.32	35.00	16,173.40	14.87	240,420.05

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1980	252,849.46	35.00	7,224.27	15.63	112,891.55
1981	1,089,627.23	35.00	31,132.19	16.40	510,664.35
1982	1,760,325.82	35.00	50,294.99	17.20	864,903.52
1983	530,875.31	35.00	15,167.86	18.01	273,097.42
1984	3,173,838.24	35.00	90,681.04	18.83	1,707,327.89
1985	555,190.04	35.00	15,862.56	19.66	311,932.03
1986	473,341.01	35.00	13,524.02	20.52	277,446.06
1988	4,844.35	35.00	138.41	22.25	3,080.15
1989	26,601.63	35.00	760.05	23.14	17,589.24
1990	354,395.87	35.00	10,125.59	24.04	243,442.72
1991	71,112.79	35.00	2,031.79	24.95	50,699.65
1992	201,647.50	35.00	5,761.35	25.87	149,070.38
1993	301,888.43	35.00	8,625.38	26.80	231,201.10
1994	2,295,728.36	35.00	65,592.20	27.74	1,819,798.53
1995	1,242,406.73	35.00	35,497.31	28.69	1,018,458.78
1996	328,408.43	35.00	9,383.09	29.65	278,173.49
1997	658,756.94	35.00	18,821.62	30.61	576,091.84
1998	262,526.48	35.00	7,500.75	31.58	236,841.33
1999	261,325.27	35.00	7,466.43	32.55	243,022.26
2000	721,289.40	35.00	20,608.26	33.53	690,917.72
2001	390,056.12	35.00	11,144.45	34.51	384,571.81
Total	18,048,459.30	35.00	515,669.96	21.11	10,884,459.40

Composite Average Remaining Life ... 21.11 Years

Montana-Dakota Utilities Company
Common Plant
391.30 COMPUTER EQUIPMENT - PC
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 5 *Survivor Curve:* R3

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1991	12,038.11	0.00	0.00	0.00	0.00
1992	20,462.65	0.00	0.00	0.00	0.00
1993	76,281.79	0.00	0.00	0.00	0.00
1994	379,244.26	5.00	75,840.37	0.50	37,920.18
1995	251,953.66	5.00	50,385.10	0.61	30,915.43
1996	441,976.73	5.00	88,385.46	0.86	76,300.24
1997	421,693.74	5.00	84,329.31	1.30	109,298.66
1998	376,604.59	5.00	75,312.49	1.93	144,999.75
1999	342,212.19	5.00	68,434.78	2.69	184,426.97
2000	1,278,689.70	5.00	255,709.34	3.57	912,048.91
2001	611,585.74	5.00	122,303.47	4.51	551,764.38
Total	4,212,743.16	3.64	820,700.32	2.50	2,047,674.52

Composite Average Remaining Life ... 2.50 *Years*

Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20 *Survivor Curve: L2*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1963	640.17	20.00	32.01	3.42	109.57
1964	840.93	20.00	42.05	3.63	152.51
1965	216.05	20.00	10.80	3.84	41.49
1966	700.52	20.00	35.03	4.05	141.97
1967	1,251.86	20.00	62.59	4.28	267.60
1968	2,588.83	20.00	129.44	4.50	582.23
1969	822.23	20.00	41.11	4.73	194.44
1970	2,495.80	20.00	124.79	4.96	619.29
1971	2,437.79	20.00	121.89	5.20	634.28
1972	688.04	20.00	34.40	5.45	187.36
1973	3,029.27	20.00	151.46	5.70	862.63
1974	1,324.65	20.00	66.23	5.94	393.71
1975	1,315.30	20.00	65.76	6.20	407.56
1976	269.34	20.00	13.47	6.45	86.83
1978	3,526.04	20.00	176.30	6.95	1,224.51
1979	14,765.19	20.00	738.26	7.19	5,308.89
1980	12,648.92	20.00	632.44	7.43	4,699.87
1981	5,621.98	20.00	281.10	7.67	2,156.22
1982	6,651.63	20.00	332.58	7.91	2,630.89
1983	8,407.10	20.00	420.35	8.16	3,428.09
1984	15,386.54	20.00	769.32	8.41	6,468.25
1985	6,583.86	20.00	329.19	8.68	2,856.35
1987	910.82	20.00	45.54	9.29	423.17
1988	21,673.27	20.00	1,083.66	9.66	10,465.18
1989	29,308.86	20.00	1,465.44	10.07	14,759.28
1990	6,921.80	20.00	346.09	10.55	3,650.51
1991	41,547.06	20.00	2,077.34	11.09	23,036.94

Montana-Dakota Utilities Company

Common Plant

392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20 *Survivor Curve: L2*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	20,869.81	20.00	1,043.49	11.71	12,217.02
1993	6,531.90	20.00	326.59	12.40	4,048.70
1994	2,053.77	20.00	102.69	13.16	1,350.91
1995	11,324.80	20.00	566.24	13.96	7,906.45
1997	11,785.47	20.00	589.27	15.68	9,242.41
2001	6,026.26	20.00	301.31	19.50	5,875.67
Total	251,165.86	20.00	12,558.23	10.07	126,430.76

Composite Average Remaining Life ... 10.07 Years

Montana-Dakota Utilities Company

Common Plant

392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 7 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1987	360.89	0.00	0.00	0.00	0.00
1988	8,875.57	0.00	0.00	0.00	0.00
1989	43,073.95	0.00	0.00	0.00	0.00
1990	98,778.54	7.00	14,110.54	0.50	7,055.27
1991	299,422.76	7.00	42,772.61	0.51	21,893.55
1992	90,643.81	7.00	12,948.49	0.68	8,860.24
1993	195,698.56	7.00	27,955.58	0.92	25,653.92
1994	533,479.40	7.00	76,207.65	1.24	94,182.07
1995	88,185.63	7.00	12,597.34	1.69	21,252.89
1996	322,941.29	7.00	46,132.24	2.28	105,033.12
1997	553,213.72	7.00	79,026.71	2.98	235,478.75
1998	214,015.43	7.00	30,572.15	3.77	115,233.62
1999	609,570.09	7.00	87,077.23	4.63	403,198.54
2000	761,724.81	7.00	108,812.56	5.55	603,877.63
2001	609,717.12	7.00	87,098.23	6.51	567,017.65
Total	4,429,701.57	5.60	625,311.32	3.53	2,208,737.27

Composite Average Remaining Life ... 3.53 Years

Montana-Dakota Utilities Company

Common Plant

396.20 POWER OPERATED EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 10 *Survivor Curve: R2*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1999	74,599.56	10.00	7,459.28	7.82	58,333.65
2000	63,626.84	10.00	6,362.11	8.67	55,162.91
2001	19,346.21	10.00	1,934.45	9.55	18,475.26
Total	157,572.61	10.00	15,755.83	8.38	131,971.82

Composite Average Remaining Life ... 8.38 Years

Montana-Dakota Utilities Company

Common Plant

391.10 OFFICE FURNITURE & EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *5%* *Average Service Life:* *15* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1960	1.50	0.00	0.00	0.95000	1
1961	19.09	0.00	0.00	0.95000	18
1962	75.13	0.00	0.00	0.95000	71
1963	292.85	0.00	0.00	0.95000	278
1964	651.45	0.00	0.00	0.95000	619
1965	1,016.06	0.00	0.00	0.95000	965
1966	3,458.20	0.00	0.00	0.95000	3,285
1967	1,938.70	0.00	0.00	0.95000	1,842
1968	17,011.43	0.00	0.00	0.95000	16,161
1969	7,725.44	0.00	0.00	0.95000	7,339
1970	5,866.63	0.00	0.00	0.95000	5,573
1971	8,698.41	0.00	0.00	0.95000	8,263
1972	20,989.14	0.00	0.00	0.95000	19,940
1973	17,250.80	0.00	0.00	0.95000	16,388
1974	28,368.26	0.00	0.00	0.95000	26,950
1975	9,446.11	0.00	0.00	0.95000	8,974
1976	25,929.59	0.00	0.00	0.95000	24,633
1977	148,440.80	0.50	15.00	0.91833	136,318
1978	253,109.68	0.58	15.00	0.91302	231,094
1979	168,472.49	0.78	15.00	0.90091	151,779
1980	50,274.04	1.01	15.00	0.88622	44,554
1981	100,112.42	1.25	15.00	0.87064	87,162
1982	150,081.96	1.50	15.00	0.85487	128,301
1983	203,368.20	1.77	15.00	0.83798	170,419
1984	159,200.56	2.07	15.00	0.81903	130,390
1985	275,028.67	2.41	15.00	0.79720	219,252
1986	99,374.85	2.82	15.00	0.77168	76,686
1987	55,263.63	3.28	15.00	0.74220	41,017

Montana-Dakota Utilities Company
Common Plant
391.10 OFFICE FURNITURE & EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 5% *Average Service Life:* 15 *Survivor Curve:* R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1988	47,143.87	3.81	15.00	0.70862	33,407
1989	42,984.46	4.40	15.00	0.67120	28,851
1990	204,173.35	5.05	15.00	0.63031	128,693
1991	76,877.12	5.74	15.00	0.58628	45,071
1992	50,233.30	6.48	15.00	0.53952	27,102
1993	109,964.67	7.26	15.00	0.49034	53,920
1994	96,732.58	8.07	15.00	0.43887	42,453
1995	76,776.57	8.92	15.00	0.38533	29,584
1996	108,369.02	9.79	15.00	0.32988	35,749
1997	234,174.95	10.69	15.00	0.27267	63,853
1998	108,233.34	11.62	15.00	0.21395	23,157
1999	194,687.24	12.57	15.00	0.15397	29,976
2000	256,353.83	13.53	15.00	0.09294	23,826
2001	298,246.52	14.51	15.00	0.03113	9,285
Total	3,716,416.91				2,133,201.50

Montana-Dakota Utilities Company

Common Plant

391.20 COMPUTER EQUIPMENT- HONEYWELL

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 7 Survivor Curve: R1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1986	159.20	0.00	0.00	1.00000	159
1987	939.23	0.00	0.00	1.00000	939
1988	642.03	0.50	7.00	0.92861	596
1989	18,685.68	0.63	7.00	0.91047	17,013
1990	18,073.93	0.88	7.00	0.87405	15,797
1991	12,386.05	1.19	7.00	0.83078	10,290
1992	5,761.78	1.53	7.00	0.78139	4,502
1993	1,742.77	1.92	7.00	0.72593	1,265
1994	20,126.70	2.35	7.00	0.66405	13,365
1995	212.98	2.83	7.00	0.59531	127
1996	10,154.40	3.37	7.00	0.51936	5,274
1997	4,499.50	3.95	7.00	0.43624	1,963
1998	8.03	4.58	7.00	0.34672	3
Total	93,392.28				71,293.71

Montana-Dakota Utilities Company

Common Plant

391.50 COMPUTER EQUIPMENT - OTHER

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *5* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1991	268,804.48	0.00	0.00	1.00000	268,804
1992	221,442.66	0.00	0.00	1.00000	221,443
1994	669.20	0.50	5.00	0.90001	602
1995	246,056.34	0.61	5.00	0.87730	215,865
1996	21,913.91	0.86	5.00	0.82737	18,131
1997	11,134.81	1.30	5.00	0.74081	8,249
2000	48,373.78	3.57	5.00	0.28673	13,870
2001	2,004.39	4.51	5.00	0.09781	196
Total	820,399.57				747,159.91

Montana-Dakota Utilities Company

Common Plant

393.00 STORES EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 30 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1993	1,925.33	22.63	30.00	0.24577	473
1995	16,301.46	24.30	30.00	0.19015	3,100
1996	3,495.87	25.15	30.00	0.16177	566
1997	18,728.58	26.01	30.00	0.13307	2,492
1998	175.14	26.88	30.00	0.10404	18
2001	6,759.17	29.55	30.00	0.01509	102
Total	47,385.55				6,750.77

Montana-Dakota Utilities Company

Common Plant

394.10 TOOLS, SHOP & GARAGE EQ. - (NON-UNITIZED)

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *18* *Survivor Curve:* *R2*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	12,561.33	10.16	18.00	0.43578	5,474
1993	4,687.63	10.90	18.00	0.39467	1,850
1994	78,684.31	11.66	18.00	0.35231	27,721
1995	560.01	12.44	18.00	0.30870	173
1996	13,482.62	13.25	18.00	0.26397	3,559
1997	17,077.88	14.07	18.00	0.21812	3,725
1998	45,406.59	14.92	18.00	0.17125	7,776
1999	18,449.52	15.78	18.00	0.12342	2,277
2000	14,608.41	16.66	18.00	0.07467	1,091
2001	29,507.70	17.55	18.00	0.02510	741
Total	235,026.00				54,386.01

Montana-Dakota Utilities Company
Common Plant
394.30 VEHICLE MAINTENANCE EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 20 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1988	369.59	8.02	20.00	0.59910	221
1989	760.65	8.77	20.00	0.56171	427
1991	32,309.61	10.35	20.00	0.48264	15,594
1992	376.22	11.18	20.00	0.44113	166
1993	22,016.33	12.03	20.00	0.39848	8,773
1994	19,130.19	12.91	20.00	0.35466	6,785
1998	15,978.08	16.60	20.00	0.17003	2,717
1999	3,603.02	17.56	20.00	0.12204	440
2000	5,963.88	18.53	20.00	0.07352	438
2001	2,238.57	19.51	20.00	0.02460	55
Total	102,746.14				35,616.20

Montana-Dakota Utilities Company
Common Plant
394.40 VEHICLE REFUELING EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 20 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1986	243,205.76	6.62	20.00	0.66920	162,753
1987	3,402.61	7.30	20.00	0.63504	2,161
1988	2,890.28	8.02	20.00	0.59910	1,732
1991	140,655.25	10.35	20.00	0.48264	67,885
1992	73,962.19	11.18	20.00	0.44113	32,627
1993	165,847.96	12.03	20.00	0.39848	66,088
1994	48,249.96	12.91	20.00	0.35466	17,112
1996	61,784.64	14.72	20.00	0.26405	16,314
1997	18.20	15.65	20.00	0.21741	4
1998	34,000.89	16.60	20.00	0.17003	5,781
2001	64,813.03	19.51	20.00	0.02460	1,594
Total	838,830.77				374,050.43

Montana-Dakota Utilities Company

Common Plant

397.10 COMMUNICATION EQUIP. - FIXED RADIOS

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -10% Average Service Life: 15 Survivor Curve: R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1968	0.08	0.00	0.00	1.10000	0
1969	1.94	0.00	0.00	1.10000	2
1970	39.09	0.00	0.00	1.10000	43
1971	519.05	0.00	0.00	1.10000	571
1972	557.25	0.00	0.00	1.10000	613
1973	170.06	0.00	0.00	1.10000	187
1974	386.38	0.00	0.00	1.10000	425
1975	2,987.20	0.00	0.00	1.10000	3,286
1976	4,975.40	0.00	0.00	1.10000	5,473
1977	2,475.07	0.50	15.00	1.06333	2,632
1978	6,250.64	0.58	15.00	1.05718	6,608
1979	7,343.88	0.78	15.00	1.04316	7,661
1980	23,332.99	1.01	15.00	1.02615	23,943
1981	26,278.13	1.25	15.00	1.00811	26,491
1982	14,586.58	1.50	15.00	0.98985	14,439
1983	32,258.42	1.77	15.00	0.97030	31,300
1984	34,264.05	2.07	15.00	0.94835	32,494
1985	31,553.45	2.41	15.00	0.92307	29,126
1986	83,052.08	2.82	15.00	0.89353	74,209
1987	32,797.40	3.28	15.00	0.85939	28,186
1988	52,271.97	3.81	15.00	0.82051	42,890
1989	23,174.87	4.40	15.00	0.77718	18,011
1990	22,843.44	5.05	15.00	0.72984	16,672
1991	65,839.50	5.74	15.00	0.67884	44,695
1992	23,976.92	6.48	15.00	0.62471	14,979
1993	1,878.61	7.26	15.00	0.56776	1,067
1994	980.52	8.07	15.00	0.50817	498
1995	25,829.71	8.92	15.00	0.44617	11,524

Montana-Dakota Utilities Company

Common Plant

397.10 COMMUNICATION EQUIP. - FIXED RADIOS

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: -10% *Average Service Life:* 15 *Survivor Curve:* R3

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1996	30,098.37	9.79	15.00	0.38197	11,497
1997	9,884.40	10.69	15.00	0.31572	3,121
1998	2,978.64	11.62	15.00	0.24773	738
2000	71,469.03	13.53	15.00	0.10762	7,691
2001	11,131.90	14.51	15.00	0.03605	401
Total	646,187.02				461,472.89

Montana-Dakota Utilities Company

Common Plant

397.20 COMMUNICATION EQUIP. - MOBILE RADIOS

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0 %* *Average Service Life:* *15* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1975	9,731.21	0.00	0.00	1.00000	9,731
1976	39,866.18	0.00	0.00	1.00000	39,866
1977	39,252.58	0.50	15.00	0.96667	37,944
1978	35,627.74	0.58	15.00	0.96107	34,241
1979	38,356.69	0.78	15.00	0.94833	36,375
1980	47,532.29	1.01	15.00	0.93286	44,341
1981	50,016.71	1.25	15.00	0.91647	45,839
1982	34,249.52	1.50	15.00	0.89987	30,820
1983	30,655.73	1.77	15.00	0.88209	27,041
1984	25,214.42	2.07	15.00	0.86214	21,738
1985	47,678.88	2.41	15.00	0.83915	40,010
1986	22,183.24	2.82	15.00	0.81230	18,019
1987	23,044.45	3.28	15.00	0.78127	18,004
1988	53,612.66	3.81	15.00	0.74592	39,991
1989	41,151.18	4.40	15.00	0.70652	29,074
1990	129,469.32	5.05	15.00	0.66349	85,901
1991	52,239.07	5.74	15.00	0.61713	32,238
1992	69,736.92	6.48	15.00	0.56791	39,605
1993	52,917.15	7.26	15.00	0.51615	27,313
1994	77,344.49	8.07	15.00	0.46197	35,731
1995	53,080.07	8.92	15.00	0.40561	21,530
1996	52,745.50	9.79	15.00	0.34724	18,316
1997	10,478.24	10.69	15.00	0.28702	3,007
1998	27,953.14	11.62	15.00	0.22521	6,295
2000	180,485.36	13.53	15.00	0.09783	17,658
2001	40,400.26	14.51	15.00	0.03277	1,324
Total	1,285,023.00				761,952.28

Montana-Dakota Utilities Company
Common Plant
397.30 TELEPHONE COMMUNICATION EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2001
Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 10% Average Service Life: 10 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1984	25,691.19	0.50	10.00	0.85497	21,965
1985	22,226.48	0.66	10.00	0.84055	18,683
1986	7,931.65	0.91	10.00	0.81817	6,489
1987	12,018.09	1.18	10.00	0.79363	9,538
1988	4,652.33	1.47	10.00	0.76773	3,572
1989	1,025.33	1.78	10.00	0.73939	758
1990	46,487.84	2.14	10.00	0.70720	32,876
1991	31,119.91	2.55	10.00	0.67015	20,855
1992	4,685.71	3.03	10.00	0.62775	2,941
1993	30,900.54	3.56	10.00	0.57991	17,920
1994	39,866.57	4.15	10.00	0.52682	21,003
1995	27,829.98	4.79	10.00	0.46885	13,048
1996	128,560.19	5.48	10.00	0.40641	52,249
1997	204,550.06	6.22	10.00	0.33992	69,530
1998	31,208.98	7.00	10.00	0.26975	8,418
1999	10,343.81	7.82	10.00	0.19624	2,030
2000	83,627.04	8.67	10.00	0.11972	10,012
2001	67,095.53	9.55	10.00	0.04052	2,719
Total	779,821.23				314,605.76

Montana-Dakota Utilities Company

Common Plant

397.50 SUPERVISORY & TELEMETERING EQUIP.

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 0% Average Service Life: 15 Survivor Curve: L1

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1966	26.04	2.19	15.00	0.85424	22
1967	5.81	2.37	15.00	0.84215	5
1968	4,040.60	2.55	15.00	0.82972	3,353
1969	103.88	2.75	15.00	0.81690	85
1970	2,858.24	2.94	15.00	0.80394	2,298
1973	985.77	3.56	15.00	0.76296	752
1974	358.45	3.77	15.00	0.74864	268
1998	2,188.46	12.04	15.00	0.19751	432
2001	37,728.70	14.53	15.00	0.03115	1,175
Total	48,295.95				8,390.26

Montana-Dakota Utilities Company

Common Plant

397.80 NETWORK EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *0%* *Average Service Life:* *5* *Survivor Curve:* *R3*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1992	4,119.65	0.00	0.00	1.00000	4,120
1993	929.34	0.00	0.00	1.00000	929
1994	4,786.29	0.50	5.00	0.90001	4,308
1995	72,165.93	0.61	5.00	0.87730	63,311
1996	5,967.06	0.86	5.00	0.82737	4,937
1997	54,268.53	1.30	5.00	0.74081	40,203
1998	219,949.99	1.93	5.00	0.61498	135,265
1999	30,375.12	2.69	5.00	0.46107	14,005
2000	289,947.62	3.57	5.00	0.28673	83,137
2001	142,438.69	4.51	5.00	0.09781	13,932
Total	824,948.22				364,147.24

Montana-Dakota Utilities Company

Common Plant

398.00 MISCELLANEOUS EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: 5% Average Service Life: 20 Survivor Curve: R2

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1965	0.07	0.50	20.00	0.92625	0
1966	0.61	0.55	20.00	0.92367	1
1967	6.90	0.78	20.00	0.91304	6
1968	24.86	1.02	20.00	0.90157	22
1969	412.36	1.29	20.00	0.88855	366
1970	293.15	1.57	20.00	0.87553	257
1971	1,721.07	1.86	20.00	0.86189	1,483
1972	1,266.40	2.14	20.00	0.84841	1,074
1973	812.89	2.43	20.00	0.83451	678
1974	2,388.48	2.73	20.00	0.82054	1,960
1975	4,312.72	3.03	20.00	0.80591	3,476
1976	2,194.65	3.35	20.00	0.79071	1,735
1977	3,015.98	3.69	20.00	0.77451	2,336
1978	3,683.05	4.06	20.00	0.75730	2,789
1979	8,119.41	4.45	20.00	0.73885	5,999
1980	7,260.95	4.86	20.00	0.71909	5,221
1981	6,648.93	5.31	20.00	0.69795	4,641
1982	13,915.55	5.78	20.00	0.67541	9,399
1983	4,971.62	6.28	20.00	0.65147	3,239
1984	4,809.36	6.82	20.00	0.62606	3,011
1985	7,165.93	7.38	20.00	0.59932	4,295
1986	14,352.71	7.98	20.00	0.57117	8,198
1987	41,087.40	8.59	20.00	0.54178	22,260
1988	5,680.41	9.24	20.00	0.51107	2,903
1989	27,362.82	9.91	20.00	0.47923	13,113
1990	43,519.58	10.61	20.00	0.44618	19,418
1991	11,719.06	11.32	20.00	0.41211	4,830
1992	6,337.32	12.06	20.00	0.37693	2,389

Montana-Dakota Utilities Company

Common Plant

398.00 MISCELLANEOUS EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2001

Based Upon Broad Group/Remaining Life Procedure and Technique

Salvage Value: *5%* *Average Service Life:* *20* *Survivor Curve:* *R2*

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1993	35,426.75	12.82	20.00	0.34083	12,075
1994	48,383.48	13.61	20.00	0.30373	14,696
1995	34,402.42	14.40	20.00	0.26578	9,144
1996	24,449.82	15.22	20.00	0.22696	5,549
1997	31,707.42	16.06	20.00	0.18732	5,939
1998	8,056.46	16.91	20.00	0.14689	1,183
1999	19,833.33	17.77	20.00	0.10577	2,098
2000	41,398.58	18.65	20.00	0.06392	2,646
2001	126,152.43	19.55	20.00	0.02147	2,709
Total	592,894.93				181,137.55

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 390 - Structures & Improvements

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	4,755.66	662.00	13.92%	40.08	0.84%	621.92	13.08%
1969	23,146.27	350.00	1.51%	978.69	4.23%	(628.69)	-2.72%
1970	9,535.95	5,550.94	58.21%	1,401.83	14.70%	4,149.11	43.51%
1971	55.50	816.00	1470.27%	1,457.69	2626.47%	(641.69)	-1156.20%
1972	89,020.14	20,850.79	23.42%	100.23	0.11%	20,750.56	23.31%
1973	823.15	556.00	67.55%	0.00	0.00%	556.00	67.55%
1974	6,649.36	0.00	0.00%	2,380.69	35.80%	(2,380.69)	-35.80%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	698.69	0.00	0.00%	17.84	2.55%	(17.84)	-2.55%
1977	33,563.08	10.00	0.03%	7,368.10	21.95%	(7,358.10)	-21.92%
1978	5,945.18	166.75	2.80%	470.81	7.92%	(304.06)	-5.11%
1979	361.83	(2.15)	-0.59%	28.73	7.94%	(30.88)	-8.53%
1980	36,428.79	46,043.00	126.39%	0.00	0.00%	46,043.00	126.39%
1981	386.16	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	2,390.36	(35,198.49)	-1472.52%	0.00	0.00%	(35,198.49)	-1472.52%
1983	151,268.18	52,055.19	34.41%	17,106.40	11.31%	34,948.79	23.10%
1984	0.00	239.87	0.00%	0.00	0.00%	239.87	0.00%
1985	29,321.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	353,205.79	462.87	0.13%	23,017.27	6.52%	(22,554.40)	-6.39%
1987	114,668.89	6.60	0.01%	178,550.90	155.71%	(178,544.30)	-155.70%
1988	1,065.81	20.00	1.88%	44,427.72	4168.45%	(44,407.72)	-4166.57%
1989	2,907.81	0.00	0.00%	1,361.75	46.83%	(1,361.75)	-46.83%
1990	1,179.28	0.00	0.00%	4,183.53	354.75%	(4,183.53)	-354.75%
1991	11,317.67	0.00	0.00%	21,000.00	185.55%	(21,000.00)	-185.55%
1992	6,400.00	0.00	0.00%	59,485.65	929.46%	(59,485.65)	-929.46%
1993	66,938.07	5,500.00	8.22%	11,015.00	16.46%	(5,515.00)	-8.24%
1994	76,339.95	52.50	0.07%	3,348.28	4.39%	(3,295.78)	-4.32%
1995	249,269.07	188,096.00	75.46%	48,516.38	19.46%	139,579.62	56.00%
1996	174,572.37	26,753.21	15.32%	22,545.80	12.91%	4,207.41	2.41%
1997	97,788.56	45,363.50	46.39%	4,264.75	4.36%	41,098.75	42.03%
1998	255,811.74	0.00	0.00%	40,398.90	15.79%	(40,398.90)	-15.79%
1999	303,792.23	30,685.00	10.10%	12,226.33	4.02%	18,458.67	6.08%
2000	172,070.45	10,283.75	5.98%	30,934.95	17.98%	(20,651.20)	-12.00%
2001	109,759.98	0.00	0.00%	14,718.75	13.41%	(14,718.75)	-13.41%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 390 - Structures & Improvements

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	37,437.88	6,562.94	17.53%	2,420.60	6.47%	4,142.34	11.06%
1969-1971	32,737.72	6,716.94	20.52%	3,838.21	11.72%	2,878.73	8.79%
1970-1972	98,611.59	27,217.73	27.60%	2,959.75	3.00%	24,257.98	24.60%
1971-1973	89,898.79	22,222.79	24.72%	1,557.92	1.73%	20,664.87	22.99%
1972-1974	96,492.65	21,406.79	22.18%	2,480.92	2.57%	18,925.87	19.61%
1973-1975	7,472.51	556.00	7.44%	2,380.69	31.86%	(1,824.69)	-24.42%
1974-1976	7,348.05	0.00	0.00%	2,398.53	32.64%	(2,398.53)	-32.64%
1975-1977	34,261.77	10.00	0.03%	7,385.94	21.56%	(7,375.94)	-21.53%
1976-1978	40,206.95	176.75	0.44%	7,856.75	19.54%	(7,680.00)	-19.10%
1977-1979	39,870.09	174.60	0.44%	7,867.64	19.73%	(7,693.04)	-19.30%
1978-1980	42,735.80	46,207.60	108.12%	499.54	1.17%	45,708.06	106.95%
1979-1981	37,176.78	46,040.85	123.84%	28.73	0.08%	46,012.12	123.77%
1980-1982	39,205.31	10,844.51	27.66%	0.00	0.00%	10,844.51	27.66%
1981-1983	154,044.70	16,856.70	10.94%	17,106.40	11.10%	(249.70)	-0.16%
1982-1984	153,658.54	17,096.57	11.13%	17,106.40	11.13%	(9.83)	-0.01%
1983-1985	180,589.18	52,295.06	28.96%	17,106.40	9.47%	35,188.66	19.49%
1984-1986	382,526.79	702.74	0.18%	23,017.27	6.02%	(22,314.53)	-5.83%
1985-1987	497,195.68	469.47	0.09%	201,568.17	40.54%	(201,098.70)	-40.45%
1986-1988	468,940.49	489.47	0.10%	245,995.89	52.46%	(245,506.42)	-52.35%
1987-1989	118,642.51	26.60	0.02%	224,340.37	189.09%	(224,313.77)	-189.07%
1988-1990	5,152.90	20.00	0.39%	49,973.00	969.80%	(49,953.00)	-969.42%
1989-1991	15,404.76	0.00	0.00%	26,545.28	172.32%	(26,545.28)	-172.32%
1990-1992	18,896.95	0.00	0.00%	84,669.18	448.06%	(84,669.18)	-448.06%
1991-1993	84,655.74	5,500.00	6.50%	91,500.65	108.09%	(86,000.65)	-101.59%
1992-1994	149,678.02	5,552.50	3.71%	73,848.93	49.34%	(68,296.43)	-45.63%
1993-1995	392,547.09	193,648.50	49.33%	62,879.66	16.02%	130,768.84	33.31%
1994-1996	500,181.39	214,901.71	42.96%	74,410.46	14.88%	140,491.25	28.09%
1995-1997	521,630.00	260,212.71	49.88%	75,326.93	14.44%	184,885.78	35.44%
1996-1998	528,172.67	72,116.71	13.65%	67,209.45	12.72%	4,907.26	0.93%
1997-1999	657,392.53	76,048.50	11.57%	56,889.98	8.65%	19,158.52	2.91%
1998-2000	731,674.42	40,968.75	5.60%	83,560.18	11.42%	(42,591.43)	-5.82%
1999-2001	585,622.66	40,968.75	7.00%	57,880.03	9.88%	(16,911.28)	-2.89%
1968-2001	2,391,436.97	399,323.33	16.70%	551,347.05	23.06%	(152,023.72)	-6.36%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	18.52%
1987-2001	15-Year Trend	26.16%
1992-2001	10-Year Trend	18.88%
1997-2001	5-Year Trend	-10.61%

Adjusted Salvage & C/O/R			**-10.61%**	**37.37%**	**-47.98%**
2001 Total	3,412,449.42	3,028,920.86			
LESS:					
Schuchart Bldg.	3,302,689.44	3,028,920.86			
Net Activity	109,759.98	0.00			

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 391 - Office Furniture & Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	149,545.34	7,315.45	4.89%	0.00	0.00%	7,315.45	4.89%
1969	12,514.88	706.47	5.65%	0.00	0.00%	706.47	5.65%
1970	7,668.23	624.11	8.14%	0.00	0.00%	624.11	8.14%
1971	21,052.46	1,364.00	6.48%	0.00	0.00%	1,364.00	6.48%
1972	32,454.24	4,881.40	15.04%	0.00	0.00%	4,881.40	15.04%
1973	15,218.01	2,008.66	13.20%	0.00	0.00%	2,008.66	13.20%
1974	35,762.81	4,645.38	12.99%	0.00	0.00%	4,645.38	12.99%
1975	15,098.57	1,163.76	7.71%	0.00	0.00%	1,163.76	7.71%
1976	21,310.59	1,353.89	6.35%	0.00	0.00%	1,353.89	6.35%
1977	36,855.70	928.43	2.52%	0.00	0.00%	928.43	2.52%
1978	22,486.72	2,884.80	12.83%	0.00	0.00%	2,884.80	12.83%
1979	9,907.61	1,249.28	12.61%	22.87	0.23%	1,226.41	12.38%
1980	12,336.10	876.42	7.10%	0.00	0.00%	876.42	7.10%
1981	13,528.25	3,101.10	22.92%	55.72	0.41%	3,045.38	22.51%
1982	47,102.04	6,499.43	13.80%	(16.00)	-0.03%	6,515.43	13.83%
1983	27,101.38	5,516.00	20.35%	(5.00)	-0.02%	5,521.00	20.37%
1984	46,038.43	4,456.51	9.68%	(40.00)	-0.09%	4,496.51	9.77%
1985	111,030.81	46,813.68	42.16%	0.00	0.00%	46,813.68	42.16%
1986	75,056.59	10,944.66	14.58%	0.00	0.00%	10,944.66	14.58%
1987	46,112.97	11,033.78	23.93%	0.00	0.00%	11,033.78	23.93%
1988	16,519.26	3,484.13	21.09%	0.00	0.00%	3,484.13	21.09%
1989	31,587.31	11,645.08	36.87%	0.00	0.00%	11,645.08	36.87%
1990	32,505.28	408.18	1.26%	0.00	0.00%	408.18	1.26%
1991	49,846.33	869.49	1.74%	0.00	0.00%	869.49	1.74%
1992	182,419.62	811.85	0.45%	0.00	0.00%	811.85	0.45%
1993	62,549.07	64.00	0.10%	72.54	0.12%	(8.54)	-0.01%
1994	76,446.67	300.77	0.39%	(0.24)	0.00%	301.01	0.39%
1995	69,409.77	725.00	1.04%	0.00	0.00%	725.00	1.04%
1996	59,531.16	2,105.34	3.54%	0.00	0.00%	2,105.34	3.54%
1997	169,631.02	7,079.29	4.17%	0.00	0.00%	7,079.29	4.17%
1998	35,456.30	1,244.25	3.51%	0.00	0.00%	1,244.25	3.51%
1999	58,845.23	2,072.98	3.52%	0.00	0.00%	2,072.98	3.52%
2000	80,687.94	2,165.51	2.68%	1,158.00	1.44%	1,007.51	1.25%
2001	93,113.08	3,197.53	3.43%	0.00	0.00%	3,197.53	3.43%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 391 - Office Furniture & Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	169,728.45	8,646.03	5.09%	0.00	0.00%	8,646.03	5.09%
1969-1971	41,235.57	2,694.58	6.53%	0.00	0.00%	2,694.58	6.53%
1970-1972	61,174.93	6,869.51	11.23%	0.00	0.00%	6,869.51	11.23%
1971-1973	68,724.71	8,254.06	12.01%	0.00	0.00%	8,254.06	12.01%
1972-1974	83,435.06	11,535.44	13.83%	0.00	0.00%	11,535.44	13.83%
1973-1975	66,079.39	7,817.80	11.83%	0.00	0.00%	7,817.80	11.83%
1974-1976	72,171.97	7,163.03	9.92%	0.00	0.00%	7,163.03	9.92%
1975-1977	73,264.86	3,446.08	4.70%	0.00	0.00%	3,446.08	4.70%
1976-1978	80,653.01	5,167.12	6.41%	0.00	0.00%	5,167.12	6.41%
1977-1979	69,250.03	5,062.51	7.31%	22.87	0.03%	5,039.64	7.28%
1978-1980	44,730.43	5,010.50	11.20%	22.87	0.05%	4,987.63	11.15%
1979-1981	35,771.96	5,226.80	14.61%	78.59	0.22%	5,148.21	14.39%
1980-1982	72,966.39	10,476.95	14.36%	39.72	0.05%	10,437.23	14.30%
1981-1983	87,731.67	15,116.53	17.23%	34.72	0.04%	15,081.81	17.19%
1982-1984	120,241.85	16,471.94	13.70%	(61.00)	-0.05%	16,532.94	13.75%
1983-1985	184,170.62	56,786.19	30.83%	(45.00)	-0.02%	56,831.19	30.86%
1984-1986	232,125.83	62,214.85	26.80%	(40.00)	-0.02%	62,254.85	26.82%
1985-1987	232,200.37	68,792.12	29.63%	0.00	0.00%	68,792.12	29.63%
1986-1988	137,688.82	25,462.57	18.49%	0.00	0.00%	25,462.57	18.49%
1987-1989	94,219.54	26,162.99	27.77%	0.00	0.00%	26,162.99	27.77%
1988-1990	80,611.85	15,537.39	19.27%	0.00	0.00%	15,537.39	19.27%
1989-1991	113,938.92	12,922.75	11.34%	0.00	0.00%	12,922.75	11.34%
1990-1992	264,771.23	2,089.52	0.79%	0.00	0.00%	2,089.52	0.79%
1991-1993	294,815.02	1,745.34	0.59%	72.54	0.02%	1,672.80	0.57%
1992-1994	321,415.36	1,176.62	0.37%	72.30	0.02%	1,104.32	0.34%
1993-1995	208,405.51	1,089.77	0.52%	72.30	0.03%	1,017.47	0.49%
1994-1996	205,387.60	3,131.11	1.52%	(0.24)	0.00%	3,131.35	1.52%
1995-1997	298,571.95	9,909.63	3.32%	0.00	0.00%	9,909.63	3.32%
1996-1998	264,618.48	10,428.88	3.94%	0.00	0.00%	10,428.88	3.94%
1997-1999	263,932.55	10,396.52	3.94%	0.00	0.00%	10,396.52	3.94%
1998-2000	174,989.47	5,482.74	3.13%	1,158.00	0.66%	4,324.74	2.47%
1999-2001	232,646.25	7,436.02	3.20%	1,158.00	0.50%	6,278.02	2.70%
1968-2001	1,776,729.77	154,540.61	8.70%	1,247.89	0.07%	153,292.72	8.63%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	-2.58%
1987-2001	15-Year Trend	-5.20%
1992-2001	10-Year Trend	4.44%
1997-2001	5-Year Trend	3.19%

Adjusted Salvage & C/O/R			**3.19%**	**0.11%**	**3.08%**
2001 Total	875,231.85	733,970.93			
LESS:					
Schuchart Bld	782,118.77	730,773.40			
Net Activity	93,113.08	3,197.53			

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Accounts 391.2 - Computer Equipment (Honeywell) & 391.4 - (Sun/Prime)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	226,617.84	27,500.00	12.13%	1,575.70	0.70%	25,924.30	11.44%
1985	62,203.01	24,002.82	38.59%	0.00	0.00%	24,002.82	38.59%
1986	325,064.40	97,873.56	30.11%	0.00	0.00%	97,873.56	30.11%
1987	75,004.06	2,391.68	3.19%	0.00	0.00%	2,391.68	3.19%
1988	39,079.68	3,734.00	9.55%	0.00	0.00%	3,734.00	9.55%
1989	2,433,506.07	146,310.40	6.01%	0.00	0.00%	146,310.40	6.01%
1990	511,968.95	78,419.00	15.32%	0.00	0.00%	78,419.00	15.32%
1991	7,906.80	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	667,002.95	21,747.59	3.26%	0.00	0.00%	21,747.59	3.26%
1993	107,753.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	163,832.19	4,000.00	2.44%	0.00	0.00%	4,000.00	2.44%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	80,769.58	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	1,162.34	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	50,529.61	5,000.00	9.90%	0.00	0.00%	5,000.00	9.90%
1999	26,666.03	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	3,439,246.76	1,250.00	0.04%	698.54	0.02%	551.46	0.02%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Accounts 391.2 - Computer Equipment (Honeywell) & 391.4 - (Sun/Prime)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	226,617.84	27,500.00	12.13%	1,575.70	0.70%	25,924.30	11.44%
1983-1985	288,820.85	51,502.82	17.83%	1,575.70	0.55%	49,927.12	17.29%
1984-1986	613,885.25	149,376.38	24.33%	1,575.70	0.26%	147,800.68	24.08%
1985-1987	462,271.47	124,268.06	26.88%	0.00	0.00%	124,268.06	26.88%
1986-1988	439,148.14	103,999.24	23.68%	0.00	0.00%	103,999.24	23.68%
1987-1989	2,547,589.81	152,436.08	5.98%	0.00	0.00%	152,436.08	5.98%
1988-1990	2,984,554.70	228,463.40	7.65%	0.00	0.00%	228,463.40	7.65%
1989-1991	2,953,381.82	224,729.40	7.61%	0.00	0.00%	224,729.40	7.61%
1990-1992	1,186,878.70	100,166.59	8.44%	0.00	0.00%	100,166.59	8.44%
1991-1993	782,663.65	21,747.59	2.78%	0.00	0.00%	21,747.59	2.78%
1992-1994	938,589.04	25,747.59	2.74%	0.00	0.00%	25,747.59	2.74%
1993-1995	271,586.09	4,000.00	1.47%	0.00	0.00%	4,000.00	1.47%
1994-1996	244,601.77	4,000.00	1.64%	0.00	0.00%	4,000.00	1.64%
1995-1997	81,931.92	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	132,461.53	5,000.00	3.77%	0.00	0.00%	5,000.00	3.77%
1997-1999	78,357.98	5,000.00	6.38%	0.00	0.00%	5,000.00	6.38%
1998-2000	3,516,442.40	6,250.00	0.18%	698.54	0.02%	5,551.46	0.16%
1999-2001	3,465,912.79	1,250.00	0.04%	698.54	0.02%	551.46	0.02%
1968-2001	8,218,314.17	412,229.05	5.02%	2,274.24	0.03%	409,954.81	4.99%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.21%
1987-2001	15-Year Trend	-4.25%
1992-2001	10-Year Trend	0.40%
1997-2001	5-Year Trend	1.02%

Adjusted Salvage & C/O/R			**1.02%**	**0.04%**	**0.97%**
2001 Total	875,231.85	733,970.93			
LESS:					
Schuchart Bldg	782,118.77	730,773.40			
Net Activity	93,113.08	3,197.53			

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 391.3 - Computer Equipment - PC

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	16,323.58	218.76	1.34%	0.00	0.00%	218.76	1.34%
1993	24,638.45	1,093.74	4.44%	0.00	0.00%	1,093.74	4.44%
1994	71,970.57	3,693.70	5.13%	0.00	0.00%	3,693.70	5.13%
1995	101,939.34	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	24,221.86	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	26,853.75	2,585.00	9.63%	0.00	0.00%	2,585.00	9.63%
1998	390,103.65	5,604.45	1.44%	0.00	0.00%	5,604.45	1.44%
1999	435,616.00	2,250.00	0.52%	0.00	0.00%	2,250.00	0.52%
2000	154,278.59	250.00	0.16%	0.00	0.00%	250.00	0.16%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 391.3 - Computer Equipment - PC

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	16,323.58	218.76	1.34%	0.00	0.00%	218.76	1.34%
1991-1993	40,962.03	1,312.50	3.20%	0.00	0.00%	1,312.50	3.20%
1992-1994	112,932.60	5,006.20	4.43%	0.00	0.00%	5,006.20	4.43%
1993-1995	198,548.36	4,787.44	2.41%	0.00	0.00%	4,787.44	2.41%
1994-1996	198,131.77	3,693.70	1.86%	0.00	0.00%	3,693.70	1.86%
1995-1997	153,014.95	2,585.00	1.69%	0.00	0.00%	2,585.00	1.69%
1996-1998	441,179.26	8,189.45	1.86%	0.00	0.00%	8,189.45	1.86%
1997-1999	852,573.40	10,439.45	1.22%	0.00	0.00%	10,439.45	1.22%
1998-2000	979,998.24	8,104.45	0.83%	0.00	0.00%	8,104.45	0.83%
1999-2001	589,894.59	2,500.00	0.42%	0.00	0.00%	2,500.00	0.42%
1968-2001	1,245,945.79	15,695.65	1.26%	0.00	0.00%	15,695.65	1.26%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	2.15%
1987-2001	15-Year Trend	2.05%
1992-2001	10-Year Trend	0.50%
1997-2001	5-Year Trend	0.14%

Adjusted Salvage & C/O/R		**0.14%**	**0.00%**	**0.14%**

2001 Total	1,281,750.88	366,681.15
LESS:		
Schuchart Bldg Eq	1,281,750.88	366,681.15
Net Activity	0.00	0.00

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 391.5 - Computer Equipment (Other)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	3,371.10	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	3,661.59	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 391.5 - Computer Equipment (Other)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	3,371.10	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	3,371.10	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	7,032.69	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	3,661.59	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	3,661.59	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	7,032.69	0.00	0.00%	0.00	0.00%	0.00	0.00%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.00%
1987-2001	15-Year Trend	0.00%
1992-2001	10-Year Trend	0.00%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R			**0.00%**	**0.00%**	**0.00%**
2001 Total	3,346.85	3,149.84			
LESS:					
Schuchart Bldg Eq	3,346.85	3,149.84			
Net Activity	0.00	0.00			

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 392.1 - Transportation Equipment (Trailers)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	246.00	71,707.06	29149.21%	149.91	60.94%	71,557.15	29088.27%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	2,704.53	1,212.98	44.85%	0.00	0.00%	1,212.98	44.85%
1977	1,185.10	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	412.19	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	3,422.98	732.00	21.38%	0.00	0.00%	732.00	21.38%
1984	7,618.25	2,000.00	26.25%	0.00	0.00%	2,000.00	26.25%
1985	118,612.65	4,547.20	3.83%	0.00	0.00%	4,547.20	3.83%
1986	661.19	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	30.12	0.00%	0.00	0.00%	30.12	0.00%
1989	1,569.70	400.00	25.48%	0.00	0.00%	400.00	25.48%
1990	1,141.64	0.00	0.00%	5.92	0.52%	(5.92)	-0.52%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	3,394.18	1,817.50	53.55%	0.00	0.00%	1,817.50	53.55%
1993	10.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	2,004.82	345.00	17.21%	0.00	0.00%	345.00	17.21%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	15,692.74	9,858.08	62.82%	356.00	2.27%	9,502.08	60.55%
1997	1,174.62	54.30	4.62%	0.00	0.00%	54.30	4.62%
1998	1,161.61	39.95	3.44%	0.00	0.00%	39.95	3.44%
1999	8,701.98	1,450.00	16.66%	0.00	0.00%	1,450.00	16.66%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	181.56	275.00	151.47%	0.00	0.00%	275.00	151.47%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 392.1 - Transportation Equipment (Trailers)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	246.00	71,707.06	29149.21%	149.91	60.94%	71,557.15	29088.27%
1970-1972	246.00	71,707.06	29149.21%	149.91	60.94%	71,557.15	29088.27%
1971-1973	246.00	71,707.06	29149.21%	149.91	60.94%	71,557.15	29088.27%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	2,704.53	1,212.98	44.85%	0.00	0.00%	1,212.98	44.85%
1975-1977	3,889.63	1,212.98	31.18%	0.00	0.00%	1,212.98	31.18%
1976-1978	4,301.82	1,212.98	28.20%	0.00	0.00%	1,212.98	28.20%
1977-1979	1,597.29	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	412.19	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	3,422.98	732.00	21.38%	0.00	0.00%	732.00	21.38%
1982-1984	11,041.23	2,732.00	24.74%	0.00	0.00%	2,732.00	24.74%
1983-1985	129,653.88	7,279.20	5.61%	0.00	0.00%	7,279.20	5.61%
1984-1986	126,892.09	6,547.20	5.16%	0.00	0.00%	6,547.20	5.16%
1985-1987	119,273.84	4,547.20	3.81%	0.00	0.00%	4,547.20	3.81%
1986-1988	661.19	30.12	4.56%	0.00	0.00%	30.12	4.56%
1987-1989	1,569.70	430.12	27.40%	0.00	0.00%	430.12	27.40%
1988-1990	2,711.34	430.12	15.86%	5.92	0.22%	424.20	15.65%
1989-1991	2,711.34	400.00	14.75%	5.92	0.22%	394.08	14.53%
1990-1992	4,535.82	1,817.50	40.07%	5.92	0.13%	1,811.58	39.94%
1991-1993	3,404.18	1,817.50	53.39%	0.00	0.00%	1,817.50	53.39%
1992-1994	5,409.00	2,162.50	39.98%	0.00	0.00%	2,162.50	39.98%
1993-1995	2,014.82	345.00	17.12%	0.00	0.00%	345.00	17.12%
1994-1996	17,697.56	10,203.08	57.65%	356.00	2.01%	9,847.08	55.64%
1995-1997	16,867.36	9,912.38	58.77%	356.00	2.11%	9,556.38	56.66%
1996-1998	18,028.97	9,952.33	55.20%	356.00	1.97%	9,596.33	53.23%
1997-1999	11,038.21	1,544.25	13.99%	0.00	0.00%	1,544.25	13.99%
1998-2000	9,863.59	1,489.95	15.11%	0.00	0.00%	1,489.95	15.11%
1999-2001	8,883.54	1,725.00	19.42%	0.00	0.00%	1,725.00	19.42%
1968-2001	169,895.74	94,469.19	55.60%	511.83	0.30%	93,957.36	55.30%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	41.35%
1987-2001	15-Year Trend	40.39%
1992-2001	10-Year Trend	21.45%
1997-2001	5-Year Trend	-3.14%

Adjusted Salvage & C/O/R	**-3.14%**	**0.49%**	**-3.63%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 392.2 - Transportation Equipment (Cars & Trucks)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	164,451.98	32,704.22	19.89%	25.78	0.02%	32,678.44	19.87%
1969	271,841.22	60,346.77	22.20%	143.11	0.05%	60,203.66	22.15%
1970	259,931.35	66,130.69	25.44%	236.99	0.09%	65,893.70	25.35%
1971	271,416.28	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	264,790.15	63,974.31	24.16%	164.57	0.06%	63,809.74	24.10%
1973	308,598.98	72,199.39	23.40%	293.41	0.10%	71,905.98	23.30%
1974	241,605.95	77,536.50	32.09%	27.05	0.01%	77,509.45	32.08%
1975	130,372.99	45,884.59	35.19%	0.00	0.00%	45,884.59	35.19%
1976	281,236.74	96,623.97	34.36%	(251.54)	-0.09%	96,875.51	34.45%
1977	382,864.17	134,230.29	35.06%	156.23	0.04%	134,074.06	35.02%
1978	320,558.46	113,702.73	35.47%	0.00	0.00%	113,702.73	35.47%
1979	352,093.67	132,818.59	37.72%	100.47	0.03%	132,718.12	37.69%
1980	366,920.67	129,850.00	35.39%	0.00	0.00%	129,850.00	35.39%
1981	401,828.38	126,607.71	31.51%	1,158.67	0.29%	125,449.04	31.22%
1982	413,793.54	132,072.06	31.92%	1,613.11	0.39%	130,458.95	31.53%
1983	547,143.10	146,554.84	26.79%	539.73	0.10%	146,015.11	26.69%
1984	442,158.28	72,941.51	16.50%	370.55	0.08%	72,570.96	16.41%
1985	2,255,621.28	781,800.12	34.66%	912.53	0.04%	780,887.59	34.62%
1986	539,562.46	64,181.75	11.90%	588.94	0.11%	63,592.81	11.79%
1987	406,940.32	67,112.86	16.49%	2,422.53	0.60%	64,690.33	15.90%
1988	506,735.34	83,356.19	16.45%	5,663.79	1.12%	77,692.40	15.33%
1989	563,190.62	93,145.36	16.54%	2,529.33	0.45%	90,616.03	16.09%
1990	415,225.52	(93,656.92)	-22.56%	2,350.94	0.57%	(96,007.86)	-23.12%
1991	502,235.39	79,339.80	15.80%	1,463.28	0.29%	77,876.52	15.51%
1992	134,810.89	14,484.99	10.74%	859.07	0.64%	13,625.92	10.11%
1993	137,487.82	20,294.21	14.76%	317.04	0.23%	19,977.17	14.53%
1994	317,142.07	65,427.26	20.63%	934.85	0.29%	64,492.41	20.34%
1995	148,592.83	10,008.39	6.74%	48.15	0.03%	9,960.24	6.70%
1996	310,798.23	118,826.49	38.23%	43.49	0.01%	118,783.00	38.22%
1997	140,592.98	31,757.00	22.59%	10,417.57	7.41%	21,339.43	15.18%
1998	240,376.81	47,056.25	19.58%	900.00	0.37%	46,156.25	19.20%
1999	272,550.94	54,971.23	20.17%	206.49	0.08%	54,764.74	20.09%
2000	388,959.44	84,465.00	21.72%	0.00	0.00%	84,465.00	21.72%
2001	505,831.14	135,236.30	26.74%	0.00	0.00%	135,236.30	26.74%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 392.2 - Transportation Equipment (Cars & Trucks)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	696,224.55	159,181.68	22.86%	405.88	0.06%	158,775.80	22.81%
1969-1971	803,188.85	126,477.46	15.75%	380.10	0.05%	126,097.36	15.70%
1970-1972	796,137.78	130,105.00	16.34%	401.56	0.05%	129,703.44	16.29%
1971-1973	844,805.41	136,173.70	16.12%	457.98	0.05%	135,715.72	16.06%
1972-1974	814,995.08	213,710.20	26.22%	485.03	0.06%	213,225.17	26.16%
1973-1975	680,577.92	195,620.48	28.74%	320.46	0.05%	195,300.02	28.70%
1974-1976	653,215.68	220,045.06	33.69%	(224.49)	-0.03%	220,269.55	33.72%
1975-1977	794,473.90	276,738.85	34.83%	(95.31)	-0.01%	276,834.16	34.84%
1976-1978	984,659.37	344,556.99	34.99%	(95.31)	-0.01%	344,652.30	35.00%
1977-1979	1,055,516.30	380,751.61	36.07%	256.70	0.02%	380,494.91	36.05%
1978-1980	1,039,572.80	376,371.32	36.20%	100.47	0.01%	376,270.85	36.19%
1979-1981	1,120,842.72	389,276.30	34.73%	1,259.14	0.11%	388,017.16	34.62%
1980-1982	1,182,542.59	388,529.77	32.86%	2,771.78	0.23%	385,757.99	32.62%
1981-1983	1,362,765.02	405,234.61	29.74%	3,311.51	0.24%	401,923.10	29.49%
1982-1984	1,403,094.92	351,568.41	25.06%	2,523.39	0.18%	349,045.02	24.88%
1983-1985	3,244,922.66	1,001,296.47	30.86%	1,822.81	0.06%	999,473.66	30.80%
1984-1986	3,237,342.02	918,923.38	28.39%	1,872.02	0.06%	917,051.36	28.33%
1985-1987	3,202,124.06	913,094.73	28.52%	3,924.00	0.12%	909,170.73	28.39%
1986-1988	1,453,238.12	214,650.80	14.77%	8,675.26	0.60%	205,975.54	14.17%
1987-1989	1,476,866.28	243,614.41	16.50%	10,615.65	0.72%	232,998.76	15.78%
1988-1990	1,485,151.48	82,844.63	5.58%	10,544.06	0.71%	72,300.57	4.87%
1989-1991	1,480,651.53	78,828.24	5.32%	6,343.55	0.43%	72,484.69	4.90%
1990-1992	1,052,271.80	167.87	0.02%	4,673.29	0.44%	(4,505.42)	-0.43%
1991-1993	774,534.10	114,119.00	14.73%	2,639.39	0.34%	111,479.61	14.39%
1992-1994	589,440.78	100,206.46	17.00%	2,110.96	0.36%	98,095.50	16.64%
1993-1995	603,222.72	95,729.86	15.87%	1,300.04	0.22%	94,429.82	15.65%
1994-1996	776,533.13	194,262.14	25.02%	1,026.49	0.13%	193,235.65	24.88%
1995-1997	599,984.04	160,591.88	26.77%	10,509.21	1.75%	150,082.67	25.01%
1996-1998	691,768.02	197,639.74	28.57%	11,361.06	1.64%	186,278.68	26.93%
1997-1999	653,520.73	133,784.48	20.47%	11,524.06	1.76%	122,260.42	18.71%
1998-2000	901,887.19	186,492.48	20.68%	1,106.49	0.12%	185,385.99	20.56%
1999-2001	1,167,341.52	274,672.53	23.53%	206.49	0.02%	274,466.04	23.51%
1968-2001	13,208,259.99	3,161,984.45	23.94%	34,236.13	0.26%	3,127,748.32	23.68%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	16.99%
1987-2001	15-Year Trend	24.07%
1992-2001	10-Year Trend	29.61%
1997-2001	5-Year Trend	19.69%

Adjusted Salvage & C/O/R	**19.69%**	**0.42%**	**19.27%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 392.4 - Electric Transportation Equipment (Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	134,242.62	18,208.64	13.56%	551.82	0.41%	17,656.82	13.15%
1993	211,453.87	39,656.66	18.75%	880.10	0.42%	38,776.56	18.34%
1994	207,542.69	37,016.70	17.84%	426.92	0.21%	36,589.78	17.63%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	4,971.62	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 392.4 - Electric Transportation Equipment (Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	134,242.62	18,208.64	13.56%	551.82	0.41%	17,656.82	13.15%
1991-1993	345,696.49	57,865.30	16.74%	1431.92	0.41%	56,433.38	16.32%
1992-1994	553,239.18	94,882.00	17.15%	1858.84	0.34%	93,023.16	16.81%
1993-1995	418,996.56	76,673.36	18.30%	1307.02	0.31%	75,366.34	17.99%
1994-1996	212,514.31	37,016.70	17.42%	426.92	0.20%	36,589.78	17.22%
1995-1997	4,971.62	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	4,971.62	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	558,210.80	94,882.00	17.00%	1,858.84	0.33%	93,023.16	16.66%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	7.59%
1987-2001	15-Year Trend	5.81%
1992-2001	10-Year Trend	-4.93%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**0.54%**	**-0.54%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 392.5 - Gas Transportation Equipment (Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	227,373.17	28,291.39	12.44%	869.75	0.38%	27,421.64	12.06%
1993	178,733.29	25,034.34	14.01%	678.51	0.38%	24,355.83	13.63%
1994	516,488.58	119,899.98	23.21%	1236.63	0.24%	118,663.35	22.98%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 392.5 - Gas Transportation Equipment (Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	227,373.17	28,291.39	12.44%	869.75	0.38%	27,421.64	12.06%
1991-1993	406,106.46	53,325.73	13.13%	1548.26	0.38%	51,777.47	12.75%
1992-1994	922,595.04	173,225.71	18.78%	2784.89	0.30%	170,440.82	18.47%
1993-1995	695,221.87	144,934.32	20.85%	1915.14	0.28%	143,019.18	20.57%
1994-1996	516,488.58	119,899.98	23.21%	1236.63	0.24%	118,663.35	22.98%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	922,595.04	173,225.71	18.78%	2,784.89	0.30%	170,440.82	18.47%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	8.37%
1987-2001	15-Year Trend	6.73%
1992-2001	10-Year Trend	-3.94%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**0.49%**	**-0.49%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 394.1 - Tools, Shop & Garage Equipment (Non-Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	729.60	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	976.78	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	810.41	20.00	2.47%	0.00	0.00%	20.00	2.47%
1998	384.06	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	174.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 394.1 - Tools, Shop & Garage Equipment (Non-Unitized)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	729.60	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	1,706.38	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	1,706.38	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	976.78	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	810.41	20.00	2.47%	0.00	0.00%	20.00	2.47%
1996-1998	1,194.47	20.00	1.67%	0.00	0.00%	20.00	1.67%
1997-1999	1,194.47	20.00	1.67%	0.00	0.00%	20.00	1.67%
1998-2000	558.47	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	174.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	3,075.26	20.00	0.65%	0.00	0.00%	20.00	0.65%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.88%
1987-2001	15-Year Trend	1.03%
1992-2001	10-Year Trend	1.11%
1997-2001	5-Year Trend	-0.82%

Adjusted Salvage & C/O/R	**-0.82%**	**0.00%**	**-0.82%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 394.4 - Vehicle Refueling Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	19,508.57	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	29,978.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	4,000.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 394.4 - Vehicle Refueling Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	19,508.57	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	19,508.57	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	19,508.57	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	29,978.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	29,978.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	29,978.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	4,000.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	53,487.51	0.00	0.00%	0.00	0.00%	0.00	0.00%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.00%
1987-2001	15-Year Trend	0.00%
1992-2001	10-Year Trend	0.00%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**0.00%**	**0.00%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 394.5 - Refrigerant Recovery Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	918.31	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 394.5 - Refrigerant Recovery Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	918.31	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	918.31	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	918.31	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	918.31	0.00	0.00%	0.00	0.00%	0.00	0.00%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.00%
1987-2001	15-Year Trend	0.00%
1992-2001	10-Year Trend	0.00%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**0.00%**	**0.00%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 396.2 - Power Operated Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	6,082.85	3,000.00	49.32%	0.00	0.00%	3,000.00	49.32%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 396.2 - Power Operated Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	6,082.85	3,000.00	49.32%	0.00	0.00%	3,000.00	49.32%
1968-2001	6,082.85	3,000.00	49.32%	0.00	0.00%	3,000.00	49.32%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	9.86%
1987-2001	15-Year Trend	13.15%
1992-2001	10-Year Trend	19.73%
1997-2001	5-Year Trend	39.46%

Adjusted Salvage & C/O/R	**39.46%**	**0.00%**	**39.46%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.1- - Communication Equipment (Fixed Radios)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	4,268.84	1,218.75	28.55%	221.37	5.19%	997.38	23.36%
1969	3,445.64	935.44	27.15%	85.25	2.47%	850.19	24.67%
1970	4,976.25	900.00	18.09%	420.66	8.45%	479.34	9.63%
1971	16,544.05	645.21	3.90%	1131.38	6.84%	(486.17)	-2.94%
1972	11,449.22	300.00	2.62%	227.82	1.99%	72.18	0.63%
1973	6,663.21	0.00	0.00%	73.06	1.10%	(73.06)	-1.10%
1974	974.59	93.35	9.58%	354.83	36.41%	(261.48)	-26.83%
1975	13,082.85	325.00	2.48%	513.05	3.92%	(188.05)	-1.44%
1976	15,610.43	250.00	1.60%	1,656.88	10.61%	(1,406.88)	-9.01%
1977	5,173.49	0.00	0.00%	169.08	3.27%	(169.08)	-3.27%
1978	11,897.82	37.50	0.32%	245.12	2.06%	(207.62)	-1.75%
1979	8,974.99	0.00	0.00%	76.60	0.85%	(76.60)	-0.85%
1980	11,715.25	0.00	0.00%	318.16	2.72%	(318.16)	-2.72%
1981	22,186.89	0.00	0.00%	1,115.67	5.03%	(1,115.67)	-5.03%
1982	12,957.15	1,000.00	7.72%	1,891.65	14.60%	(891.65)	-6.88%
1983	20,019.47	3,611.71	18.04%	1,169.79	5.84%	2,441.92	12.20%
1984	6,470.59	155.80	2.41%	322.85	4.99%	(167.05)	-2.58%
1985	12,773.75	0.00	0.00%	825.12	6.46%	(825.12)	-6.46%
1986	14,045.34	834.60	5.94%	1,317.58	9.38%	(482.98)	-3.44%
1987	14,599.85	0.00	0.00%	3,941.11	26.99%	(3,941.11)	-26.99%
1988	5,643.24	180.00	3.19%	1,781.35	31.57%	(1,601.35)	-28.38%
1989	3,624.67	0.00	0.00%	382.38	10.55%	(382.38)	-10.55%
1990	19,000.95	1,378.42	7.25%	603.91	3.18%	774.51	4.08%
1991	31,405.13	854.93	2.72%	(104.91)	-0.33%	959.84	3.06%
1992	20,726.95	918.75	4.43%	213.51	1.03%	705.24	3.40%
1993	2,668.39	(1,317.30)	-49.37%	119.37	4.47%	(1,436.67)	-53.84%
1994	687.33	0.00	0.00%	148.00	21.53%	(148.00)	-21.53%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	29,316.48	0.00	0.00%	347.37	1.18%	(347.37)	-1.18%
1997	420.24	0.00	0.00%	1,227.09	292.00%	(1,227.09)	-292.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.1- - Communication Equipment (Fixed Radios)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	12,690.73	3,054.19	24.07%	727.28	5.73%	2,326.91	18.34%
1969-1971	24,965.94	2,480.65	9.94%	1,637.29	6.56%	843.36	3.38%
1970-1972	32,969.52	1,845.21	5.60%	1,779.86	5.40%	65.35	0.20%
1971-1973	34,656.48	945.21	2.73%	1,432.26	4.13%	(487.05)	-1.41%
1972-1974	19,087.02	393.35	2.06%	655.71	3.44%	(262.36)	-1.37%
1973-1975	20,720.65	418.35	2.02%	940.94	4.54%	(522.59)	-2.52%
1974-1976	29,667.87	668.35	2.25%	2,524.76	8.51%	(1,856.41)	-6.26%
1975-1977	33,866.77	575.00	1.70%	2,339.01	6.91%	(1,764.01)	-5.21%
1976-1978	32,681.74	287.50	0.88%	2,071.08	6.34%	(1,783.58)	-5.46%
1977-1979	26,046.30	37.50	0.14%	490.80	1.88%	(453.30)	-1.74%
1978-1980	32,588.06	37.50	0.12%	639.88	1.96%	(602.38)	-1.85%
1979-1981	42,877.13	0.00	0.00%	1,510.43	3.52%	(1,510.43)	-3.52%
1980-1982	46,859.29	1,000.00	2.13%	3,325.48	7.10%	(2,325.48)	-4.96%
1981-1983	55,163.51	4,611.71	8.36%	4,177.11	7.57%	434.60	0.79%
1982-1984	39,447.21	4,767.51	12.09%	3,384.29	8.58%	1,383.22	3.51%
1983-1985	39,263.81	3,767.51	9.60%	2,317.76	5.90%	1,449.75	3.69%
1984-1986	33,289.68	990.40	2.98%	2,465.55	7.41%	(1,475.15)	-4.43%
1985-1987	41,418.94	834.60	2.02%	6,083.81	14.69%	(5,249.21)	-12.67%
1986-1988	34,288.43	1,014.60	2.96%	7,040.04	20.53%	(6,025.44)	-17.57%
1987-1989	23,867.76	180.00	0.75%	6,104.84	25.58%	(5,924.84)	-24.82%
1988-1990	28,268.86	1,558.42	5.51%	2,767.64	9.79%	(1,209.22)	-4.28%
1989-1991	54,030.75	2,233.35	4.13%	881.38	1.63%	1,351.97	2.50%
1990-1992	71,133.03	3,152.10	4.43%	712.51	1.00%	2,439.59	3.43%
1991-1993	54,800.47	456.38	0.83%	227.97	0.42%	228.41	0.42%
1992-1994	24,082.67	(398.55)	-1.65%	480.88	2.00%	(879.43)	-3.65%
1993-1995	3,355.72	(1,317.30)	-39.26%	267.37	7.97%	(1,584.67)	-47.22%
1994-1996	30,003.81	0.00	0.00%	495.37	1.65%	(495.37)	-1.65%
1995-1997	29,736.72	0.00	0.00%	1,574.46	5.29%	(1,574.46)	-5.29%
1996-1998	29,736.72	0.00	0.00%	1,574.46	5.29%	(1,574.46)	-5.29%
1997-1999	420.24	0.00	0.00%	1,227.09	292.00%	(1,227.09)	-292.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	331,323.05	12,322.16	3.72%	20,795.10	6.28%	(8,472.94)	-2.56%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	-6.05%
1987-2001	15-Year Trend	-4.75%
1992-2001	10-Year Trend	-0.89%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**10.17%**	**-10.17%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.2 - Communication Equipment (Mobile Radios)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	13,364.92	3,815.68	28.55%	0.00	0.00%	3,815.68	28.55%
1969	9,943.12	2,699.56	27.15%	0.00	0.00%	2,699.56	27.15%
1970	16,627.82	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	23,842.75	930.79	3.90%	0.00	0.00%	930.79	3.90%
1972	17,996.82	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	1,994.98	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	35,385.67	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	24,991.44	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	19,776.18	300.00	1.52%	651.23	3.29%	(351.23)	-1.78%
1977	18,362.36	500.00	2.72%	564.45	3.07%	(64.45)	-0.35%
1978	17,518.00	0.00	0.00%	450.43	2.57%	(450.43)	-2.57%
1979	18,151.25	0.00	0.00%	196.94	1.08%	(196.94)	-1.08%
1980	21,016.81	200.00	0.95%	577.03	2.75%	(377.03)	-1.79%
1981	922.51	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	23,451.77	0.00	0.00%	560.61	2.39%	(560.61)	-2.39%
1983	674.00	0.00	0.00%	230.07	34.14%	(230.07)	-34.14%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	1,967.89	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	3,979.89	0.00	0.00%	46.18	1.16%	(46.18)	-1.16%
1987	2,762.25	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	1,740.49	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	2,610.36	0.00	0.00%	115.18	4.41%	(115.18)	-4.41%
1990	42,314.02	0.00	0.00%	2,686.39	6.35%	(2,686.39)	-6.35%
1991	19,627.57	(25.00)	-0.13%	697.93	3.56%	(722.93)	-3.68%
1992	40,455.50	0.00	0.00%	568.48	1.41%	(568.48)	-1.41%
1993	6,710.90	(1,743.45)	-25.98%	27.99	0.42%	(1,771.44)	-26.40%
1994	38,615.39	0.00	0.00%	1,353.16	3.50%	(1,353.16)	-3.50%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	16,136.10	0.00	0.00%	586.87	3.64%	(586.87)	-3.64%
1997	44,503.83	8,249.76	18.54%	580.52	1.30%	7,669.24	17.23%
1998	23,366.54	0.00	0.00%	582.04	2.49%	(582.04)	-2.49%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	1,149.04	0.00	0.00%	13.72	1.19%	(13.72)	-1.19%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.2 - Communication Equipment (Mobile Radios)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	39,935.86	6,515.24	16.31%	0.00	0.00%	6,515.24	16.31%
1969-1971	50,413.69	3,630.35	7.20%	0.00	0.00%	3,630.35	7.20%
1970-1972	58,467.39	930.79	1.59%	0.00	0.00%	930.79	1.59%
1971-1973	43,834.55	930.79	2.12%	0.00	0.00%	930.79	2.12%
1972-1974	55,377.47	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	62,372.09	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	80,153.29	300.00	0.37%	651.23	0.81%	(351.23)	-0.44%
1975-1977	63,129.98	800.00	1.27%	1,215.68	1.93%	(415.68)	-0.66%
1976-1978	55,656.54	800.00	1.44%	1,666.11	2.99%	(866.11)	-1.56%
1977-1979	54,031.61	500.00	0.93%	1,211.82	2.24%	(711.82)	-1.32%
1978-1980	56,686.06	200.00	0.35%	1,224.40	2.16%	(1,024.40)	-1.81%
1979-1981	40,090.57	200.00	0.50%	773.97	1.93%	(573.97)	-1.43%
1980-1982	45,391.09	200.00	0.44%	1,137.64	2.51%	(937.64)	-2.07%
1981-1983	25,048.28	0.00	0.00%	790.68	3.16%	(790.68)	-3.16%
1982-1984	24,125.77	0.00	0.00%	790.68	3.28%	(790.68)	-3.28%
1983-1985	2,641.89	0.00	0.00%	230.07	8.71%	(230.07)	-8.71%
1984-1986	5,947.78	0.00	0.00%	46.18	0.78%	(46.18)	-0.78%
1985-1987	8,710.03	0.00	0.00%	46.18	0.53%	(46.18)	-0.53%
1986-1988	8,482.63	0.00	0.00%	46.18	0.54%	(46.18)	-0.54%
1987-1989	7,113.10	0.00	0.00%	115.18	1.62%	(115.18)	-1.62%
1988-1990	46,664.87	0.00	0.00%	2,801.57	6.00%	(2,801.57)	-6.00%
1989-1991	64,551.95	(25.00)	-0.04%	3,499.50	5.42%	(3,524.50)	-5.46%
1990-1992	102,397.09	(25.00)	-0.02%	3,952.80	3.86%	(3,977.80)	-3.88%
1991-1993	66,793.97	(1,768.45)	-2.65%	1,294.40	1.94%	(3,062.85)	-4.59%
1992-1994	85,781.79	(1,743.45)	-2.03%	1,949.63	2.27%	(3,693.08)	-4.31%
1993-1995	45,326.29	(1,743.45)	-3.85%	1,381.15	3.05%	(3,124.60)	-6.89%
1994-1996	54,751.49	0.00	0.00%	1,940.03	3.54%	(1,940.03)	-3.54%
1995-1997	60,639.93	8,249.76	13.60%	1,167.39	1.93%	7,082.37	11.68%
1996-1998	84,006.47	8,249.76	9.82%	1,749.43	2.08%	6,500.33	7.74%
1997-1999	67,870.37	8,249.76	12.16%	1,162.56	1.71%	7,087.20	10.44%
1998-2000	23,366.54	0.00	0.00%	582.04	2.49%	(582.04)	-2.49%
1999-2001	1,149.04	0.00	0.00%	13.72	1.19%	(13.72)	-1.19%
1968-2001	509,960.17	14,927.34	2.93%	10,489.22	2.06%	4,438.12	0.87%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	4.58%
1987-2001	15-Year Trend	5.79%
1992-2001	10-Year Trend	7.51%
1997-2001	5-Year Trend	-3.99%

Adjusted Salvage & C/O/R	**-3.99%**	**3.33%**	**-7.33%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.3 - Communication Equipment (Telephone)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	83,094.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	3,095.53	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	1,676.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	1,972.12	5.00	0.25%	0.00	0.00%	5.00	0.25%
2000	9,941.00	4,320.00	43.46%	42.60	0.43%	4,277.40	43.03%
2001	2,780.82	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.3 - Communication Equipment (Telephone)

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	83,094.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	86,189.66	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	87,866.07	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	6,744.06	5.00	0.07%	0.00	0.00%	5.00	0.07%
1998-2000	13,589.53	4,325.00	31.83%	42.60	0.31%	4,282.40	31.51%
1999-2001	14,693.94	4,325.00	29.43%	42.60	0.29%	4,282.40	29.14%
1968-2001	102,560.01	4,325.00	4.22%	42.60	0.04%	4,282.40	4.18%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflatic	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	11.76%
1987-2001	15-Year Trend	15.44%
1992-2001	10-Year Trend	22.40%
1997-2001	5-Year Trend	39.47%

Adjusted Salvage & C/O/R			**39.47%**	**0.07%**	**39.41%**
2001 Total	32,110.42	19,094.61			
LESS:					
Schuchart Bldg Eq	29,329.60	19,094.61			
Net Activity	2,780.82	0.00			

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.5 - Supervisory & Telemetering Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	12,254.23	0.00	0.00%	155.60	1.27%	(155.60)	-1.27%
1990	91,571.27	0.00	0.00%	493.66	0.54%	(493.66)	-0.54%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	1,636.00	615.89	37.65%	0.00	0.00%	615.89	37.65%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.5 - Supervisory & Telemetering Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	12,254.23	0.00	0.00%	155.60	1.27%	(155.60)	-1.27%
1988-1990	103,825.50	0.00	0.00%	649.26	0.63%	(649.26)	-0.63%
1989-1991	103,825.50	0.00	0.00%	649.26	0.63%	(649.26)	-0.63%
1990-1992	91,571.27	0.00	0.00%	493.66	0.54%	(493.66)	-0.54%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	1,636.00	615.89	37.65%	0.00	0.00%	615.89	37.65%
1994-1996	1,636.00	615.89	37.65%	0.00	0.00%	615.89	37.65%
1995-1997	1,636.00	615.89	37.65%	0.00	0.00%	615.89	37.65%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	105,461.50	615.89	0.58%	649.26	0.62%	(33.37)	-0.03%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	13.67%
1987-2001	15-Year Trend	13.98%
1992-2001	10-Year Trend	7.53%
1997-2001	5-Year Trend	-15.06%

Adjusted Salvage & C/O/R	**-15.06%**	**1.00%**	**-16.06%**

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.8 - Network Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	794.68	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 397.8 - Network Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969-1971	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970-1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971-1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972-1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973-1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974-1976	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975-1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976-1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977-1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978-1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979-1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980-1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981-1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982-1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983-1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984-1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985-1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986-1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987-1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988-1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989-1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990-1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991-1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992-1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993-1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994-1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996-1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997-1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998-2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999-2001	794.68	0.00	0.00%	0.00	0.00%	0.00	0.00%
1968-2001	794.68	0.00	0.00%	0.00	0.00%	0.00	0.00%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflatic	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	0.00%
1987-2001	15-Year Trend	0.00%
1992-2001	10-Year Trend	0.00%
1997-2001	5-Year Trend	0.00%

Adjusted Salvage & C/O/R			**0.00%**	**0.00%**	**0.00%**
2001 Total	205,388.86	149,917.06			
LESS:					
Schuchart Bldg Eq	204,594.18	149,917.06			
Net Activity	794.68	0.00			

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 398 - Miscellaneous Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	811.33	352.48	43.44%	0.00	0.00%	352.48	43.44%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	453.08	0.00	0.00%	0.00	0.00%	0.00	0.00%
1971	1,043.67	597.00	57.20%	0.00	0.00%	597.00	57.20%
1972	5,784.91	3,265.73	56.45%	0.00	0.00%	3,265.73	56.45%
1973	6,524.82	4,435.90	67.99%	0.00	0.00%	4,435.90	67.99%
1974	10,129.41	6,336.96	62.56%	0.00	0.00%	6,336.96	62.56%
1975	7,148.82	5,238.68	73.28%	0.00	0.00%	5,238.68	73.28%
1976	7,918.10	4,855.70	61.32%	0.00	0.00%	4,855.70	61.32%
1977	10,055.95	5,803.65	57.71%	0.00	0.00%	5,803.65	57.71%
1978	6,522.25	5,774.32	88.53%	0.00	0.00%	5,774.32	88.53%
1979	5,739.82	4,372.17	76.17%	2.13	0.04%	4,370.04	76.14%
1980	8,156.79	6,590.06	80.79%	0.00	0.00%	6,590.06	80.79%
1981	8,686.50	4,687.60	53.96%	0.00	0.00%	4,687.60	53.96%
1982	15,306.50	6,288.72	41.09%	0.00	0.00%	6,288.72	41.09%
1983	1,781.77	1,052.29	59.06%	0.00	0.00%	1,052.29	59.06%
1984	1,993.23	1,425.58	71.52%	0.00	0.00%	1,425.58	71.52%
1985	5,503.43	3,352.75	60.92%	(0.72)	-0.01%	3,353.47	60.93%
1986	267.62	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	1,644.39	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	2;526.95	170.00	6.73%	0.00	0.00%	170.00	6.73%
1989	498.35	162.00	32.51%	0.00	0.00%	162.00	32.51%
1990	1,021.87	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	881.97	331.50	37.59%	0.00	0.00%	331.50	37.59%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	16,886.59	20.00	0.12%	0.00	0.00%	20.00	0.12%
1994	366.88	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	24,976.03	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	5,644.65	424.76	7.53%	0.00	0.00%	424.76	7.53%
1998	1,902.10	53.76	2.83%	0.00	0.00%	53.76	2.83%
1999	160.93	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	922.69	45.00	4.88%	0.00	0.00%	45.00	4.88%
2001	17,870.56	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant

Analysis of Experienced Salvage
1968 through 2001

Account 398 - Miscellaneous Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE - YEAR ROLLING BANDS							
1968-1970	1,264.41	352.48	27.88%	0.00	0.00%	352.48	27.88%
1969-1971	1,496.75	597.00	39.89%	0.00	0.00%	597.00	39.89%
1970-1972	7,281.66	3,862.73	53.05%	0.00	0.00%	3,862.73	53.05%
1971-1973	13,353.40	8,298.63	62.15%	0.00	0.00%	8,298.63	62.15%
1972-1974	22,439.14	14,038.59	62.56%	0.00	0.00%	14,038.59	62.56%
1973-1975	23,803.05	16,011.54	67.27%	0.00	0.00%	16,011.54	67.27%
1974-1976	25,196.33	16,431.34	65.21%	0.00	0.00%	16,431.34	65.21%
1975-1977	25,122.87	15,898.03	63.28%	0.00	0.00%	15,898.03	63.28%
1976-1978	24,496.30	16,433.67	67.09%	0.00	0.00%	16,433.67	67.09%
1977-1979	22,318.02	15,950.14	71.47%	2.13	0.01%	15,948.01	71.46%
1978-1980	20,418.86	16,736.55	81.97%	2.13	0.01%	16,734.42	81.96%
1979-1981	22,583.11	15,649.83	69.30%	2.13	0.01%	15,647.70	69.29%
1980-1982	32,149.79	17,566.38	54.64%	0.00	0.00%	17,566.38	54.64%
1981-1983	25,774.77	12,028.61	46.67%	0.00	0.00%	12,028.61	46.67%
1982-1984	19,081.50	8,766.59	45.94%	0.00	0.00%	8,766.59	45.94%
1983-1985	9,278.43	5,830.62	62.84%	(0.72)	-0.01%	5,831.34	62.85%
1984-1986	7,764.28	4,778.33	61.54%	(0.72)	-0.01%	4,779.05	61.55%
1985-1987	7,415.44	3,352.75	45.21%	(0.72)	-0.01%	3,353.47	45.22%
1986-1988	4,438.96	170.00	3.83%	0.00	0.00%	170.00	3.83%
1987-1989	4,669.69	332.00	7.11%	0.00	0.00%	332.00	7.11%
1988-1990	4,047.17	332.00	8.20%	0.00	0.00%	332.00	8.20%
1989-1991	2,402.19	493.50	20.54%	0.00	0.00%	493.50	20.54%
1990-1992	1,903.84	331.50	17.41%	0.00	0.00%	331.50	17.41%
1991-1993	17,768.56	351.50	1.98%	0.00	0.00%	351.50	1.98%
1992-1994	17,253.47	20.00	0.12%	0.00	0.00%	20.00	0.12%
1993-1995	17,253.47	20.00	0.12%	0.00	0.00%	20.00	0.12%
1994-1996	25,342.91	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995-1997	30,620.68	424.76	1.39%	0.00	0.00%	424.76	1.39%
1996-1998	32,522.78	478.52	1.47%	0.00	0.00%	478.52	1.47%
1997-1999	7,707.68	478.52	6.21%	0.00	0.00%	478.52	6.21%
1998-2000	2,985.72	98.76	3.31%	0.00	0.00%	98.76	3.31%
1999-2001	18,954.18	45.00	0.24%	0.00	0.00%	45.00	0.24%
1968-2001	179,131.96	65,636.61	36.64%	1.41	0.00%	65,635.20	36.64%

Trend Analysis (End Year) 2001

***Based Upon 3-Year Rolling Averages**

Annual Inflatic	2.75%
ASL	40
Avg Ret Age	22.2
Years to ASL	17.8
Inflation Factor At 2.75% to ASL	1.62

Gross Salv. Trend Analysis*		
1982-2001	20-Year Trend	-14.64%
1987-2001	15-Year Trend	-4.86%
1992-2001	10-Year Trend	-0.42%
1997-2001	5-Year Trend	2.38%

Adjusted Salvage & C/O/R			**2.38%**	**0.00%**	**2.38%**
2001 Total	148,046.94	121,549.86			
LESS:					
Schuchart Bldg Eq	130,176.38	121,549.86			
Net Activity	17,870.56	0.00			

APPROVED
DATE: 1-29-03
KMF

MOTION

January 29, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission approve compliance tariff corrections filed January 6, 2003 for service rendered on or after December 12, 2002 under MDU Small Interruptible Rate 71 and Large Interruptible Rate 85 in the application of Montana-Dakota Utilities Co. for an increase in Natural Gas Rates, Case No. PU-399-02-183.

JRL/sdh

115 PU-399-02-183 Pages: 1

Motion approving tariff corrections

by Public Service Commission

01/29/2003 CC: Comm Legal Illona, Pat, Jerry Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **16th day of January, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with fully prepaid, securely sealed and each containing a photocopy of:

Staff Response to Compliance Filing

The envelope were addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

William Pearce
P O Box 400
Bismarck ND 58502-0400

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sandra L Scott

Subscribed and sworn to before me
this **16th day of January, 2003**.

Susan K. Richter
Notary Public

SEAL

SUSAN K. RICHTER
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 15, 2004

114 **PU-399-02-183** Pages: 1

Affidavit of Service

by Public Service Commission

01/16/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

RECEIVED
JAN 15 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

STAFF RESPONSE TO COMPLIANCE FILING

January 15, 2003

On December 16, 2002, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) filed tariff changes to comply with the Order of the Commission dated December 10, 2002. On January 6, 2003, MDU filed a correction to the Small Interruptible Rate 71 and the Large Interruptible Rate 85.

The changes are necessary because of the new rate design that recovers the gas costs and the distribution costs in separate rate elements. In its original application, MDU overlooked the effects of the new rate design on the tariffed rates for these customers. The January 6, 2003 filing is therefore made to maintain the same quantity of margin sharing ($0.444 per dekatherm) previously approved by the Commission in Case No. PU-399-94-352.

Staff believes that MDU's filing complies with the Commission's Order.

William W. Binek
Chief Counsel

113 PU-399-02-183 Pages: 1
Staff Response to Compliance Filing
by Public Service Commission
01/15/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

RECEIVED
JAN - 6 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

January 6, 2003

Executive Secretary
North Dakota Public Service Commission
State Capitol
Bismarck, ND 58505-0480

Re: Case No. PU-399-02-183
Tariff Correction

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits an original and seven copies of the following tariff sheets:

- 2nd Revised Sheet No. 14, Small Interruptible General Gas Service Rate 71
- 1st Revised Sheet No. 27, Large Interruptible General Gas Service Rate 85

The tariffs referenced above have been filed in order to reflect the correct ceiling rate under each rate which should reflect the margin sharing amount originally authorized in Case No. PU399-94-352. The calculation is as shown on Attachment A. Montana-Dakota requests that the tariff sheets attached be effective with service rendered on and after December 12, 2002. Adjusted bills will be issued to any customer billed under the incorrect ceiling rate.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto.

Sincerely,

Donald R. Ball

Donald R. Ball
Directory of Regulatory Affairs

112 PU-399-02-183 Pages: 4
Tariff correction
by Montana-Dakota Utilities Co., a Division of MDU
01/06/2003 CC: Comm Legal Illona, Pat, Jerry Mil

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
2nd Revised Sheet No. 14
Canceling 1st Sheet No. 14

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$100.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$.871 per dk	$.427 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the cost of Purchased Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 27
Canceling Original Sheet No. 27

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

This rate schedule shall not apply for service to U.S. Government installations, which are covered by separate special contracts.

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge	$675.00 per month	
Distribution Delivery Charge	Maximum $.719 per dk	Minimum $.298 per dk
Cost of Gas	Determined Monthly- See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

North Dakota Margin Sharing
Interrupible Sales Rates

Authorized PU-399-94-352

	Rate 71	Rate 85
Ceiling Rate	$3.500	$3.290
Base Cost of Gas	2.548	2.548
Effective Margin	0.952	0.742
Floor Rate	$3.056	$2.869
Base Cost of Gas	2.548	2.548
Effective Margin	0.508	0.321
Margin Shared	$0.444	$0.421

PU-399-02-183
Rates Authorized 12/12/02
Distribution Delivery Charges Only

	Rate 71	Rate 85
Authorized Floor	$0.427	$0.298
Margin Shared	0.444	0.421
Effective Ceiling Rate	$0.871	$0.719

Scott, Sandi L.

From: Bauske, Shelly A.
Sent: Friday, December 27, 2002 1:33 PM
To: Scott, Sandi L.
Subject: FW: Money Received.....

-----Original Message-----
From: **Geiger, Gloria A.**
Sent: Friday, December 27, 2002 1:29 PM
To: Bauske, Shelly A.
Cc: Geiger, Gloria A.
Subject: RE: Money Received.....

Gloria Geiger
North Dakota Public Service Commission
600 E Boulevard 13th Floor Dept 408
Bismarck, ND 58505-0480
701-328-2401
fax 701-328-2133
gag@psc.state.nd.us

-----Original Message-----
From: **Bauske, Shelly A.**
Sent: Friday, December 27, 2002 11:12 AM
To: Geiger, Gloria A.
Subject: Money Received.....

Case No. PU-2463-02-340
Integra Telecom
$55.24

7700	8503	248	22339	$18.70
7700	8503	248	22287	$36.54

Case No. PU-2077-02-308
Western Wireless
$334.84

this was paid on 11/20/02

Case No. PU-2768-02-415
United Telephone (for Turtle Mountain)
$18.69

7700 8503 248 22339

Case No. PU-399-02-183
MDU
$16,182.60

12 **PU-2463-02-340** Pages: 0

$55.24 received

by Integra Telecom of North Dakota, Inc.

12/27/2002 CC: Comm Legal Illona Jerry .

76 **PU-2077-02-308** Pages: 0

$334.84 received

by Western Wireless

11/20/2002 CC: Comm Legal Illona Pat .

12 **PU-2768-02-415** Pages: 0

$18.69 received

by Turtle Mountain Communications, Inc.

12/27/2002 CC: Comm Legal Illona Jerry .

✓ **111** **PU-399-02-183** Pages: 0

$16,182.60 received

by Montana-Dakota Utilities Co., a Division of MDU

12/27/2002 CC: Comm Legal Illona, Pat, Jerry Mil

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

December 19, 2002

Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Dear Mr. Ball:

On December 18, 2002, the Commission approved the rates filed in compliance with the Commission's December 10th order in Case No. PU-299-02-183, Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application.

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

Enclosure

110 **PU-399-02-183** Pages: 1

Letter to MDU re approval of rates

by Public Service Commission

12/19/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

APPROVED
DATE: 12-18-02
KMF

MOTION

December 18, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission approve tariff changes effective for service rendered on or after December 12, 2002 filed in compliance with the Commission's December 10th Order in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application, Case No. PU-399-02-183.

JRL/sdh

109 **PU-399-02-183** Pages: 1

Motion approving rates

by Public Service Commission

12/18/2002 CC: Comm Legal Illona, Pat, Jerry Mike

APPROVED
DATE: 12-18-02
KMF

MOTION

Admin
A1.

December 18, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission bill Montana-Dakota Utilities Co. for costs incurred to date in Case No. PU-399-02-183, Montana-Dakota Utilities Co., Natural Gas Rate Increase, Application.

108 PU-399-02-183 Pages: 3
Utility Valuation
by Public Service Commission
12/19/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

December 18, 2002

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

RE: Case No. PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the December 18, 2002 Public Service Commission meeting for the expenses incurred to date in Case No. PU-399-02-183.

Under N.D.C.C. 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Administrative Staff Officer
701-328-2401

Enc.

Billing Statement

December 18, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

Expenses Incurred to Date:

Consulting Services	$14,691.93
Office of Administrative Hearings	1,490.76

Amount Due:

Montana-Dakota Utilities Co.	$16,182.69

Send Payment and a Copy of this Statement To:

Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **19th day of December, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Findings of Fact, Conclusion of Law, and Order

The envelope were addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 1940 0005 3425 2368

William Pearce
P O Box 400
Bismarck ND 58502-0400
Cert. No. 7001 1940 0005 3425 2375

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 1940 0005 3425 2382

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **19th day of December, 2002.**

Sandra L Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **19th day of December, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Findings of Fact, Conclusions of Law, and Order

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **19th day of December, 2002**.

Sandra L. Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

F James Moriarty
2333 Plum Grove Dr
O'Fallon MO 63366

Steven Tomac
2498 59th St
St Anthony ND 58566-9640

Will Kaul
Cooperative Power Association
P O Box 800
Elk River MN 55330-0800

Patricia Estes
Daily News
PO Box 760
Wahpeton ND 58074-0760

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Frank Morehouse
Great Plains Natural Gas Co
PO Box 176
Fergus Falls MN 56548-0176

Jay Casler
INDEPTH DATA INC
211 N Robinson Ave Ste S-1500
Oklahoma City OK 73102-7101

Karyn Grass
IPAMS
6620 Denver Club Bldg 518 17th St
Denver CO 80202-4167

Rick Jensen
KHND AM Radio
PO Box 6
Harvey ND 58341-0006

Kelley Richardson
King Publishing Co
PO Box 52210
Knoxville TN 37950-2210

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

Minnesota PUC
121 E 7th Pl Ste 350
St Paul MN 55101-2147

C W Fox
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Ron Tipton
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

Robert Burns
National Regulatory Research Inst
406 Bevis Hall 1080 Carmack
Columbus OH 43210

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Scott Speaker
Natural Gas Week
1401 New York Ave NW Ste 500
Washington DC 20005-2150

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Jamie Seitz
Xcel Energy
825 Rice St
St Paul MN 55117

Paul Lehman
Xcel Energy
512 Nicollet Mall
Minneapolis MN 55402

ccano@mh.com
Craig Cano
Gas Utility Report
1200 G St NW Ste 1100
Washington DC 20005

inland@btigate.com
Inland Oil & Gas Corp
PO Box 1313
Bismarck ND 58502-1313

jason_gustafson@bobcat.com
Jason Gustafson
Melroe Company
P O Box 128
Gwinner ND 58040-0128

craig_scott@bobcat.com
Craig Scott
Melroe Company
P O Box 128
Gwinner ND 58040-0128

tom.hopgood@mduresources.com
Tom Hopgood
Montana-Dakota Utilities Co

balld@mdu.mdures.com
Don Ball
Montana-Dakota Utilities Co
400 N 4th St
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APPROVED
DATE: 12-18-02
KMF

MOTION

December 18, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission adopt the Corrected Order, correcting the date in Ordering Paragraph No. 3 from January 31, 2002 to January 31, 2003, in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application in Case No. PU-399-02-183.

sdh

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Motion adopting Corrected Order

by Public Service Commission

12/18/2002 CC: Comm Legal Illona, Pat, Jerry Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

CORRECTED FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

December 18, 2002

Appearances

Commissioners: Susan E. Wefald, Leo M. Reinbold, Anthony T. Clark.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy staff.

William P. Pearce, Attorney at Law, 314 E. Thayer Ave., PO Box 400, Bismarck, ND 58502-0400, appearing for Montana-Dakota Utilities Co.

Douglas W. Schulz, Senior Attorney, MDU Resources Group, Inc., PO Box 5650, Bismarck, ND 58506-5650, appearing for Montana-Dakota Utilities Co.

Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

On April 12, 2002, the North Dakota Public Service Commission received an application from Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) to increase its natural gas rates 4.1%. The requested increase in rates would generate an additional $2,844,132 annually in North Dakota. MDU's application is based on a calendar 2003 projected test year.

MDU stated that the primary reasons for its application are increased operation and maintenance costs, depreciation, and taxes other than income, and a higher required rate of return. MDU's requested return on rate base is 11.044 percent, including a return of 13.25 percent on common equity.

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Corrected Findings of Fact, Conclusions of Law and Order by Public Service Commission

12/18/2002 CC: Comm Legal Illona, Pat, Jerry Mike

In its application, MDU also requested a significant restructuring of its rates, including a separation of gas distribution from gas supply charges, elimination of declining block commodity charges and increases in customer charges. Additionally, MDU proposed that all increases be flowed into the firm residential and commercial rate schedules, that no change in rate levels be applied to the Air Force and large interruptible schedules, and that the small interruptible class should receive a rate reduction.

On April 24, 2002, the Commission suspended MDU's rates filed with its application. On June 5, 2002, the Commission issued its Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline.

The Notice of Hearing specified the issues to be considered at the technical hearing, which are:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

The Notice of Hearing provided that any person wishing to intervene as a party in the proceeding must file a petition for intervention by September 9, 2002. No one petitioned to intervene as a party in the proceeding.

Public input sessions were held via video teleconference on July 15, 2002, in Bismarck, Dickinson, Williston, Minot, Devils Lake, and Jamestown. The technical hearing was held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota on October 7-8, 2002.

On December 6, 2002 MDU filed a letter indicating its understanding of and agreement with the continuation of the depreciation issue, as more fully set forth below.

The Commission, having reviewed the evidence in the record makes the following:

Findings of Fact

1. MDU is an investor owned utility company providing natural gas distribution service in North Dakota operating as a division of MDU Resources Group, Inc.

2. The parties do not dispute the following issues:

- 2003 test year for rate determination.
- Jurisdictional cost of service study.
- 2003 test year for rate base (except accumulated reserve for depreciation)
- Cost of preferred equity.
- Test year revenues.

3. The parties dispute the following issues:

- Cost of capital
- Depreciation
- Bonuses and labor expenses
- Supplemental Income Security Plan
- Rate case expense
- General inflation adjustment for expenses
- Other unadjusted operation and maintenance expenses
- Allocation of cost to customer classes
- Rate design (partially)
- Distribution Delivery Stabilization Mechanism

Test Year Rate Base

4. MDU and Staff are in agreement on the amount of rate base for the 2003 test year with the exception of accumulated reserve for depreciation. The staff adjustment to accumulated reserve for depreciation is affected by a staff adjustment to depreciation expense of $2,172,000. For reasons discussed later, the Commission does not accept staff's adjustment and finds that MDU's projected rate base for 2003 is reasonable.

5. The Commission finds the following 2003 test year rate base:

Rate Base	*(Thousands)* Balance
Plant in Service	$ 72,793
Accumulated Depreciation	49,356
Net Plant	$ 23,437
Materials and Supplies	439
Fuel Stocks	22
Prepayments	84
Other	44
Accumulated Deferred Taxes	(3,842)
Accumulated ITC's	(231)
Customer Advances	(272)
Average Rate Base	$ 19,681

Cost of Capital

6. MDU proposes a rate of return of 11.044 percent, which includes a 13.25 percent return on common equity. Staff has recommended a return of 7.98 percent, including a 10.5 percent return on common equity, inclusion of short-term debt financing and a company wide cost of long-term debt. The rates of return can be calculated as follows:

7. As demonstrated in the foregoing tables, the Staff differs from MDU with respect to the appropriate capital structure as well as the cost of the financing.

Capital Structure

8. Capital structure refers to the makeup of MDU's capital, that is, the mix of debt, preferred stock and equity. Two factors account for the disagreement between Staff and MDU. The first is Staff's inclusion of short-term debt, and the second is Staff's use of the year-end 2001 capital structure instead of MDU's projected capital structure for 2003.

9. In its initial filing, MDU excluded all short-term debt from its proposed capital structure. Staff's rate of return witness, Charles W. King, testified that the makeup of the capital structure used to develop a rate of return should reflect the nature of the rate base to which that return is applied. If the rate base consists solely of capital investments in plant and equipment financed by long-term debt, preferred stock and equity, then it might be appropriate to exclude short-term debt. But MDU's rate base also includes materials and supplies inventories, fuel stocks, and prepayments, which are short-term commitments that will be financed in part with short-term debt. For this reason, he included short-term debt in the capital structure.

10. On rebuttal, MDU witness Craig Keller argued that the items to which King referred, materials and supplies, prepayments and fuel stocks remain relatively constant, not changing materially from one month to another. While classified as short-term assets, they support long-lived assets such as plant, property, equipment and related items. They are therefore financed by long-term debt, according to Keller.

11. At the hearing, King responded to Keller by producing Exhibit 16, which shows the month-to-month amounts of each of the major elements of working capital during the 13 months from December 2000 through December 2001. That exhibit demonstrates net working capital varied from negative $53,000 in January to positive $306,000 in July. King concluded that these widely varying amounts would not have been financed with long-term debt. Keller argued that an unusual refund of a customer advance caused much of the variation shown by King.

12. The Commission finds that MDU has short-term debt and therefore finances part of its business with short-term debt. Accordingly, the Commission will include short-term debt in the determination of cost of capital.

13. The second difference in proposed capital structures relates to the use of historical verses forecasted data. King drew the amounts of debt, preferred stock and common equity from Company supplied data for calendar year 2001. He calculated average long-term debt from Exhibit 2, Statement A, page 2; short-term debt from a response to a data request (Exhibit 15, CWK-1); and preferred stock and common equity from Exhibit 2, Statements A and F, page 1.

14. The capital structure presented by MDU on Statement F, page 3 includes a projected 2003 capital structure. King objected to this use of a projection on the grounds that it is effectively a creation of MDU that has no basis in any verifiable financial statements.

15. On rebuttal, MDU witness Keller argued that NDCC § 49-05-04.1 permits MDU to use a forecast test year and that Staff witness, Michael J. Majoros, had accepted the 2003 test year as the basis for revenue requirements. Keller argued that failure to use a forecast capital structure would result in a "mismatch" with the rest of the revenue requirement calculation. Keller argued that MDU possesses a financial forecasting system that uses known debt scheduling and projects equity by forecasting earnings and deducting dividends.

16. In his oral direct testimony, King pointed out that MDU had used an historical capital structure in its recent electric case. He argued that the purpose of the future test year is to capture exogenous changes that can be objectively determined, such as inflation or the expansion of the system. There is no way of verifying that it will change in the manner MDU predicts. For this reason, King reasoned that most Commissions use recent historical capital structures. Otherwise, MDU has the opportunity to game the regulatory system by projecting a more expensive capital structure.

17. Regarding the issue of historical verses projected, we find in favor of MDU. North Dakota law provides for using a projected test year. There are no assurances that revenues, expenses or cost of capital will actually occur at projected levels. However, the staff's case is predicated on projected revenues and expenses but ignores cost of capital projections. The Commission finds in favor of using a projected capital structure rather than relying on general allegations that MDU might game the regulatory system.

Cost of Debt

18. MDU's cost of debt in 2001 is 9.302 percent, and its projected 2003 debt cost is 9.180 percent. These values are calculated on Exhibit 2, Statement F-1, pages 1 and 3. Those pages show two debt issues, First Mortgage Bonds and Pollution Control Bonds, totaling $133.5 million in 2001 and $132.6 million in 2003.

19. Statement A, pages 11 and 12 of that same exhibit reveals that there is substantially more to MDU's debt than these two issues. As of December 31, 2001, there were $405.2 million in senior notes, $219.7 million in commercial paper, a revolving line of credit of $25 million, and term credit agreements of $11.8 million. Using the cost values shown on those pages, King calculated that the blended cost of MDU's debt is 6.167 percent, more than 300 basis points lower than MDU proposes.

20. The difference between Staff and MDU revolves around what "the Company" actually is. According to MDU witness Keller, only the First Mortgage and Pollution Control bonds relate to MDU Utilities. He argues that all of the other debt pertains to Centennial Holdings, which holds title to the non-regulated operations of the parent Company, MDU Resources Group, Inc. He stated that the two sets of debt are not fungible, and assets of Centennial do not secure the first mortgage liens against electric and gas plant nor do the assets of the utility operations secure the liens against non-regulated assets. Under Keller's argument, MDU has no access to Centennial's debt and vice versa. Further, MDU asserted that it was unfair of staff to use the low cost of a blended rate and ignore the higher cost of a blended capital structure with an equity ratio of nearly 60%.

21. On cross-examination, Keller made it clear that there is no such entity as the Montana-Dakota Utilities Company. The only legal entity is the parent Company, MDU Resources Group, and only that company can issue debt. Neither the utility operation nor Centennial has any debt in its own right. Keller testified that MDU had attempted to build a "firewall" between the debts of MDU Utilities and that of Centennial. The purpose is to protect the utility operations from the effect of default on Centennial's debt. He stated that if Centennial or one of its subsidiaries should go bankrupt, then the bankruptcy judge would not be able to "collapse the corporation" and gain access to the utility's assets. Keller stated that is the reason MDU does not commingle the funds raised for the utility with those raised for Centennial.

22. On cross-examination, Keller conceded that if the bankruptcy of either MDU's regulated or its unregulated operations caused the parent to declare bankruptcy, then

the bankruptcy court would look at all of MDU's assets to satisfy creditors' claims, including those of the regulated utility.

23. King suggested that there might be another, less altruistic reason for attempting to isolate Centennial's debt from that of the utility operations. It is to ensure that ratepayers pay the very high costs of the First Mortgage bonds and receive no benefit from the Company's other, lower-cost financing resources. While the Company may have written its low-cost financing instruments to direct funds to Centennial and its subsidiaries, that was an artifice to game the regulatory system into ascribing only the highest cost debt to regulated service ratepayers. The Company could have used the Centennial funds anywhere had it written the debt instruments differently.

24. MDU's cost of debt is higher than the cost of debt reported by the other investor owned utilities operating in North Dakota. Further, it is nonsensical that the non-regulated enterprises of MDU and thereby more riskier ventures of the corporation are able to secure debt at substantially lower cost than its regulated counterpart. The timing of debt issuances may account for some differences year-to-year but overall and in the long-term one would expect that the cost of debt for the utility operations would be less and certainly not more than 300 basis points higher than the company wide average. Still, the Commission begrudgingly finds in favor of MDU based on the fact that staff was unable to show that MDU had gamed the regulatory system. Such a showing would require an analysis of the timing of plant in service additions compared to the timing of debt issuances before such a verdict could be rendered. Accordingly, the Commission finds in favor of MDU and agrees to use its proposed cost of long-term debt in this proceeding.

Cost of Equity

25. MDU's rate-of-return witness, Dr. J. Stephen Gaske, has recommended a return to equity of 13.25 percent. This return was developed using three variants of the Discounted Cash Flow ("DCF") approach, plus a series of "benchmark analyses."

26. For his DCF results, Gaske drew a distinction between "Investor Requirements" and "Cost of Capital" based on his belief that stock flotation costs, equivalent to 4.75 percent of the return, must be included in the latter. Gaske used a "proxy group" of six companies based on Moody's utility series. His DCF results for these companies were as follows:

	Investor Requirements	**Cost of Capital**
Second-stage Retention Growth	11.94%	12.51%
Basic DCF	12.61%	13.21%
Primary DCF	12.63%	13.22%

27. Gaske's benchmark analyses consisted of four risk premium comparisons using historical differences in earned returns to equity from large and, alternatively, small companies relative to current yields on U.S. Treasury bonds and corporate bonds. He

also identified the recent returns on per-share book value of S&P 500 corporations and Value Line's list of industrial companies. All of his benchmark indicators were higher than any of his DCF returns.

28. Gaske's final selection of 13.25 percent was based on his belief that the risk of MDU's gas distribution business is slightly higher than that of his proxy group of gas distribution companies. He based this belief principally on the smaller size of MDU relative to the proxy companies.

29. King recommended a very different return to equity of 10.5 percent. King followed most of the same procedures as Gaske using the DCF analyses as the principal analytical tool. Like Gaske, King used a comparison group of gas distribution companies. Also like Gaske, King used a forecast of next year's dividends for the dividend yield portion of the DCF formula. King also used both analysts' forecasts and the concept of earnings retention to calculate the growth component of that formula -- as did Gaske. Finally, both King and Gaske adjusted their final recommendations based on their assessments of the risk of MDU's gas distribution activities relative to that of the comparison companies.

30. The explanation for the dramatic 275 basis points difference between the recommendations of the two witnesses lies in the details of the application of the DCF formula. As used by both witnesses, the DCF formula is the sum of next year's dividend yield on MDU's stock and the expected future growth rate in its dividends and earnings.

31. The differences between the Gaske and King applications of the DCF formula relate to the following elements:

1. Inclusion of flotation costs;
2. Selection of comparison companies;
3. Forecast of next year's dividends;
4. Timing of analysts' forecasts;
5. Presentation of the DCF results.

Flotation Costs

32. Gaske drew a distinction between "investor requirement" and "cost of capital," with the difference being cost of issuing new shares in public stock offerings. Gaske quantified this cost as 4.75 percent, based on a representative sample of flotation costs incurred with 34 new common stock issues by natural gas transmission and distribution companies between 1992 and 2001.

33. King agreed with Gaske that flotation costs should be recovered, but he questioned the propriety of applying a ratio for these costs to the entire amount of common equity. Flotation costs are incurred only when a company issues new stock, and then only when there is a public stock offering. Existing stock incurs no flotation cost, and even new stock incurs no such costs if it is distributed as an employee or shareholder benefit either through options or as bonuses.

34. King noted that the effect of Gaske's flotation cost adjustment is to increase his equity return by 60 basis points. When multiplied by the $1.125 billion book equity value of the MDU Resources, Inc., this allowance amounts to $6.75 million annually, which is substantially more than the $5.4 million in flotation costs that the Company has incurred over the past five years.

35. King suggested that if a flotation cost adder is to be used, it should be equal to a reasonable estimate of the annual flotation cost incurrence divided by the entire amount of the Company's equity. In MDU's case, annual flotation costs during the past five years have been about $1.1 million. The Company's total book equity value is $1.125 billion, for a flotation cost allowance of 0.1 percent. This amount is so small as to be lost in the rounding. For this reason, he recommended no explicit flotation cost adder.

36. In rebuttal, Gaske distributed an exhibit that purported to demonstrate that failure to include flotation costs in the return of a company's stock trading at book value would result in the dilution of the book value of that company's shares. On cross-examination, however, Gaske admitted that all of King's comparison companies had per-share market values higher than book value, and that when such companies sell new stock, the effect is to increase book value, not dilute it. On cross-examination, Gaske admitted that his approach to the issue of flotation cost in this proceeding was the same as his approach in Commission Case No. PU-399-01-186 involving MDU's electric rates. Gaske also agreed that most regulatory Commissions do not allow a flotation cost adder.

37. The Commission rejects Gaske's flotation cost adder. Given that staff has provided evidence based on historical information, we find no need to rely on the theoretical information provided by MDU. In addition, Gaske admitted that most regulatory Commissions do not allow flotation costs. The evidence indicates a negligible amount of flotation costs were incurred during the last five years. Therefore, the Commission will not include flotation costs in the determination of return on common equity.

Selection of Comparison Companies

38. Both King and Gaske acknowledged that the heavy involvement of MDU's parent company, MDU Resources Group, Inc., in non-regulated activities effectively precluded using similar companies as the basis for finding the return to equity of its gas distribution business in North Dakota. Necessarily, this required the selection of companies whose primary business is gas distribution. Gaske picked six companies from Moody's list of natural gas distribution companies. King chose 11 companies from Value Line's Investment Survey based on the criteria that they must have investment grade bond ratings, total operating revenues over $100 million, and derive 75 percent of their revenue from gas distribution services. The two lists are as follows:

King Comparison Companies	Gaske Proxy Group
Atmos Energy Corp.	AGL Resources
AGL Resources	Keyspan Corporation
Cascade Natural Gas Corp.	LaClede Group
LaClede Group, Inc.	Northwest Natural Gas
NICOR, Inc.	People's Energy Corp.
Northwest Natural Gas Co.	WGL Holdings, Inc.
People's Energy Corp.	
Piedmont Natural Gas Co.	
South Jersey Industries, Inc.	
Southwest Gas	
WGL Holdings, Inc.	

39. Five of Gaske's six companies are also represented on King's list. The exception is Keyspan Corporation, which King excluded because that company's gas distribution operations accounted for only about one-half of its revenue. We find that King's choice of companies provides a broader and therefore more representative group of companies from which to draw indications as to the cost of equity for gas distribution operations.

Forecast of Next Year's Dividends

40. Both King and Gaske used a forecast of next year's dividends to identify the dividend yield portion of the DCF formula, and both witnesses based this forecast on a percentage of the 5-year annual earnings growth rate predicted by Zacks Investment Research, Inc. Only the percentage differed. King used a factor 1.5 on the assumption that the next dividend increase would be randomly distributed over the coming year. Gaske used a 1.625 inflator of the growth rate and argued that King's factor does not reflect the present value of next year's dividends and dividend increases. The issue is immaterial and the Commission adopts Gaske's inflation factor.

Timing of Analysts' Forecasts

41. Gaske's testimony was filed on April 12, 2002, concurrently with MDU's initial application for an increase in its gas rates. The record does not disclose when Gaske prepared his testimony, but presumably it was in the months immediately preceding the application, which would be February and March of 2002. This would be consistent with the fact that the latest month shown on Gaske's presentation of bond yields is January 2002.

42. King filed his testimony on August 30, 2002, so his information on such factors as share prices and investor expectations was gathered approximately six months after Gaske's.

43. It is not clear how these differences in timing affect the results of the respective analyses. For example, Gaske reported Zacks' consensus 5-year earning growth

forecast for the LaClede Group as 12.0 percent. By the time King prepared his testimony, that forecast had dropped to 4.25 percent. On the other hand, Gaske's forecast growth rate for AGL Resources was 7.03 percent, while that reported by King was 11.42 percent. We find it is appropriate to use King's data because it is more current.

Presentation of the DCF Results

44. Gaske performed three different DCF analyses of his proxy group of companies. One of these analyses, the "basic DCF," was identical to King's "classic DCF" analysis. Both involved combining the forecast dividend yields with Zacks' 5-year consensus forecasts of earning growth.

45. While the methods were the same, the results were quite different. Gaske's six-company proxy group yielded a median basic DCF return, prior to flotation costs, of 12.61 percent and a mean return of 12.95 percent. King, applying exactly the same procedure to his comparison group of 11 companies, found the average (mean) to be 11.29 percent.

46. For his other application of the DCF approach, King added the dividend yield to the growth rate indicated by the earnings retention growth model for each of his 11 comparison companies and found the average to be 12.18 percent. Had Gaske done the same thing, he would have added his average dividend yield of 5.14 percent to his retention growth estimate of 5.5 percent for a DCF return indication of 10.64 percent.

47. Gaske diluted his retention growth rate by mixing it one-third, with two-thirds represented by the Zacks' 5-year earnings forecasts. The result was quite close to the "basic" DCF indications. The median of his "Second-Stage Retention Growth DCF Calculation" was 11.94 percent, the mean 12.25 percent.

48. Gaske presented a third version of the DCF analysis. Gaske put forth what he called his "primary" DCF calculation. This was no calculation at all, but merely the adoption of a range of growth estimates with little support. The range was 6.75 percent to 7.75 percent, asserted by Gaske to have been based on such factors as the 5.5 percent growth in nominal Gross Domestic Product during the past decade, the expected demand growth for natural gas, and investor expectations. None of these considerations support a growth forecast in the range of 6.75 percent to 7.75 percent. The bottom of this range is well above the 5.5 percent GDP growth rate cited by Gaske as well as the 5.5 percent growth indicated by his own earnings retention calculation. The top of the range is above the 7.56 percent growth rate predicted by Zacks for the six companies used by Gaske. This "primary" DCF analysis is biased upward.

49. King also presented a third DCF calculation, but he subsequently discarded it. King calculated a growth factor for each of his 11 comparison companies based on the each company's historical earnings growth between 1997 and 2001. While the average DCF indication of 11.72 percent might appear reasonable, the variation among the individual company observations was so great as to provide little or no probative value.

50. In presenting his DCF returns, King went one step further than Gaske, and provided his estimate of the DCF return requirements of each of his comparison companies. He did not use a mechanical formula because, as he conceded in his testimony, precision is impossible. He described his procedure orally at the hearing as follows:

> ...what I have done in each case is taken the classic DCF return, which is probably the best estimator, and then turned and looked at the retention growth method. If the retention growth looks like it's totally out of whack with the forecast, and in some cases they are – simply no way that the company could be growing as fast or as slowly as the investor survey shows – I modified that classic DCF in the direction of the retention growth.

51. The results of King's procedure were as follows:

	Classic	**Book Value Growth**	**King DCF Return**
Atmos Energy Corp.	12.06%	14.42%	12.5%
AGL Resources	16.67%	11.53%	14.0%
Cascade Natural Gas Corp.	10.25%	15.11%	11.0%
LaClede Group, Inc.	10.29%	11.23%	10.5%
NICOR, Inc.	11.51%	15.96%	12.0%
Northwest Natural Gas Co.	10.65%	10.12%	10.5%
People's Energy Corp.	13.13%	12.07%	12.5%
Piedmont Natural Gas Co.	9.42%	11.24%	10.0%
South Jersey Industries, Inc.	8.15%	12.57%	11.0%
Southwest Gas	10.52%	8.53%	10.0%
WGL Holdings, Inc.	8.99%	11.21%	9.5%
Average	**11.29%**	**12.18%**	**11.23%**

52. Gaske rebutted the fact that the average of King's selected DCF results was lower than the average of either his classic or his book value growth results. This mathematical result stems from King's shrinking of the range of observations. King reduced the effect of the "outlier" highest and lowest observations. In absolute terms, the outliers on the high side diverge more from the mean than those on the low side, even when their percentage difference from the mean is the same. This mathematical distortion can be avoided by focusing on the median observation of each series, that is, the observation where five values are higher and five are lower. The classic DCF median return is 10.52 percent, the median of the book value growth series is 11.53 percent, and the median of King's selected DCF returns is 11.0 percent. Additionally, it should be noted that in arriving at his final DCF recommended returns, King adjusted seven of the classic returns upward and only four downward.

53. On rebuttal, Gaske submitted two mechanical recalculations of King's DCF results, one using a 33%/67% weighting of the book value growth and Zacks' forecasts, the other using a 50%/50% weighting. Both yielded average returns considerably higher than King's 11.23 percent. In performing these calculations, however, Gaske excluded WGL Holdings, ostensibly because, with 74.6 percent of its revenue from regulated gas distribution, it falls outside King's 75 percent criterion. As Gaske admitted on cross-examination, 74.6 percent rounds up to 75 percent. His exclusion biased the results upward because, at 8.99 percent, WGL Holdings' classic DCF return was the lowest in King's comparison group. Moreover, Gaske never explained why his mechanical weightings of King's DCF results were more accurate or valid than King's analysis.

54. Both witnesses support the use of DCF for calculating a reasonable return on equity for purposes of this proceeding. Both provided a basic DCF calculation using the same method even though there are some differences in sample sizes and the age of data. Beyond the calculation of basic DCF, both witnesses make adjustments for their own professional judgment and then are highly critical of each other's results. We find the adjustments for professional judgment are not all that intuitive and appear to be aimed at results rather than fact-finding. Accordingly, we find the use of the basic DCF calculations most useful.

Comparative Risk Adjustments

55. King and Gaske disagree about the final adjustment each witness made to the DCF returns for his comparison companies to reflect the specific risk of MDU's gas distribution operations.

56. Having found that the DCF cost of capital (inclusive of flotation cost) for his proxy companies was in the range of 12.51 and 13.22 percent, Gaske selected 13.25 percent as MDU's capital cost. This upward adjustment from the range of proxy group returns was based on Gaske's belief that MDU's overall risks are slightly above average relative to the proxy group.

57. King's adjustment was in the opposite direction. Having found that the average DCF return for his comparison group is 11.23 percent, King picked 10.5 percent for MDU, which is the midpoint between the group average return and the returns for the least risky companies in the group. The basis of this adjustment was King's belief that MDU is less risky than the comparison group.

58. In his initial testimony, Gaske discussed four types of risk: business risk, regulatory risk, financial risk and market risk. He found that MDU's regulatory and market risks are not significantly different than from those of his proxy group. MDU's financial risk is slightly greater because the bonds of MDU Resources Group are rated slightly lower than the bonds of the proxy companies. The major difference in risk, according to Gaske, relates to business risk. MDU's gas distribution operations are a fraction the size of the proxy companies. Those companies are between six and 46 times the size of MDU's gas distribution operations. Based on the historical difference

between the earned returns of small and large companies, Gaske believes that MDU's smaller size might require a return more than 100 basis points higher than the proxy group. In addition, MDU faces the competition of propane and heating oil for new and existing load in its service territory. Furthermore, its rate structure recovers a substantial portion of its fixed costs in the volumetric component of its rates, and MDU does not have a weather normalization adjustment mechanism. On this basis, Gaske concluded that MDU's North Dakota gas distribution operations face somewhat greater overall business risks than the typical company in his proxy group.

59. King based his conclusion that MDU's gas distribution business is less risky than his comparison group on two facts. First, unlike eight of the 11 comparison companies, MDU's gas distribution operations have no non-regulated business activities. Second, MDU's equity ratio is higher than all but three of his comparison companies, suggesting a lower level of financial risk. He argued that a good case could be made for setting MDU's rate of return at the bottom of the scale of DCF returns for the comparison companies. However, in light of the possibility that the return set in this case may be in effect for an extended period into the future, he selected the midpoint between the lowest returns in his comparison group and the average.

60. In his rebuttal testimony, Gaske argued that King had failed to demonstrate any strong correlation between equity return and the equity proportion or the percent gas distribution revenues in his comparison companies. Gaske presented two correlation studies of these variables. One showed a weak, but measurable correlation between the percent equity in capital structure and King's estimates of DCF returns. The other showed no correlation between equity return and percent gas distribution revenues.

61. King conceded that neither of the two risk factors cited in his testimony are predictors of relative risk, but both are elements of relative risk. A high equity ratio is an indicator of low financial risk, and MDU's equity ratio is about equal to the highest of the equity ratios within his comparison group. The relationship between financial risk and capital structure, which King cites in this portion of his testimony, was also discussed in Gaske's initial testimony at some length.

62. King noted that another element of risk is the amount of non-regulated activity. Regulated activities are less risky than non-regulated activities. When regulated earnings are short, MDU can come to the Commission for an increase in rates. If the Commission grants the rate increase, there is no question whether MDU can collect the additional revenue because of its monopoly status. That is not true of non-regulated activities, which by definition do not have the security of revenue recovery.

63. King cited two further reasons that MDU gas distribution operations have lower risk than many of his comparison companies. Gas companies operating in warmer climates face competition from electric heating that MDU, operating in a cold climate, does not encounter. He testified that in Washington, DC, the Washington Gas Light Company has lost two-thirds to three-quarters of the commercial load to the electric company. For residential customers, heat pumps can combine heating with air

conditioning and so compete with gas. King stated that stand-alone heat pump units that do not draw heat from groundwater would not work in North Dakota's climate because they have to be supplemented with electric resistance heating when temperatures fall below about 45 degrees Fahrenheit.

64. The other difference cited by King relates to the intrusion of gas suppliers into the retail gas market. Some of his comparison companies (he cited Washington Gas and Atlanta Gas Light Company) are required to deliver the gas of independent suppliers. The extreme example is Atlanta Gas Light, which no longer buys gas on behalf of its customers. Instead, merchant gas suppliers buy the gas, and Atlanta Gas Light delivers it to end users on behalf of the suppliers. He testified that Atlanta Gas went from some 600,000 customers to 11. When one of these gas suppliers went bankrupt, Atlanta Gas was "stiffed" for several million dollars. In another example cited by King, Washington Gas has lost two thirds of its commercial load to competitive suppliers. The suppliers have failed to acquire the transportation capacity that Washington Gas had maintained to serve those lost customers, and there is now a risk that in a cold winter, the suppliers will not be able get the required gas to Washington.

65. King observed that MDU does not have the active competition from suppliers that larger companies serving larger service territories have. It therefore does not face the severe business risks associated with these suppliers.

66. King stated that Gaske conducted an apples-and-oranges comparison regarding the alleged risk of small company operations. Gaske has compared the risk properties and required returns of large companies with those of small, stand-alone companies. King says that is not the proper comparison. King states that the relevant objective in this case is to find the risk characteristics of the gas operations of a large company. Being part of a large company provides the security of greater financial strength and also diversification of financial resources. King states that MDU's North Dakota gas distribution operations are not a small, stand-alone company, as are the small companies from which Gaske derives his 100 basis point small-company risk adder. MDU's North Dakota gas distribution operations are merely one part of the overall business of MDU Resources Group. That company is well within the size range of the companies in both King's and Gaske's comparison groups.

67. King stated that while MDU's gas distribution operations are small, they have a lower financial risk than do most of King's comparison companies by reason of a high equity ratio. They have no risky, non-regulated activities, as do most of the comparison companies. While MDU faces competition from propane and oil, as do virtually all gas companies, it does not confront effective competition for its heating load from electricity, as do the comparison companies that operate in warmer climates. Finally, MDU does not have the intrusion of independent gas suppliers into its retail market in anything like the degree that some of the comparison companies have. For these reasons, King's concluded that MDU has somewhat less overall risk than his comparison companies.

68. The arguments about comparative risk are interesting and depict two fairly divergent views. We find some validity in both witnesses' arguments but not to the level of certainty that the Commission can choose one over the other. Accordingly, the Commission will not adjust its DCF findings to reflect the professional judgment of either of these witnesses regarding comparative risk between MDU and the eleven proxy companies.

Gaske's "Benchmark Analyses"

69. Gaske presented two types of "benchmark analyses." In one series, he added the historical differences between Treasury bonds and corporate bonds, on the one hand, and earnings from the common stock of small and, alternatively large companies, on the other. The other benchmark analysis was to identify the recent earned return on book value of S&P's 500 companies and on Value Line's industrial companies. The results of these benchmark analyses are as follows:

Risk Premium Return Based on:	
- U.S. Treasury Bonds	
v. Large Companies	13.3%
v. Small Companies	20.2%
- Corporate Bonds	
v. Large Companies	14.8%
v. Small Companies	22.2%
Alternative Investments	
- S&P 500	21.5%
- Value Line Industrials	29.4%

70. Gaske appears to conclude from these tests that his 13.5 percent cost of capital, derived from DCF results, is quite conservative relative to these benchmark results. King argued that these comparisons are irrelevant. King argued that these results should be disregarded, because their conceptual basis is fatally flawed and the risk premium observations are without value statistically.

71. Gaske's risk premium analysis purports to measure the required return to equity by adding the historical difference in experienced earnings from stocks and bonds to the current levels of bond yields. These historical differences, as measured by Ibbotson Associates, go back to 1926. The theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials.

72. King observed this theory is a statement of faith, not experience, and it defies logic. If investors' short-term expectations are continually being frustrated (as has been the case during the last year), what logic supports the proposition that the sum of those failed short-term expectations represents a valid long-term representation of their expectations? King further argued that it is untrue that the differential in required

returns between bonds and stocks is fixed and unchanging, as this theory postulates. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.

73. King stated that quite apart from this conceptual failing, the stock to bond comparison theory fails statistically. King referred to Exhibit 34 introduced by Gaske that shows annual returns to large company stocks, small company stocks and long-term corporate bonds, and it also shows their differences. King pointed out that the standard deviation of every one of these series is greater than the mean of the observations. King argued that the means therefore lack statistical significance and are useless as a predictive tool.

74. Gaske purports to demonstrate under his alternative equity investment analysis that MDU should be allowed a high return by observing that the returns to book equity on the S&P 500 companies from 1977 to 2000 have averaged 21.47 percent. He also observes that the book equity returns to 746 industrial, retail and transportation companies included in The Value Line Investment Survey have ranged from 27.57 percent to 31.75 percent over the five years 1996-2000. He argues that the average of 29.4 percent, along with the return of 21.47 percent experienced by S&P's 500 companies, suggests that the 13.25 percent he proposes for MDU is quite low.

75. King argued that these comparisons are irrelevant. He pointed out that investors in unregulated industrial, retail and transportation firms have no access to book equity value. The only value that is meaningful for investors in such firms is the market value. That is what an investor must pay to acquire the stock, and conversely, the value an investor will receive by selling the stock. Book equity value in an industrial firm is a purely historical number representing the dollars of original investment in equity capital contributed to (or retained by) the company. It has little relevance to the current market value, even for fairly capital-intensive firms. Since most stocks sell well above their book value, the return that is accessible to investors is considerably less than the 20 to 30 percent noted by Gaske.

76. King noted that book values are relevant for regulated utilities because regulation makes them so. Regulation sets the earnings allowance for such companies relative to a rate base reflective of the book value of the capital invested in utility operations. This condition does not apply to industrial firms.

King's Risk Premium Test

77. King did not attempt to find any absolute value of equity return using the risk premium approach. He agreed that equity investment, being inherently more risky than debt, requires a higher return. But rather than attempt the difficult (and arguably impossible) task of measuring that risk premium, he looked to the trends in bond yields in comparison to past North Dakota Commission findings of equity return to gas companies. King stated that if it appears that bond yields have increased, but he has

recommended a reduced return to equity, then there may be reason to question his finding. On the other hand, if his proposed equity return track with the changes in bond yields, then there is at least a "sanity check" on the propriety of his finding.

78. King identified three gas cases during the past 12 years in which the Commission had found a rate of return to equity. He compared those rates of return with the then-current yields on 10-year Treasury bonds and Aaa Corporate bonds. He then identified the current (that is, August 2002) bond yields. The results of his research are as follows:

Case	Utility	Date	ROE Allowed	10-Yr Treas.	Aaa Corporate
399-90-820	MDU	July 30, 1991	12.0%	8.27%	9.00%
400-95-559	NSP	June 7, 1996	12.0%	6.91%	7.71%
400-00-521	NSP	June 27, 2001	11.5%	5.28%	7.18%
399-02-183	**MDU**	August, 2002	**10.5%***	4.35%	6.45%

79. The Commission takes notice of the benchmark analyses prepared by Gaske and King. Again, these benchmark analyses or reasonableness tests are intended to bolster each witness's use of DCF and their own feelings about what is or isn't a fair return on MDU's natural gas investments. We take notice of the arguments for what they are but find no compelling reason to adjust the outcome of the basic DCF calculation. In light of current economic conditions within the United States, Gaske's benchmark returns using risk premium and alternative investments are so high that they are unreasonable. On the other hand, we find no reason to try and track Commission ordered returns on equity to interest on notes or bonds either. Therefore, given the above considerations and conclusions, we find that the current market expectations for a natural gas distribution company such as MDU is an opportunity to earn 11.329% on its common equity, as follows:

Proxy Company	Div. Est.	EPS Growth	Growth Factor	Div Growth	Next Yr Div.	50-day Price	Div. Yield	DCF Return
Atmos Energy	$ 1.18	6.43%	62.5%	4.02%	$ 1.23	$ 21.63	5.67%	12.105%
AGL Resources	$ 1.08	11.42%	62.5%	7.14%	$ 1.16	$ 21.76	5.32%	16.737%
Cascade Natural	$ 0.96	5.25%	62.5%	3.28%	$ 0.99	$ 19.69	5.04%	10.286%
LaClede Group	$ 1.34	4.25%	62.5%	2.66%	$ 1.38	$ 22.65	6.07%	10.323%
NICOR	$ 1.84	6.10%	62.5%	3.81%	$ 1.91	$ 35.06	5.45%	11.548%
Northwest Natural	$ 1.26	6.06%	62.5%	3.79%	$ 1.31	$ 28.28	4.62%	10.684%
People's Energy	$ 2.08	6.80%	62.5%	4.25%	$ 2.17	$ 34.00	6.38%	13.178%
Piedmont Natural	$ 1.60	4.67%	62.5%	2.92%	$ 1.65	$ 34.45	4.78%	9.450%
South Jersey Industries	$ 1.50	6.00%	62.5%	3.75%	$ 1.56	$ 32.85	4.74%	10.737%
Southwest Gas	$ 0.82	6.80%	62.5%	4.25%	$ 0.85	$ 22.79	3.75%	10.551%
WGL Holdings, Inc.	$ 1.27	3.65%	62.5%	2.28%	$ 1.30	$ 24.21	5.37%	9.015%
Average DCF Return								11.329%

Net Regulated Income

Revenues

80. Both MDU and staff agree on projected volumes for sales and transportation customers including the associated revenues and cost of gas. We find that the projections are reasonable and adopt them for purposes of determining just and reasonable rates.

Other O&M Expense: Bonuses and 2003 Labor Expenses

81. In its application, MDU projects labor cost increases of 3.15% and 3% for 2002 and 2003, respectively. MDU argued that the increases are smaller than the present labor market. Included in the projected labor cost increases is compensation for bonuses.

82. Staff witness Majoros proposed to eliminate bonuses from the forecasted test year and to hold test year labor costs to their 2002 levels. MDU included average bonuses for the years 1999-2001 in the amount of 6.1 percent of labor costs. Applied to the $8,239,000 in labor costs in 2002, the bonus elimination by staff comes to $503,000. The 2003 labor cost increase eliminated by Majoros amounts to $236,000. These direct labor cost adjustments reduce payroll taxes by $40,000 in 2002 and $60,000 in 2003.

83. Majoros testified that given the state of the economy and the fact that MDU is requesting a rate increase, it would be unreasonable to include bonuses or 2003 wage increases in the test year revenue requirement. Majoros accepted the 2002 labor cost increase, but objected to extrapolating that increase through 2003.

84. MDU witness, Richard D. Spratt, MDU's Vice President – Human Relations, argued that bonuses are an integral part of overall compensation philosophy to remain competitive with other employers. Part of that compensation is intentionally put at risk in the form of bonuses that are paid on the basis of various goals, including MDU's overall profitability. Spratt presented the results of an industry survey that showed most

utilities pay bonuses not only to management employees, but to salaried and hourly employees as well. Spratt stated that the elimination of bonuses would risk rendering MDU uncompetitive relative to other employers.

85. Staff witness Majoros argued that bonuses should not be built into rates because they are primarily paid out based on the profitability of the company. Spratt testified that two years ago, presumably in 2000, 75 percent of MDU's employees received a 7 percent bonus. Last year, 2001, their bonus was 0.6 percent. Presumably, these bonus levels reflect the fact that in 2000, MDU earned 11.96 percent on its North Dakota Gas Operations, but in 2001, it reported only 1.6 percent.

86. C. Wayne Fox, President of MDU Utilities Company, stated that from 1994 through 2001 the Consumer Price Index has risen nearly 20 percent, and in spite of that increase MDU has been able to hold-the-line on gas rates by finding ways of operating the business more efficiently and taking advantage of new technology. MDU even reduced its rates in 1999 through improved efficiency. Fox testified that MDU has reduced its employees by 30 percent since 1994. In that year there were 248 customers per MDU employee. In 2001, one employee was serving 370 customers. MDU witness, Rita Mulkern testified that while past employee reductions are reflected in the 2001 base period data, no further reductions are forecast for 2002 and 2003.

87. We find in favor of MDU. We believe the overall wage increases projected by MDU are fair and reasonable. The Commission believes that how those raises are distributed remains the responsibility of MDU's management and therefore will not delineate between the portion attributable to a general wage increase or bonuses. Further, we do not find the practice of paying bonuses based on profitability objectionable. In fact, the payment or lack of payment of bonuses depending on profitability smoothes out earnings and at the same time puts pressure on employees to perform. We do not accept the argument that because MDU has been able to reduce its workforce and beat inflation in recent years that it should be expected to do so forever more. Accordingly, the staff adjustment to Taxes Other Than Income to eliminate related payroll taxes is also denied.

Other O&M Expense: SISP

88. The Supplemental Income Security Plan ("SISP") is a plan that provides supplemental pension benefits to key employees. "Key employees" are officers, directors and senior managers of MDU Resources and MDU Utilities. The plan is expected to cost $259,000 in 2002 and $265,000 in test year 2003.

89. SISP was initiated in 1982, but MDU never sought its inclusion in rates until Case No. PU-399-01-186. The order states that staff characterized SISP as a double pension for a few key employees and that the plan lacked symmetry. Staff cautioned the Commission against such a plan given the Enron debacle and the payments it made to key employees. In its April 24, 2002 decision in that case, the Commission accepted Staff's position. The Commission concluded that it is inappropriate for ratepayers to bear the expense of the SISP costs.

90. MDU witness, Richard A. Espland, acknowledged that his testimony was essentially the same as it was in Case No. PU-399-01-186. Espland acknowledged that SISP benefits only MDU's high salaried employees with income ranges from a low of $75,000 to its president at around $250,000 to $300,000. Espland also agreed that none of the Public Utility Commission's in the jurisdictions where MDU provides natural gas utility services have approved a ratepayer funded SISP program. The Commission took administrative notice of its Findings of Fact, Conclusions of Law and Order in Case No. PU-399-01-186.

91. We find that the inclusion of an extra pension for key employees is still inappropriate and unnecessary as a ratemaking expense. We determined that SISP was inappropriate in Case No. PU-399-01-186 and none of the arguments have changed. Accordingly, we find no reason to order differently in this case. MDU's projected expense of $265,000 for SISP costs is denied.

Other O&M Expense: Rate Case Expense

92. MDU proposes to amortize $168,000 in rate case expenses over three years at $56,000 per year. Staff witness Majoros proposes to amortize the same amount over five years at $34,000 per year, for a difference in annual cost recognition of $22,000. Mulkern suggested that if the five-year amortization is adopted, the unamortized balance should be included as a rate base addition.

93. The basis of Majoros' proposal is the historical period between rate cases. Fox stated in his direct testimony that MDU's last rate increase, in Case No. PU-399-94-297, was decided in 1994, and a rate reduction occurred in 1999 in Case No. PU-399-96-325. This represents two rate cases in eight years, or one every four years. MDU has rounded down to three, and Staff has rounded up to five.

94. We find that the recent trends of a case every four years argues for an amortization period of four years. Accordingly, the Commission finds that ratemaking expense is $42,000 per year or a reduction to the company's projection of $14,000.

Other O&M Expense: General Inflation Adjustment

95. In 2001, MDU incurred $89,780,000 in operating and maintenance expense, of which $76,842,000 represented the cost of acquiring gas. Of the remaining $12,938,000 O&M cost relating to distribution, MDU developed specific forecasts for $9,249,000 based on projected changes for various categories of costs, e.g. labor, benefits, insurance, advertising. The remaining catchall category of $3,689,000 is projected to increase 2.8 percent annually at the assumed rate of general inflation.

96. Majoros noted that the Commission had never previously allowed this sort of inflation-based adjustment; that some sort of incentive to generate efficiency should remain and that some of the catchall provision includes fixed costs that are not subject to inflation.

97. MDU argued through its witness, Ms. Mulkern that these types of expenses are subject to inflationary pressures and that past Commission decisions rejecting this adjustment are no excuse for ignoring inflation in this proceeding.

98. We reject the idea that we have ignored inflation in the past or that we would in this proceeding. Instead, MDU has recommended that the Commission give it consideration for a number of specific adjustments that go beyond the 2.8% inflation factor and then add on 2.8% for any remaining and unadjusted expense levels. According to Statement N, Page 1 of MDU's application, the company has requested an overall increase in Other O&M expenses of more than 5% per year for its projected 2003 test year in comparison to 2001 actual expenses. Finally, the Commission order in this proceeding grants an increase in Other O&M expenses that exceeds the general inflation factor of 2.8% which is not necessarily indicative of changes in natural gas distribution costs.

99. MDU's proposal to increase "other" O&M costs at the rate of inflation through 2003 is rejected. The elimination of this adjustment reduces test-year expenses by $209,000.

Depreciation

100. Staff asserted that test year depreciation expense should be reduced by $2,172,000. MDU's current depreciation expense is based on rates developed in a 1991 study performed by Stone & Webster. Staff witness Michael J. Majoros performed a series of studies that suggested MDU's depreciation rates are excessive. First, he found that annual depreciation accruals during the past five years have exceeded utility construction and acquisition by $28.5 million. When common plant construction and acquisition is added, the five-year accruals still exceeded expenditures by $409,000. While it is not the purpose of depreciation to fund construction, this comparison indicates that MDU has obtained substantial cash flow from depreciation. Majoros noted that in *Lindheimer v. Illinios Bell Telephone Company,* 292 U.S. 151 (1934), the Supreme Court found that excessive depreciation results in the extraction of capital from ratepayers.

101. Majoros next observed that as of the end of 2001, the ratio of depreciation reserve to the original cost of distribution plant is 70.7 percent. Based on his experience, he testified that this level of depreciation reserve is extraordinarily high and suggests that prior depreciation rates have been excessive. Majoros stated that the likely source of these excessive rates is the 140 percent negative salvage adjustment for Account 380 – Services.

102. Majoros adjusted MDU's salvage factors based on an inconsistency between the net salvage assumed in the Stone and Webster study and actual net salvage that MDU has experience during the past five years. The Stone & Webster study developed depreciation rates that resulted in a large recovery of "negative salvage," that is, cost of removal. Specifically, its depreciation rates were designed to recover total gas plant of $102.5 million plus negative salvage (removal) costs of $46.9 million.

103. Majoros testified that MDU's actual net salvage experience has been positive. In every year since 1997, he testified that MDU has received more in salvage value for its retired gas and common plant than it has paid in removal cost. The total cumulative 5-year net positive salvage receipts for gas plant have amounted to $1,444,452. For common plant, net positive salvage receipts have come to $5,529,260.

104. To correct for over-recovery of net salvage, Majoros proposed to adopt the Stone & Webster lives and survivor curves for each account with no net salvage overlay. The account-by-account depreciation rates would thus represent pure depreciation, that is, solely the recovery of original cost. To recognize net salvage, Majoros proposed to deduct from total annual depreciation the average annual amount of net positive salvage for gas plant, plus the net positive salvage of common plant distributed between gas and electric operations based on their respective net salvage amounts. Under Majoros' proposal, total depreciation of test year plant would be $1,937,000. The annualized positive salvage offset would be $848,000, for a net test-year depreciation expense of $1,089,000.

105. Majoros noted that, in addition to matching net salvage accruals with actual net salvage experience, his treatment of removal costs conforms to Generally Accepted Accounting Principles ("GAAP") as recently defined in Statement of Financial Accounting Standards No. 143 ("FAS 143"). That standard, which MDU must adopt this year, requires companies to determine whether they have a legal obligation to retire property and incur the cost of removal or dismantlement. If they do, they must declare the present value of the future "asset retirement obligation" costs as a liability on their books to be amortized over the remaining life of the asset. If they do not, then the American Institute of Certified Public Accounts' Statement of Position on Property, Plant and Equipment would require that these costs be expensed as they are incurred.

106. Majoros testified that MDU has not determined whether it has asset retirement obligations, or what the present value of those obligations might be. For this reason, Majoros' adjustment reflects net salvage experience as a rolling five-year average of actual net removal costs.

107. In rebuttal, MDU witness John A. Jeter, a retired accountant from Arthur Anderson & Co. argued that Majoros had not done a depreciation study, that his review of the current depreciation rates is superficial and contains many errors, and that he has no basis for proposing changes in depreciation rates. According to Jeter, the current depreciation rates are based on a comprehensive study prepared in 1991 and used beginning 1994. He argued that no adjustment of depreciation rates should be entertained until the current depreciation study underway is completed and an appropriate review has taken place.

108. Jeter asserted that the 1991 depreciation study by Stone & Webster is a much more reliable source of information regarding net salvage than a cursory look at net salvage for all accounts over a five year period. Jeter did not explain the reason, nor

did he refute Majoros' observation that the Stone & Webster study had recommended large negative salvage allowances, while MDU's actual net salvage experience has been positive in recent years.

109. Jeter disagreed with Majoros' net salvage proposal to adjust overall depreciation by $848,000 based on the past five years' actual experience. He observed that the net salvage amounts used by Majoros varied from year to year and reflected the sale of an office building for approximately $4.6 million. Jeter further contended that Majoros allocated common property net salvage based on the direct net salvage amounts of the gas and electric operations, which is not the basis used by MDU. Jeter failed however to mention how MDU does allocate these common net salvage amounts or whether the difference in methods is material.

110. MDU asked the Commission to defer any consideration of depreciation until its new depreciation study, currently being conducted by AUS Consulting, is completed by the end of this year.

111. We find it unfortunate that the depreciation study currently underway could not be completed prior to the hearing. MDU has agreed to submit the new depreciation study for review by January 31, 2003 as a continued issue in this proceeding, subject to the standard and customary contested case process with all parties having rights of discovery, testimony, rebuttal testimony, hearing and briefing. MDU's depreciation filing will include gas and common plant facilities. Any resulting change in depreciation expense ordered by the Commission at the conclusion of the review will be reflected in rates on a prospective basis.

112. The Commission anticipates that this review should take no longer than six months from the date MDU files its new depreciation study. In the interim the Commission will allow MDU to implement rates reflecting the findings and conclusions in the instant order together with MDU's current depreciation rates. The Commission recognizes that the instant decision is a final decision as to all issues except for the depreciation issue, which is continued pending the filing and review of a new study. MDU's recently filed letter reflects MDU's agreement with this understanding.

113. Staff's adjustment reducing depreciation expense by $2.172 million is rejected.

114. From the foregoing, the Commission finds that MDU's projected Net Operating Income for 2003 is as follows:

Description	MDU	Adjustments	Commission
Sales	$ 67,962	$ -	$ 67,962
Transportation	900	-	900
Other	287	-	287
Total Revenues	$ 69,149	$ -	$ 69,149
Cost of Gas	$ 50,072	$ -	$ 50,072
Other O & M Expense	14,354	(488)	13,866
Total O & M Expense	$ 64,426	$ (488)	$ 63,938
Depreciation	3,261	-	3,261
Taxes Other Than Income	1,352	-	1,352
Current Income Tax Expense	(1,961)	192	(1,769)
Deferred Income Taxes	1,612	-	1,612
Total Expenses	$ 68,690	$ (296)	$ 68,394
Net Regulated Income	$ 459	$ 296	$ 755
Income Tax Calculation:			
NOI before Income Taxes	$ 110		$ 598
Interest Deduction:			
Rate Base	$ 19,681		$ 19,681
Weighted Cost of Debt	3.951%		3.969%
Interest Expense	$ 778		$ 781
Other Deductions	$ 4,282		$ 4,282
Taxable Income	$ (4,950)		$ (4,465)
Tax Rate	39.61%		39.61%
Income Tax Expense	$ (1,961)		$ (1,769)

115. From the foregoing, the Commission calculates that MDU's additional revenue requirement for the opportunity to earn 11.329% on common equity invested in North Dakota in 2003 is:

Change in Revenue Calculation	
Rate Base	$ 19,681
Weighted Cost of Capital	9.883%
Required Return	$ 1,945
Return Earned	$ 755
Difference	$ (1,191)
Tax Factor	1.656
Required Change in Revenue	$ (1,972)
Rate Increase Required	2.9%

Sale of Corporate Building

116. In this proceeding, it came to the attention of the Commission that MDU transferred the ownership of its Schuchart Building from the utility business to a non-regulated subsidiary. According to MDU's witness Keller, the building was transferred to recognize that less and less of the corporate business is related to the utility operations. The building was transferred at net book value without the benefit of a fair market value assessment. It appears that some after-the-fact analysis has been done to suggest the transfer was fair to ratepayers. The Commission wishes to remind MDU, as it would all public utilities, that the utmost care must be taken in completing such transactions. At a time in our history when corporate activities are being heavily scrutinized, it is imperative that MDU conduct business in an open and transparent manner, such that there is not even the slightest hint of corporate greed or chicanery.

Cost Allocation and Rate Design

Class Cost of Services Study

117. A class cost of service study is an analysis of the embedded or incremental costs of providing utility services to the customers or classes of customers that either cause these costs, or to whom these costs can reasonably be allocated. The purpose of performing a class cost of service study is to provide an indication of what it costs to provide utility service to each customer class and what rate of return each class provides. In prior rate applications the Commission has not adopted any particular study but has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers.

118. MDU Witness Tammie Aberle sponsored an embedded cost of service study for the year ended December 31, 2001. This study allocated all of MDU's recorded distribution, general and gas-related common plant among seven categories of customers:

- Residential
- Firm General
- Air Force
- Small Interruptible Sales
- Small Interruptible Transport
- Large Interruptible

119. The costs allocated to the respective customer classes were in turn subdivided into three categories:

- Capacity related costs vary with the amount of gas send out on the peak days of the year. Examples include the sizing of distribution mains and meters to account for the maximum volume of gas handled on any one day.
- Throughput related costs vary with the total amount of gas distributed throughout the year. Uncollectible accounts are an example of this type of cost.

- Customer related costs vary with the number of customers. Examples include the cost of meters, services and billing.

120. The only disagreement relating to this cost of service study concerned the allocation of the cost of mains. Mains constitute 39.1 percent of MDU's gas distribution plant, but their relevance exceeds even this percentage. That is because general and common plant, which account for another 20 percent of total plant, are allocated as overheads to the direct investment, of which mains are the largest component.

121. In its initial cost of service study, Statement M of Exhibit 2, MDU allocated mains 64 percent on the basis of peak two-day throughput during the year and 36 percent on the basis of the number of customers.

122. King objected to the allocation of a portion of mains costs on a customer count basis. The arguable justification for doing so is that the purpose of the mains system is to reach customers, and that when more customers are added, the mains system has to be extended. King argued that this is true only at the very edges of the system, where gas mains are being extended to serve new developments. Even then, the added cost of mains for new customers can vary dramatically depending on the location of those customers.

123. King testified that another purpose of mains is to deliver gas. He argued that the value derived and the benefits received from the mains system are more related to the amount of gas delivered than to the number of customers. One customer receiving twice as much gas as another customer enjoys exactly twice the BTU heating content. The two cannot be equated in terms of benefit received, yet that is what a customer allocation of mains does. He illustrated his point by using the example of a section of main that changes the number and makeup of customers over a period of several years, but the amount of gas delivered remains the same. The weighting of that main in the cost of service study would change under a customer allocation, but it would remain the same (although shifted among customer classes) if the allocation were made on the basis of annual throughput.

124. King therefore asked that MDU conduct an alternative study to allocate half the mains cost according to the classes' two-day peak throughput and half on the basis of annual throughput.

125. On rebuttal, Aberle objected to King's revisions, arguing that main additions are not made only on the edges of the system to provide new service to developments, but are also required to enhance system integrity and maintain pressure throughout the system as customer additions are made. She objected that heating content has no impact on the cost of the mains system. She also objected to the use of a peak-day allocator that assigns costs to the interruptible class and a throughput allocator that assigns costs to the transmission customers. She argued that both of these allocations violate practices previously approved by the Commission. She submitted yet a third

cost of service study, one, which allocates mains, based 50 percent on throughput at the distribution level and 50 percent on peak day use by firm customers.

126. The results of the three costs of service studies show the rate of return from each customer class as follows:

	MDU Statement M	King CWK-7	Aberle TAA-4
Residential	3.083%	7.731%	6.367%
Firm General	3.998%	2.161%	1.106%
Air Force	50.281%	3.502%	69.369%
Small Interruptible Sales	83.992%	38.040%	40.905%
Small Interruptible Transport	169.437%	48.490%	57.738%
Large Interruptible	78.644%	-0.673%	27.320%
Total North Dakota	6.439%	6.442%	6.442%

127. As noted earlier, the Commission has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers. We appreciate the information provided by each of the studies because it quantifies the impact that a change in allocation factor has on the rates of return from customer classes. The studies also show that, regardless of the allocator used to allocate mains to customer classes, some customer classes are providing a much higher return on MDU's investment to serve than are other customer classes. All three studies indicate the small interruptible classes generate a much higher than average rate of return while two of the studies indicate the same is true for the air force and large interruptible classes. The third study proposed by King indicates lower rates of return from the Air Force and large interruptible classes, but we are concerned that this study may not adequately recognize the value of controlling system peaks with interruptible load.

Rate Design

128. In its initial application, MDU made a number of rate design proposals, as follows:

- Increase residential and firm general service rates by 4.6 percent, reduce the small interruptible class rates by 4.1 percent, and leave the Air Force and large interruptible rates unchanged;
- Separate the commodity rate into a Distribution Delivery Charge and a Cost of Gas charge, eliminating the Purchased Gas Cost Adjustment;
- Eliminate the declining block rate form from the commodity charges and substitute a flat per-dekatherm ("dk") rate;
- Change the customer, or "Basic Service Charge" from a monthly to a daily charge;
- Increase the Basic Service Charges by very large percentages, for example, the residential charge increases from $6.50 to $11.70, the small firm service charge from $8.50 to $24.00 and the large firm service charge from $17.00 to $51.00.

- Eliminate the residential seasonal rate;
- Increase the penalty for failure of interruptible customers to interrupt from $10 to $50 per dk;
- Increase the return check fee to $20;
- Increase the reconnection fees for seasonal customers to match the avoided Basic Service Charges;
- Increase the reconnection charge for disconnected customers for nonpayment to $30;
- Modify the Firm Gas Extension Policy Rate 120 and 124 to reflect MDU ownership of all prospective service lines.

129. King recommended that the Commission accept a number of these proposals regardless of whether MDU's overall revenue is increased, decreased, or remains unchanged. The Commission finds the following consensus proposals should be approved:

- The commodity rate should be separated into two clearly distinct rates, the Distribution Delivery Charge and the Cost of Gas Rate.
- The declining block rates should be eliminated, and the revenue collected through the higher initial block rates should be reallocated to the Basic Service Charge.
- The residential seasonal rates should be eliminated, since there are no customers on these rates.
- Penalties for failure to interrupt should be increased, since MDU believes the current penalties are not sufficient to ensure interruptible customers respond to their calls for interruption or curtailment.
- The reconnection charges for seasonal customers should be adjusted to match the higher Basic Service Charges resulting from the elimination of declining commodity blocks.
- MDU's proposed modifications to the line extension policy should be adopted.

130. King recommended that the Commission reject MDU's proposal to increase the reconnection charge for discontinued service to $30. While MDU claimed that this is a cost-based rate, King suggested that there is a legitimate public policy reason for not increasing this rate. The customers to whom this charge applies are almost certainly the lowest income customers. Otherwise, they would not have been disconnected. Since they have to pay their arrearages anyway, they are likely suffering some difficulty getting reconnected. To impose on them yet more cost, such as an increase in the reconnection fee, might prevent some of these customers from obtaining vital utility service. MDU did not respond to King's recommendation. We agree with the policy considerations asserted by King and find MDU's proposal to increase the reconnection charge for disconnected customers should be denied.

131. MDU proposed to increase the returned check charge to $20 to reflect the current going rate charged by banks and other businesses when a check is returned for non-payment. However, MDU did not present any studies or other specific information to indicate its actual cost of returned checks. We find that returned check charges

should be based on cost and absent a showing by MDU that the proposed new rate is based on cost, MDU's proposal should be denied.

Rate Allocation Among Customer Classes

132. MDU proposed that residential and firm general service customers receive a rate increase of 4.6 percent, that the Air Force and large interruptible customers receive no increase, and that the small interruptible class receives a reduction of 4.1 percent. In the past the Commission has not approved rate reductions to some classes when granting an overall increase. Consistent with past Commission practice, we will not authorize any decrease for the small interruptible class. If a class receives a decrease when other classes receive an increase, the amount of the increase to the other classes will be higher. Revenue lost from giving one class a decrease must be made up by the other classes, thus increasing their burden.

133 The Commission finds the overall results of the class cost of service studies indicate that rates of return from the residential and firm general service classes are significantly less than those from the other classes. We share the desire to move towards more equalized rates of return between customer classes. The relatively small amount of revenue increase being granted in this case provides an opportunity to increase the rates of return from the firm general and residential classes without unduly burdening customers. Therefore, we will allow MDU to assign approximately equal percentage revenue increases reflecting the overall increase authorized to the residential and firm general service customer classes and approximately zero percentage increases to the other customer classes.

Monthly Customer Charges

134. King supported MDU's proposal to eliminate declining block commodity rates on the grounds that this rate structure implicitly encourages customers to use more gas, and it thereby discourages conservation. To the extent that it collects fixed customer costs in the commodity rate, it misstates the cause of the costs. Declining block rates also allow customers who use minor amounts of gas to escape the cost of providing the basic elements of service to them. As stated above, we agree with King that the declining block rate should be eliminated to more closely reflect cost causation in rates to customers.

135. Using MDU's billing unit counts for the year 2001, King calculated the revenue-neutral increase in monthly customer charges that would result if the present declining block rate structure were eliminated from each rate schedule. Under King's revenue neutral proposal, the resulting monthly customer charges would be as follows:

	Current	**Rev. Neutral**
Small Residential	$6.50	$8.43
Large Residential	$13.00	$15.31
Small Firm Service	$8.50	$14.34
Large Firm Service	$17.00	$45.16

135. King also recommended that the Commission consider MDU's proposal to convert the customer charges from monthly to daily charges. The proposal simplifies the calculation of the charge when customers are taking gas for only part of a month. We agree and find that MDU's monthly customer charge should be converted to a daily customer charge as proposed.

136. King had misgivings about MDU's proposal to increase customer charges dramatically, even for the classes for which it was proposing rate reductions or no rate increases. MDU witness Russell Feingold contended that shifting revenue recovery from the commodity to the customer component allows MDU to recover much more of its fixed costs on a non-weather sensitive basis. He asserted that this shift also protects customers from the volatility in their gas bills caused by variations in weather.

137. King was concerned with the issue of rate continuity. The sort of changes proposed by MDU would result in dramatically different bills for different types of customers. Very low-use customers might find higher percentage increases in their average monthly bills. Customers accustomed to low gas bills in the summer, that possibly offset high electric bills, could be surprised by the increase in their summer gas invoices.

138. King was further concerned that customers may resent high monthly customer charges. When most of the cost of gas is based on the level of gas consumption, customers can avoid high gas bills by conserving gas. But no amount of conservation permits a customer to avoid a monthly customer charge. As long as this charge is not a major portion of the bill, it is likely to be acceptable to most customers. But if it looms as a major element in the cost of gas service, customers will come to regard it as a tax from which there is no escape.

139. King recommended that customer charges should not be increased by more than twice any overall percentage increase. This would be in addition to the increases in customer charges that result from the flattening of the declining block rates. King testified if rates are reduced, the reductions should be flowed entirely into the commodity component of each rate schedule. King asserts that customer charges should not be increased when rates are reduced, except to eliminate the declining block feature of the rate schedules.

140. The Commission agrees that customer charge increases should be limited and will adopt King's recommendation for residential and small firm general service customers because customer charges are a more significant portion of their bill. We find the remaining monthly customer charges proposed by MDU should be approved. The resulting customer charges are:

	Current Monthly	Proposed Monthly	Proposed Daily	Authorized Monthly	Authorized Daily [1]
Residential Service		$ 11.70	$ 0.39	$ 8.91	$ 0.29
Small Meters	$ 6.50				
Large Meters	$ 13.00				
Firm General Service					
Small Meters	$ 8.50	$ 24.00	$ 0.80	$ 15.16	$ 0.50
Large Meters	$ 17.00	$ 51.00	$ 1.70	$ 51.00	$ 1.70
Air Force					
Firm	$ 35.00	$ 135.00		$ 135.00	
Interruptible	$750.00	$1,000.00		$1,000.00	
Small Interruptible					
Sales	$ 35.00	$ 100.00		$ 100.00	
Transport [2]	$ 35.00	$ 150.00		$ 150.00	
Large Interruptible					
Sales	$450.00	$ 675.00		$ 675.00	
Transport [2]	$450.00	$ 725.00		$ 725.00	

Notes:

1. Daily = Monthly X 12 / 365.25
2. Customer charge authorized for transportation service includes roll-in of $50 nominating fee currently charged separately under existing tariff.

Distribution Delivery Stabilization Mechanism

141. MDU proposes that if the Commission disapproves of MDU's increases in customer charges, it should adopt a Distribution Delivery Stabilization Mechanism ("DDSM") as an alternative. As described by Feingold, the DDSM would modify the effects of weather variations by adjusting bills for the difference between the actual heating degree-days and heating degree-days under normal weather. Following a cold winter, the excess in each class's revenue from the greater number of heating degree days would be divided by the projected annual sales volumes in that class and credited to all customers over the following year on a per-dk basis. Similarly, the revenue shortfall from a warmer than normal winter would be collected through a surcharge in the following year.

149. King testified that the value of a weather normalization adjustment should be to ameliorate the volatility in customer bills caused by variations in weather, and particularly the effect of unusually cold winters. In such winters, ratepayers typically experience a "double whammy." First, they consume more gas than usual, which increases their bills even if the price of gas remains the same. Then, because cold winters are usually a widespread phenomenon, the demand for gas is higher across the continent, which means that the price of gas is higher. The result is a further inflation in

their bills. Just this sort of inflation occurred across the country during the winter of 2000-2001.

150. King suggested that MDU's proposal could result in a "triple whammy." If North Dakota experiences an unusually warm winter, and it is followed by an unusually cold winter, ratepayers during the cold winter, already hard-hit, would find themselves paying a surcharge to make up for the shortfall in revenue collections in the previous year. The effect of MDU's program could be to increase, not decrease the volatility in customers' bills from year to year.

151. The Commission finds that MDU's alternative proposal should be denied, primarily because of its delayed effect. For a weather normalization adjustment to be beneficial to ratepayers and not just the utility, it must affect their bills when the unusual weather is occurring, not after it has occurred.

From the foregoing Findings of Fact, the Commission makes its:

Conclusions of Law

1. The Commission has jurisdiction over the parties and the subject matter of this proceeding.

2. MDU is entitled to rates and charges necessary to provide it an opportunity to earn a reasonable rate of return on its North Dakota natural gas property, used and useful, for the service and convenience of the public in North Dakota.

3. The rates authorized by the Commission herein will provide MDU with the opportunity to earn a reasonable rate of return on its property used and useful for the service and convenience of the public in North Dakota.

4. The depreciation issue in this proceeding is continued for the purpose of filing and review of, and decision on, a new depreciation study.

5. This order constitutes a final determination of all issues in this proceeding except the depreciation issue.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

Order

The Commission orders:

1. MDU may implement a rate increase for service rendered on and after December 12, 2002, sufficient to produce a total annual revenue increase of $1.972 million.

2. MDU shall file revised tariff sheets for Commission approval consistent with the foregoing findings of fact and conclusions of law.

3. MDU shall file its new depreciation study as soon as possible, but no later than January 31, 2003.

PUBLIC SERVICE COMMISSION

Anthony T. Clark	**Susan E. Wefald**	**Leo M. Reinbold**
Commissioner	**President**	**Commissioner**

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

CONCURRING OPINION
Commissioner Susan E. Wefald

December 18, 2002

I concur with all of the findings of facts and conclusions on law in this case except for finding 87. The Commission should not include bonus money for MDU employees as an element of a rate case.

If company profitability drives bonuses, as it appears to, then it is altogether inappropriate to include bonuses in a revenue requirement that drives a rate increase. As staff stated in its brief, "The reason MDU needs the rate increase is that it is not profitable. If it becomes profitable as result of a rate increase, that profitability will not have come about because the employees have performed particularly well. To the contrary, it will be because the employees have not performed well, and MDU needs rescue from the Commission. The revenue requirement imposed on ratepayers should not include rewards for poor performance. For this reason, bonuses should be disallowed." (page 14, Public Service Commission Staff Brief, filed November 15, 2002)

The overall wage increases projected by MDU are fair and reasonable. However, eliminating $503,000, which is equal to 6.1 percent of total approved labor costs in 2002 of $8,239,000, is prudent. This would reduce the amount of pay increase needed in 2003 by $236,000 (see finding 82). If the amount of the bonuses was eliminated, MDU would still have the ability to allocate any warranted bonus money with the remainder of the money in labor cost increases and the elimination would provide an incentive for company employees to find further cost savings and increase profitability.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **17th day of December, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with first class postage, fully prepaid, securely sealed and each containing a photocopy of:

Staff Response to Compliance Filing

The envelope were addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

William Pearce
P O Box 400
Bismarck ND 58502-0400

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sandra Scott

Subscribed and sworn to before me
this **17th day of December, 2002**.

Charlene A. Magstadt
Notary Public

SEAL

CHARLENE A. MAGSTADT
Notary Public, State of NORTH DAKOTA
My Commission Expires Jan. 7, 2004

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Affidavit of Service

by Public Service Commission

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NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

STAFF RESPONSE TO COMPLIANCE FILING

December 17, 2002

On December 16, 2002, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) filed tariff changes to comply with the Order of the Commission dated December 10, 2002. The Commission's Order required MDU to implement a rate increase sufficient to provide a total annual revenue increase of $1,972,000 effective for service on and after December 12, 2002.

MDU's compliance tariffs provide a total annual revenue increase of $1,975,600. The increase is spread over residential and firm general gas bills and sales volumes and results in a 3.08% increase for those customer classes. The commodity rate has been separated into two clearly distinct rates, the Distribution Delivery Charge and the Cost of Gas charge. The Cost of Gas charge is recalculated for the month of December 2002. The declining block rate elements have been eliminated. The residential seasonal rate has been eliminated. Penalties for failure to interrupt have been increased from $10 per dk of gas used in excess of the curtail amount to $50 per dk. The reconnection charges for seasonal customers has been adjusted to match the higher Basic Service Charges. The new line extension policy has been included. Customer charges have been adjusted in accordance with the Commission's order.

As directed by the Commission's Order, MDU did not change the reconnection charge for discontinued service and did not change the returned check charge.

Staff believes that MDU's compliance filing satisfies the Commission's Order.

Dated December 17, 2002

William W. Binek
Chief Counsel

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Staff Response to Compliance Filing
by Public Service Commission
12/17/2002 CC: Comm Legal Illona, Pat, Jerry Mike

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

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DEC 16 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

December 16, 2002

Executive Secretary
North Dakota Public Service Commission
State Capitol
Bismarck, ND 58505-0480

Re: Case No. PU-399-02-183
Compliance Tariffs - Addendum

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits an original and seven copies of the following tariff sheets:

- 2nd Revised Sheet No. 3.1, Rate Summary Sheet, to replace the 2nd Revised Sheet No. 3.1 filed on December 13, 2002 which contained a typographical error. As referenced in Rate 100, the Reconnection charge applicable to customers disconnected for nonpayment should be stated as $12.00.
- 1st Revised Sheet No. 7.1, Rate 64. The volume number has been revised to reflect the correct Volume No. 7.
- 1st Revised Sheet No. 30, Purchased Gas Cost Adjustment Rate 88 has been revised to remove the language at the end of Paragraph 3(a) referencing hedging program gains, losses & transaction costs. As noted in the current tariff, the authority to include such costs expired on March 1, 1999, and the intent was to exclude this language from Rate 88 in this Case.

Pursuant to a request from Mr. Patrick Fahn, a schedule showing the return on storage balances and prepaid demand and commodity balances is included. This schedule is in support of the purchased gas cost adjustment included in the compliance workpapers.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
DEC 18 2002
CASE NO. PU-399-02-183

Sincerely,

Donald R. Ball

Donald R. Ball
Directory of Regulatory Affairs

102 PU-399-02-183 Pages: 5
Compliance Tariffs Addendum
by Montana-Dakota Utilities Co., a Division of MDU Re
12/16/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
2nd Revised Sheet No. 3.1
Canceling 1st Revised Sheet No. 3.1

RATE SUMMARY SHEET

Miscellaneous Charges	Amount
Late Payment	1% per month
Returned Check	$10.00 per check
Reconnection charge after termination for nonpayment -During normal business hours -After normal business hours	 $12.00 Current service labor rate per hour
Reconnection charge after termination for causes defined in Rate 100 ¶19 -During normal business hours -After normal business hours	 $30.00 Current service labor rate per hour
Reconnection charge applicable to seasonal or temporary customers -During normal business hours -After normal business hours	Basic Service Charge applicable during the period while service was not being used. Minimum- $30.00 Minimum- Current service labor rate per hour
Reconnection charge applicable to transportation customers when remote data acquisition equipment must be reinstalled	$160.00

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
DEC 18 2002
CASE NO. PU-399-02-183

Date Filed: December 16, 2002
Effective Date: Service rendered on and after December 12, 2002
Issued By: Donald R. Ball
Directory of Regulatory Affairs
Case No.: PU-399-02-183

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 7.1
Canceling Original Sheet No. 7.1

AIR FORCE Rate 64

General Terms and Conditions:

1. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If the customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm Service distribution delivery charge and cost of gas rates set forth above, plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

2. CONTRACT – Terms of service other than the rate shall be specified in contracts between Minot Air Force Base, and PAR and the Company.

3. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
DEC 18 2002
CASE NO. PU-399-02-183

Date Filed:	December 16, 2002	**Effective Date:**	Service rendered on and after December 12, 2002
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Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 30
Canceling Original Sheet No. 30

PURCHASED GAS COST ADJUSTMENT Rate 88

1. **Applicability:**
This rate schedule constitutes a purchased gas cost adjustment (PGA) provision and specifies the procedure to be utilized to adjust the rates for gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of gas supply, (b) amortization of the Unrecovered Purchased Gas Cost Account and (c) market based pricing differential.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the PGA shall be bills rendered on and after the first date of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file a PGA to reflect changes in its average cost of gas supply only when the amount of change in such PGA is at least 10 (ten) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. **Purchased Gas Cost:**
(a) The monthly PGA shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent PGA. The cost of gas supply shall be the sum of all costs incurred in obtaining gas for general system supply. General system supply is defined as gas available for use by all customers served under retail sales rate schedules. The cost of gas supply shall include, but not be limited to, all demand, commodity, storage, gathering, and transportation charges incurred by Montana-Dakota for such gas supply, the overall rate of return on prepaid demand and commodity charges and gas storage balances required to maintain the system gas supply.

(b) The PGA shall be computed as follows:

(1) Demand costs shall include all annual gathering, transportation and storage demand charges at current rates.

(2) Commodity costs shall include all annual gathering, transportation and storage charges at current rates.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
DEC 18 2002
CASE NO PU-399-02-183

Date Filed:	December 16, 2002	**Effective Date:**	Service rendered on and after December 12, 2002
Issued By:	Donald R. Ball Director of Regulatory Affairs	**Case No.:**	PU-399-02-183

MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2002	$12,507,612	$593,920	$3,357,675
November	11,718,813	450,322	2,736,402
December	2,831,876	204,955	1,247,074
January 2003	(964,807)	(77,060)	(582,663)
February	(3,354,018)	(268,857)	(1,658,457)
March	(4,638,336)	(392,904)	(2,329,978)
April	(4,402,051)	(414,949)	(2,098,864)
May	(2,332,663)	(321,652)	(1,227,776)
June	362,443	(187,181)	(39,973)
July	3,305,957	(38,849)	1,199,326
August	6,215,502	107,413	2,414,409
September	8,491,266	738,571	3,380,407
October	8,804,168	724,680	3,693,942
13 month average	$2,965,059	$86,031	$776,271
Rate of Return	9.883%	9.883%	9.883%
Return	$293,037	$8,502	$76,719
Return Requirement - Revenue	$485,241	$14,078	$127,039

1/ Monthly balance from SENDOUT Model, allocated to North Dakota on ratio of storage capacity MDDQ.
2/ Monthly balance allocated to North Dakota on sales volumes.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
DEC 18 2002
CASE NO. PU-399-02-183

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

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DEC 13 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

December 13, 2002

Executive Secretary
North Dakota Public Service Commission
State Capitol
Bismarck, ND 58505-0480

Re: Case No. PU-399-02-183
Compliance Tariffs

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits an original and seven copies of revised tariff sheets relative to its natural gas operations in the state of North Dakota in compliance with the Commission's Order issued on December 10, 2002.

The rates set forth on the revised tariff sheets will produce additional annual revenues of $1,975,600, which is somewhat more than the authorized increase of $1,972,000 due to rounding in the rate design calculations. The revised tariffs reflect the following provisions as set forth in the Commission's Order:

Residential - An increase of 3.08% has been allocated to the Residential class which represents the overall increase as a percentage of the residential and firm general service revenues. The basic service charge for all residential customers has been set at $0.29 per day ($8.91 per month). The resulting distribution delivery charge is $.669 per dk in order to collect the total revenues allocated to the Residential class.

Firm General Service - An increase of 3.08% has been allocated to the Firm General Service class, which represents the overall increase as a percentage of the residential and firm general service revenues. The basic service charge for general service customers with meters rated less than 500 cubic feet per hour has been set at $0.50 per day ($15.16 per month) and the basic service charge for general service customers with meters rated greater than 500 cubic feet per hour has been set at $1.70 per day ($51.00 per month). The resulting distribution delivery charge is $.498 per dk in order to collect the total revenues allocated to the Firm General Service class.

Air Force - The basic service charge for the Minot Air Force Base reflects a monthly charge of $1,000.00 per month and the Perimeter Acquisition Radar (PAR) Site basic service charge has been set at $135.00 per

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Letter re compliance tariff filing
by Montana-Dakota Utilities Co., a Division of MDU R
12/16/2002 CC: Comm Legal Illona, Pat, Jerry Mike

month. The commodity charge has been correspondingly decreased to result in no change in total revenues to be collected from this class.

Small Interruptible - A basic service charge has been set at $100.00 per month for interruptible sales customers and $150.00 per month for interruptible transportation customers. The commodity charge has been correspondingly decreased to result in no change in total revenues to be collected from this class.

Large Interruptible - A basic service charge has been set at $675.00 per month for interruptible sales customers and $725.00 per month for interruptible transportation customers. The commodity charge has been correspondingly decreased to result in no change in total revenues to be collected from this class.

The other tariff changes, as originally proposed by Montana-Dakota, are included on the attached tariffs with the exception of the following:

- The reconnection charge for customers that have been disconnected for reasons of nonpayment has been left at the current charge of $12.00.
- The NSF check charge remains at the current charge of $10.00.
- The Distribution Delivery Stabilization Mechanism will not be implemented.

A complete set of the workpapers showing the development of the new rates is also attached hereto.

Montana-Dakota will implement the rates on December 18, 2002 to be effective with service rendered on and after December 12, 2002 upon final approval in accordance with the Commission's Order issued on December 10, 2002.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto.

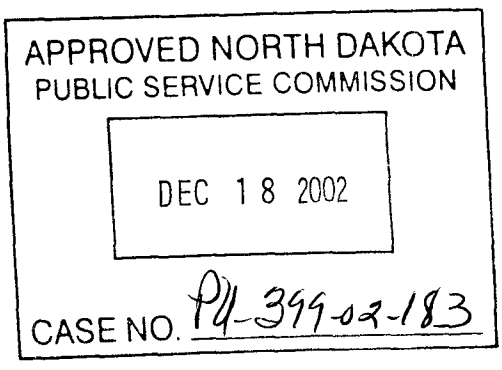
Sincerely,

Donald R. Ball

Donald R. Ball
Directory of Regulatory Affairs

MONTANA-DAKOTA UTILITIES CO.
CASE NO. PU-399-02-183
COMPLIANCE FILING

In the Matter of the Application of
Montana-Dakota Utilities Co. for
Authority to Establish Increased Rates
For Natural Gas Service in the
State of North Dakota



Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

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Original Sheet No. 1

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Director of Regulatory Affairs

Case No.: 100 PU-399-02-183

Compliance Tariff filing

by Montana-Dakota Utilities Co., a Division of MDU R

12/13/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

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COMMUNITIES SERVED

NATURAL GAS SERVICE

Dakota Heartland Region

Apple Valley	Devils Lake	Mandan	Steele
Barlow	Eldridge	Max	Surrey
Berthold	Fort Totten	Medina	Tappen
Bismarck*	Garrison	Minot	Turtle Lake
Burlington	Glen Ullin	New Rockford	Underwood
Carrington	Grafton	New Salem	Valley City
Cavalier	Jamestown	Park River	Walhalla
Cleveland	Langdon	Riverdale	Washburn
Dawson	Lincoln	Sandborn	Wilton
Des Lacs	Linton	Sheyenne	

Badlands Region

Alexander	Golva	Ray	Taylor
Arnegard	Hebron	Regent	Tioga
Beach	Killdeer	Rhame	Trenton
Belfield	Lefor	Richardton	Watford City
Bowman	Lignite	Ross	Wheelock
Dickinson*	Marmarth	Sentinel Butte	White Earth
East Fairview	Mott	Springbrook	Williston
Epping	New England	South Heart	
Gladstone	Palermo	Stanley	

PROPANE SERVICE

Badlands Region

Hettinger

*Designates Region Office

APPROVED NORTH DAKOTA
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A Division of MDU Resources Group, Inc.
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RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	PGA Items	Total Rate/ Dk
Residential Rate 60	4	$0.29 per day	$0.669	$3.558	$4.227
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$3.558	$3.696
Interruptible Service			$0.120	$2.448	$2.568
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.50 per day			
Meters rated > 500 cubic feet		$1.70 per day	$0.498	$3.558	$4.056
Small Interruptible Gas Rate 71	14	$100.00 per month	Per Contract	$1.974	Per Contract
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		$0.50 per day			
Meters rated > 500 cubic feet		$1.70 per day			
Winter Gas Usage			$0.498	$3.659	$4.157
Summer Gas Usage			$0.498	$2.536	$3.034
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.014	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.014	
Large Interruptible Gas Rate 85	27	$675.00 per month	Per Contract	$1.974	Per Contract
Residential Propane Rate 90	32	$0.29 per day	$0.669	$5.583	$6.252
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		$0.50 per day			
Meters rated > 500 cubic feet		$1.70 per day	$0.498	$5.583	$6.081

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Canceling Original Sheet No. 4

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.29 per day
Distribution Delivery Charge:	$.669 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

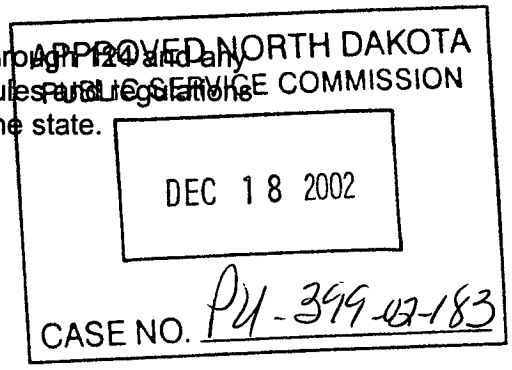
Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.



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AIR FORCE Rate 64

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate:

Basic Service Charge:

Minot Air Force Base	$1,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$135.00 per month

Distribution Delivery Charge:

Firm Service	$.138 per dk
Interruptible Service	$.120 per dk

Cost of Gas: Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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1st Revised Sheet No. 13
Canceling Original Sheet No. 13

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

Basic Service Charge:

For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.498 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$100.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$1.213 per dk	$.427 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the cost of Purchased Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

General Terms and Conditions:

1. PRIORITY OF SERVICE – Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

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SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS – Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS –Remote data acquisition equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder.

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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Gas Rate Schedule

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Canceling Original Sheet No. 15

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.498 per dk
Cost of Gas:	
Winter- Bills rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Bills rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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PUBLIC SERVICE COMMISSION
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Montana-Dakota Utilities Co.
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OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

General Terms and Conditions:

1. The customer agrees to contract for service under the Optional Seasonal General Gas Service Rate 72 for a minimum of one year.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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TRANSPORTATION SERVICE Rates 81 and 82

Availability:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through Company's distribution facilities. In order to obtain transportation service, customer must qualify under an applicable gas transportation service rate; meet the general terms and conditions of service provided hereunder; and enter into a gas transportation agreement upon request by the Company.

The transportation services are as follows:

Small Interruptible General Gas Transportation Service Rate 81:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point, whose average use of natural gas will not exceed 100,000 dk annually and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Small Interruptible General Gas Service Rate 71. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

Large Interruptible General Gas Transportation Service Rate 82:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually metered at a single delivery point, and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Large Interruptible General Gas Service Rate 85. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

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TRANSPORTATION SERVICE Rates 81 and 82

Rate:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:
Rate 81 $150.00 per month
Rate 82 $725.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$0.427	$0.298
Minimum Rate per dk	$0.102	$0.061
Balancing Charge per dk	$0.300	$0.300

Fuel Charge:
Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See Rate Summary Sheet t for currently effective charge.

General Terms and Conditions:

1. CRITERIA FOR SERVICE: In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

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TRANSPORTATION SERVICE Rates 81 and 82

2. REQUEST FOR GAS TRANSPORTATION SERVICE:
   a. To qualify for gas transportation service a customer must request the service pursuant to the provisions set forth herein. The service shall be provided only to the extent that the Company's existing operating capacity permits.

   b. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.10.

3. MULTIPLE SERVICES THROUGH ONE METER:
   a. In the event customer desires firm sales service in addition to gas transportation service, customer shall request such firm volume requirements, and upon approval by Company, such firm volume requirements shall be set forth in a firm service agreement. For billing purposes, the level of volumes so specified or the actual volume used, whichever is lower shall be billed at Rate 70. Volumes delivered in excess of such firm volumes shall be billed at the applicable gas transportation rate. Customer has the option to install at their expense, piping necessary for separate measurement of sales and transportation volumes.

   b. The customer shall pay, in addition to charges specified in the applicable gas transportation rate schedule, charges under all other applicable rate schedules for any service in addition to that provided herein (irrespective of whether the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE – Company shall have the right to curtail or interrupt deliveries without being required to give previous notice of intention to curtail or interrupt, whenever, in its judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

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TRANSPORTATION SERVICE Rates 81 and 82

5. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken above that received on customer's behalf, shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

6. NON-DELIVERED VOLUMES/PENALTY:
   a. In the event customer uses more gas than is being delivered to the Company's interconnection with the delivering pipeline(s) (receipt point), customer shall pay an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the same receipt point, any payment or overrun penalties the Company is required to make shall be allocated on a pro rata basis among such customers on the basis of each customer's use of gas in excess of available volumes.

   b. In the event the customer's gas is not being delivered to the receipt point for any reason and the customer continues to take gas, the customer shall be subject to any applicable penalties or charges set forth in Paragraph 6.a. Gas volumes supplied by Company will be charged at Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas). The Company is under no obligation to notify customer of non-delivered volumes.

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c. In the event customer's transportation volumes are not available for any reason, customer may take interruptible sales service if such service is available. The availability of interruptible sales service shall be determined at the sole discretion of the Company.

7. ELECTION OF SERVICE – Prior to the initiation of service hereunder, the customer shall make an election of its requirements under each applicable rate schedule for the entire term of service. If mutually agreed to by Company and customer, the term of service may be amended. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under the appropriate sales rate schedule for the customer's operations.

   Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge as specified in Rate 100, §V.17.

8. BALANCING:
   a. To the extent practicable, customer and Company agree to the daily balancing of volumes of gas received and delivered on a thermal basis. Such balancing is subject to the customer's request and the Company's discretion to vary scheduled receipts and deliveries within existing Company operating limitations.

      If, at the end of a billing month, the accumulated difference between actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer exceeds 4% of that month's scheduled receipts, resulting in a negative imbalance (i.e., deliveries exceed scheduled receipts), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, the customer shall then be billed, in addition to the applicable transportation rate,

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a penalty for the under nominated volume exceeding 4% at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas). The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume on which a penalty was imposed.

If, at the end of a billing month, the accumulated difference between nominated (scheduled) receipts on behalf of such customer and actual gas deliveries to the customer exceeds 4% of that month's scheduled receipts resulting in a positive imbalance (i.e., scheduled receipts exceed deliveries), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, (1) the Company may adjust the volume of gas received on behalf of the customer so as to eliminate the prior period over nomination exceeding 4% up to 10% and (2) the Company shall retain the over nomination of gas exceeding 10% free and clear of any adverse claims relating thereto when such accumulated difference exceeds 50 dk. The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume retained.

b. In the event customer's imbalance causes the Company to incur a balancing penalty from its interconnecting pipeline(s), customer shall pay any penalty payments or overrun charges the Company is required to make under the terms of its contract(s) with interconnecting pipeline(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the

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same interconnection with a delivering pipeline, any payment or overrun penalties the Company is required to make shall be apportioned among such customers on the basis of each customer's contribution toward the imbalance.

c. Customer's nomination made to clear imbalances will be subject to the priority of service and allocation of capacity provisions set forth in Rate 100, §V.10 and the penalties for failure to curtail or interrupt use of gas set forth in Paragraph 5 of this rate schedule.

d. Termination of the gas transportation service shall not relieve Company and customer of the obligation to correct any quantity imbalances hereunder or customer of the obligation to pay money due hereunder to Company.

e. The Company may waive any penalty associated with Company adjustments to end-use customer nominations in those instances where the Company, due to operating limitations, is required to adjust end-use transportation customer nominations and such Company adjustments create a penalty situation, or preclude a customer from correcting an imbalance which results in a penalty.

9. NOMINATION VARIANCE CHARGE – The customer shall pay any payments the Company must make to its interconnecting pipeline(s), as a result of nomination variance penalties caused by customer's nomination variances. Such penalties will be allocated on the basis of each customer's contribution toward the nomination variance.

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10. METERING REQUIREMENTS:
    a. Remote data acquisition equipment required by the Company for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by the customer. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. Company may remove such equipment when service hereunder is terminated.

    b. The customer shall provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

    c. The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

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11. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper or agent shall advise Company's gas nominations center, by 11:30 a.m. Central Clock Time, of the dk requirements customer has requested to be delivered at each delivery point the following day. Customer's daily nomination shall be its best estimate of the expected utilization for the gas day. Unless other arrangements are made, customer will be required to nominate for the non-business days involved prior to weekends and holidays.

    b. All nominations should include shipper and/or agent defined begin and end dates. Shippers and/or agents may nominate for periods longer than 1 day, provided the nomination begin and end dates are within the term of the service agreement.

    c. The Company has the sole right to refuse receipt of any volumes which exceed the maximum daily contract quantity and at no time shall the Company be required to accept quantities of gas for a customer in excess of the quantities of gas to be delivered to customer. If total nominated receipts exceed total deliveries at receipt points where more than one customer is receiving service, nominations will be allocated on a pro rata basis.

    d. At no time shall Company have the responsibility to deliver gas in excess of customer's nomination.

    e. In the event that more than one customer is receiving gas from the same shipper and/or agent at the same receipt point, any reduction in nominated volumes will be allocated on a pro rata basis, unless Company and shipper(s) and/or agent(s) have agreed to a predetermined allocation procedure.

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12. WARRANTY – The customer, customer's agent, or customer's shipper warrants that it will have title to all gas it tenders or causes to be tendered to the Company, and such gas shall be free and clear of all liens and adverse claims and the customer, customer's agent, or customer's shipper shall indemnify the Company against all damages, costs, and expenses of any nature whatsoever arising from every claim against said gas.

13. FACILITY EXTENSIONS - If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities required to furnish firm gas service, the customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. Company may remove such facilities when service hereunder is terminated.

14. PAYMENT – Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

15. BILLING ERROR – In the event an error is discovered in any bill that the Company renders to customer, such error shall be adjusted within a period not to exceed 6 months from the date the billing error is first discovered.

16. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for service hereunder.

17. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

This rate schedule shall not apply for service to U.S. Government installations, which are covered by separate special contracts.

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge	$675.00 per month	
Distribution Delivery Charge	Maximum $1.003 per dk	Minimum $.298 per dk
Cost of Gas	Determined Monthly- See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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General Terms and Conditions:

1. PRIORITY OF SERVICE – Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 90 days prior to the end of the initial term. Absent execution of such termination notice, the agreement shall continue for additional terms of equal length until written notice is given as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

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4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS –Remote data acquisition equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder.

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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(3) The gas commodity cost shall reflect all commodity related gas costs estimated to be in effect for the month the PGA will be in effect and annual dk requirements.

(4) The return on prepaid demand and commodity balances and storage balances shall be computed on an annual basis at the overall rate of return on rate base.

The cost per dk for the month is the sum of the above divided by annual, weather normalized dk deliveries adjusted to reflect losses.

(c) Monthly gas costs shall be calculated as follows:

(1) Demand costs for firm customers shall be apportioned to all state jurisdictions served by Montana-Dakota on the basis of the overall ratio of each state's Maximum Daily Delivery Quantity (MDDQ).

(2) Demand costs for interruptible sales customers shall be stated on a 100% load factor basis.

(3) All commodity costs and other costs associated with the acquisition of gas for general system supply shall be apportioned to each state on the basis of total dks sold in each state, regardless of the actual points of delivery of such gas.

(4) The return requirement related to prepaid demand and commodity charges and gas storage balances shall be included on a per dk basis. The prepaid demand and storage balances shall be apportioned to all states on the basis of each state's MDDQ. The prepaid commodity charges shall be apportioned to all states on the basis of annual dks sold in each state. The unit cost shall be calculated using a thirteen-month average balance and the currently authorized return on rate base.

(5) All costs related to specific end-use transactions shall not be included in the cost of gas supply determination but shall be directly billed to the customer(s) contracting for such service.

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(d) The PGA shall be applied to each of Montana-Dakota's rate schedules recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. Surcharge Adjustment:

(a) All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on May 1 of each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Gas Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

5. Unrecovered Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in a Purchased Gas Cost Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for gas supplies, which were paid during any period after the effective date of the most recent general rate case, but not yet included in sales rates.

(3) Refunds received from supplier(s) with respect to gas supply. Such refunds received shall be credited to the Unrecovered Purchased Gas Cost Account.

(4) Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

(5) Demand costs recovered from the interruptible sales customers will be credited to the residential and firm general service customers.

(b)

(1) The amount to be included in the Unrecovered Purchased Gas Cost Account in order to reflect the items specified in Subsections 5(a)(1), (2), and (3) shall be calculated as follows:

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(i) Montana-Dakota shall first determine each month the unit cost for that month's natural gas supply as adjusted to levelize demand charges.

Such adjustment to levelize supplier(s) demand charges shall be calculated as follows:

The supplier's annual (calendar or fiscal) demand charges, which are payable in equal monthly payments shall be accumulated in a prepaid account (FERC Account 165). Each month a portion of such accumulated prepaid amount shall be amortized to cost of natural gas purchased (FERC Account 804). Such monthly amortization shall be based on a rate calculated by dividing the annual supplier(s) demand charges by projected annual natural gas sales units (calendar or fiscal, as appropriate). The resulting product shall then be multiplied by the projected natural gas unit sales for the current month. Such amount shall constitute the monthly amortization of prepaid supplier(s) demand charges to cost of natural gas supply.

(ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for gas supply which is reflected in the currently effective PGA.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Gas Cost Account for each rate schedule.

(1) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Gas Cost Account, Account 191, at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The amount to be included in Account 191 for carrying charges shall be determined as follows:

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Each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge; which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Unrecovered Purchased Gas Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(b) Reduction of Amounts in the Unrecovered Purchased Gas Cost Account:

(1) The amounts in the Unrecovered Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Gas Cost Account specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Unrecovered Purchased Gas Cost Account specified in Subsection 5(a)(4).

6. Market-Based Pricing Differential:

(a) At the time of each surcharge adjustment, the Company will compute a credit to residential and firm general service rates based on 50% of all distribution delivery charge revenues received from small interruptible sales and large interruptible sales customers in excess of the authorized minimum distribution delivery charge rate approved in the most recent general rate case.

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(b) The unit adjustment shall be determined by dividing the balance resulting under Subsection 6(a) by the residential and firm general service sales volumes estimated to be sold during the 12 months following the effective date of each adjustment.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file each PGA at least 20 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised PGA sheets identifying the amounts of the adjustments and the resulting currently effective PGA rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant pipeline tariff sheets supporting costs claimed.

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1st Revised Sheet No. 32
Canceling Original Sheet No. 32

RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.29 per day
Distribution Delivery Charge:	$.669 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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1st Revised Sheet No. 34
Canceling Original Sheet No. 34

FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:

For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.498 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

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Issued By:	Donald R. Ball Director of Regulatory Affairs	**Case No.:**	PU-399-02-183

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Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
Original Sheet No. 34.1

FIRM GENERAL PROPANE SERVICE Rate 92

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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PUBLIC SERVICE COMMISSION
DEC 18 2002
CASE NO. PU-399-02-183

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PURCHASED PROPANE COST ADJUSTMENT Rate 99

1. **Availability:**
This rate schedule constitutes a purchased propane cost adjustment (PCA) provision and specifies the procedure to be utilized to adjust the rates for propane gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of propane supply and (b) amortization of the Unrecovered Purchased Propane Cost Account.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the PCA shall be bills rendered on and after the first day of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file a PCA to reflect changes in its average cost of propane supply only when the amount of such change in PCA is at least 10 (ten) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. **Purchased Propane Cost:**
(a) The monthly PCA shall reflect changes in Montana-Dakota's cost of propane supply as compared to the cost of propane supply approved in its most recent PCA . The cost of propane supply shall include, but not be limited to, all commodity and transportation charges incurred by Montana-Dakota for such propane supply.

(b) The propane commodity cost shall reflect all commodity related propane costs estimated to be incurred for the month the PCA will be in effect and estimated dk purchases.

The unit cost per dk for the month shall be the commodity costs divided by estimated dk purchases for the month.

4. **Surcharge Adjustment:**
All propane sales schedules shall be subject to a Surcharge Adjustment to be effective on May 1 each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Propane Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

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5. Unrecovered Purchased Propane Cost Account:

(a) Items to be included in the Unrecovered Purchased Propane Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for propane supply which Montana-Dakota is unable to reflect in a Purchased Propane Cost Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for propane supplies that were paid during any period after the effective date of the most recent approved rates, but not yet included in propane sales rates.

(3) Carrying charges or credits.

(b)

(1) The amount to be included in the Unrecovered Purchased Propane Cost Account in order to reflect the items specified in Subsections 5(a)(1) and (2) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's propane supply.

(ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for propane supply, which is reflected in the currently effective PCA.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each propane rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Propane Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Propane Cost Account, Account 191, as follows:

Each month, Account 191 shall be debited (on a debit balance) or credited (on a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

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(i) The balance on Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The carrying charges shall be accrued in a supplementary Unrecovered Purchased Propane Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in the Unrecovered Purchased Propane Cost Account:

(1) The amounts in the Unrecovered Purchased Propane Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Propane Cost Account specified in Subsections 5(a)(1) and (2) and the amounts in the supplementary Unrecovered Purchased Propane Cost Account specified in Subsection 5(b)(2)(ii).

6. Time and Manner of Filing:

(a) Montana-Dakota shall file each PCA at least 10 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised PCA sheets identifying the amounts of the adjustments and the resulting currently effective PCA rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant material supporting costs claimed.

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I. **PURPOSE:**

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Service Commission of North Dakota and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. **DEFINITIONS:**

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

AGENT – The party authorized by the transportation service customer to act on that customer's behalf.

APPLICANT – A customer requesting Company to provide service.

COMMISSION – Public Service Commission of the State of North Dakota.

COMPANY – Montana-Dakota Utilities Co.

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT – A reduction of transportation or retail natural gas service deemed necessary by the Company. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

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CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by Company at one location and at one point of delivery unless otherwise expressly in these rules or in a rate schedule.

DELIVERY POINT – The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on customer's premises.

GAS DAY – Means a period of twenty-four consecutive hours, beginning and ending at 9:00 a.m. Central Clock Time.

INTERRUPTION – A cessation of transportation or retail natural gas service deemed necessary by Company.

NOMINATION – The daily dk volume of natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

PIPELINE – The transmission company(s) delivering natural gas into company's system.

RATE – Shall mean and include every compensation, charge, fare, toll, rental and classification, or any of them, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT – The intertie between Company and the interconnecting pipeline(s) at which point Company assumes custody of the gas being transported.

SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.

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III. **CUSTOMER OBLIGATION:**

1. APPLICATION FOR SERVICE – A customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. The Company may refuse a customer or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses gas service in the absence of application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

   Any customer may be required to make a deposit as required.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at Company's sole discretion, Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will ensure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

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3. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

4. COMPANY PROPERTY – The customers shall exercise reasonable diligence in protecting the Company's property on their premises, and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

5. INTERFERENCE WITH COMPANY PROPERTY – The customer shall not disconnect, change connections, make connections or otherwise interfere with Company's meters or other property or permit same to be done by other than the Company's authorized employees.

6. RELOCATED LINES - Where Company facilities are located on a public or private utility easement and there is a building encroachment(s), over gas facilities (Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

7. NOTIFICATION OF LEAKS – The customer shall immediately notify the Company at its office of any escape of gas in or about the customer's premises.

8. TERMINATION OF SERVICE – All customers are required to notify the Company, to prevent their liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

9. REPORTING REQUIREMENTS – Customer shall furnish Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

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IV. **LIABILITY**

1. CONTINUITY OF SERVICE – The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

2. CUSTOMER'S EQUIPMENT – Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer or leased by the customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE – The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE – In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor

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shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorization from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

V. **GENERAL TERMS AND CONDITIONS:**

1. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for any service.

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2. RATE OPTIONS – Where more than one rate schedule is available for the same class of service, the Company will assist the customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in twelve months unless there is a material change in the customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

3. RULES FOR APPLICATION OF GAS SERVICE:
   (a) Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, may be served on the residential rate.

   (b) Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty parlors, master metered apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site (this is not an all-inclusive list).

   (c) The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

   (d) If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for

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(e) nonresidential purposes as defined herein), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by Company to facilitate transportation service. Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Homes Construction and Safety Standards) Subpart G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission rules.

   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (b) The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to

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the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided prompt payment record has been established.

7. METERING AND MEASUREMENT:
   (a) Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. Company will test meters in accordance with applicable state utility rules and regulations.

   (b) Transportation customers agree to provide the cost of the installation of remote data acquisition equipment to Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the

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application of a thermal factor to the volumes metered. This thermal factor consists of:

(a) An altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

(b) A Btu adjustment factor used to reflect the heating value of the gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT – The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and at a temperature base of sixty degrees Fahrenheit (60°F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AGA-3/NX-19, as amended, supercompressibility calculation. For handbilled accounts, application of supercompressibility factors will be waived on monthly-billed volumes of 250 dk or less.

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from Highest to Lowest:
    (a) Priority 1 – Firm sales services.
    (b) Priority 2 – Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
    (c) Priority 3 – Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.

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(d) Priority 4 – Small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
(e) Priority 5 – Large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
(f) Priority 6 – Gas scheduled to clear imbalances.

Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE – A charge of $10.00 will be collected by the Company for each check charged back to the Company by a bank.

13. TAX CLAUSE – In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any sales

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use or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

The charges to be added to the customer's service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

14. UTILITY CUSTOMER SERVICES:
(a) The following services will be performed at no charge regardless of the time of performance:

(1) Fire and explosions calls.

(2) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

(3) Maintenance or repair of Company-owned facilities on the customer's premises.

(b) The following service calls will be performed at no charge during the Company's normal business hours:

(1) Cut-ins and cut-outs.

(2) Disconnecting of gas appliances permanently removed from service or in connection with cut-outs.

(3) Lighting pilots, inspecting, and adjusting gas equipment in connection with establishing service when working cut-in orders.

(4) Initial burner adjustment on residential gas burning appliances.

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(5) High bills or inadequate service complaints.

(6) Location of underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

(7) Pilot relighting, testing thermocouple for proper operation and any pilot cleaning that can be done without removing pilot assembly.

(8) Service calls for routine cut-ins, when the order is received prior to 12:00 p.m. on a regular work day, requiring service on the date the order is received, will be considered as non-chargeable regardless if work is performed outside of normal working hours.

15. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and materials at retail prices.

    Customers requesting service after the Company's normal business hours will be informed of the after hour service rate and encouraged to have the service performed during normal business hours.

16. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service disconnected shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

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17. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER –A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged the Basic Service Charge applicable during the period while service was not being used or a minimum of $30.00. The minimum will be based on standard overtime rates for reconnection of service after normal business hours.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the required electronic measurement equipment is necessary.

18. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $12.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours.

19. DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS – The Company reserves the right to discontinue service for any of the following reasons:

    (a) In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    (b) In the event of tampering with the equipment furnished and owned by the Company.

    (c) For violation of or noncompliance with the Company's rules on file with the Commission.

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(d) For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

(e) For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying Company facilities.

The Company may collect a reconnect fee of $12.00 before restoring gas service, which has been disconnected for the above causes.

20. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with a Company meter, pressure regulator, registration, connections, equipment, seals, procedures or records that result in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.

(a) Examples of unauthorized use of service include the following, but are not limited to:

(1) Bypass piping around meter.
(2) Bypass piping installed in place of meter.

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(3) Meter reversed.
(4) Meter index disengaged or removed.
(5) Service or equipment tampered with or piping connected ahead of meter.
(6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
(7) Gas being used after service has been discontinued by the Company.
(8) Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

(b) In the Event that there has been unauthorized use of service, customer shall be charged for:

(1) Time, material and transportation costs used in investigation.
(2) Estimated charge for non-metered gas.
(3) On-premise time to correct situation.
(4) Any damage to Company property.

(c) Customer service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid all charges as hereinafter set forth in this procedure.

(1) All delinquent bills, if any.
(2) The amount of any Company revenue loss attributable to said tampering.
(3) Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in number 20.b above.
(4) Reconnection fee applicable.
(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

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GENERAL PROVISIONS Rate 100

21. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
    Rate 102 – Residential Rate for Regular Employees
    Rate 119 – Interruptible Gas Service Extension Policy
    Rate 120 – Firm Gas Service Extension Policy
    Rate 124 – Service Lines

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RESIDENTIAL GAS SERVICE FOR REGULAR EMPLOYEES
Rate 102

The bill for residential gas service for regular employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly owned subsidiaries of MDU Resources Group, Inc., shall be computed at the applicable rates and the amount reduced by 33-1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular employee who has been continuously employed at least six months and is the principal support of the household in which employee resides, or is the spouse of the principal support.

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INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide interruptible sales or interruptible transportation service to customers is as follows:

1. Contribution

   (a) Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, service line(s), regulators, meters (excluding remote data acquisition equipment), any required payments made by the Company to the transmission pipeline to accommodate the extensions, and other costs as adjusted for federal and state income taxes.

   (b) The contribution shall be made by:

      i. A one-time payment prior to construction or,

      ii. The customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the total contribution required prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for a five-year period commencing at the plant in service date, and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists for the subject project, the surety or guarantor shall pay the Company for such contribution requirement, or

      iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

   (c) Upon Completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied ~~or a refund may be~~ made.

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Rate 119

(d) Remote data acquisition equipment costs shall be subject to the terms and conditions specified in Transportation Service Rates 81 and 82.

2. Refund

(a) If within the five-year period from the extension(s) in service date, the total of the customer's contribution and actual margin paid to the Company equals or exceeds the total present value of the revenue requirement associated with the extension, Company shall refund the amount exceeding the revenue requirement on the following basis:

i. Annually, beginning at the 2nd anniversary of the extension(s) in service date, the Company will refund to the customer, the amount exceeding the total present value of the revenue requirement at a rate of 50% of the current year margin associated with the customer" actual throughput.

ii. Customers who have posted a bond, letter of credit, or a written guarantee commitment will be notified of any reduction in surety or guarantee requirements based on the above calculation.

iii. No refunds will be made for amounts less than $25.

(b) Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

(c) No refund shall be made by the Company after the five-year refund period has expired, and in no case shall the refund, excluding interest, exceed the amount of contribution made by the customer.

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FIRM GAS SERVICE EXTENSION POLICY Rate 120

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales service to customers is as follows:

(A) General Rules and Regulations Applicable to all Firm Service Extensions

1. An extension will be constructed without a contribution if the estimated capital expenditure is cost justified as defined in ¶A.3.

2. The Company may require customer or developer cost participation if the estimated capital expenditure is not cost justified.

3. The extension will be considered cost justified if the calculated maximum allowable investment equals or exceeds the estimated capital expenditure using the following formula:

   Maximum Allowable Investment =

   Annual Basic Service Charge + (Project Estimated 3rd Year Annual Dk x Distribution Delivery Charge)/LARR

   where: LARR = Levelized Annual Revenue Requirement Factor of 19.954%

4. Cost of the extension shall include the gas main extension(s), valves, service line(s), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs excluding the distribution meter and regulator.

   The service line is that portion of the gas service extending from the gas main to the connection at the house regulator and/or meter.

5. Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer or the developer and Company.

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6. A refund will be made only when there is a reduction in the amount of contribution required within a five-year period from the extension(s) in service date. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

   No refund shall be made by Company after the five-year refund period and in no case shall the refund excluding interest, exceed the amount of the contribution.

7. The Company reserves the right to charge customer the cost associated with providing service to customer if service is not initiated within 12 months of such installation.

(B) Customer Extensions

Cost participation for extensions where customers will be immediately available for service is as follows:

1. Contribution

   (a) When a contribution is required, the customer(s) shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with ¶ A.3.

   (b) The contribution shall be made by:

      i. A one-time payment prior to construction, or

      ii. Payment of 25% of the contribution prior to construction and the balance in no more than twenty-four equal monthly installments. If customer discontinues service within the twenty-four month period, the balance will be due and payable upon discontinuance of service, or

      iii. Customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized

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to do business in the state, letter of credit, or written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exits in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement, or

iv. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

(c) Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

(d) If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment.

(e) The recalculated contribution requirement shall be collected from the new applicant(s).

2. Refund

(a) The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Customers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

(b) No refunds will be made until the new applicants begin taking service from the Company.

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(c) If the addition of new customers will increase the contribution required from existing customer(s), the extension will be considered a new extension and treated separately.

3. Incremental Expansion Surcharge

(a) The Company, in its sole discretion, may offer an Incremental Expansion Surcharge (Surcharge) to a project consisting of 10 or more customers requesting service when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. If the Company and customers mutually agree that the project will be funded through a Surcharge, the project will be designated an expansion area and the Surcharge will be applicable to all connections within the expansion area. The contribution requirement to be collected under the Surcharge shall be the amount of the capital expenditure in excess of the Maximum Allowable Investment determined in accordance with ¶A.3.

i. A minimum up-front payment of $100.00 will be collected from each customer who signs an agreement to participate in the expansion.

ii. For projects that are expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus $1.50 per dk.

iii. For projects that are not expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus a commodity charge designed to provide recovery of the contribution requirement in a five-year period.

(b) The Surcharge shall remain in effect until the net present value of the contribution requirement, calculated using a discount rate equal to the overall rate of return authorized in the last rate case, is collected.

(c) The Surcharge shall apply to all customers connecting to natural gas service within the expansion area until the contribution requirement is satisfied.

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(d) The net present value of the Surcharge will be treated as a contribution-in-aid of construction for accounting purposes.

(C) Developer Extensions

Cost participation may be required for extensions such as a subdivision or a mobile home court, in which a developer is installing roads, utilizes, etc., before housing is built.

1. Contribution

(a) When a contribution is required, the developer shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with ¶A.3.

(b) The contribution shall be made by:

i. A one-time payment prior to construction, or

ii. Developer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or a written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the subject project based on a recalculated maximum expenditure, the surety shall reimburse the Company for such recalculated contribution requirement, or

iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

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(c) Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

2. Refund

(a) If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment. Such recalculation shall be done annually based upon the anniversary of the extension(s) in service date.

(b) The Company will refund to the developer the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Developers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guaranty requirements.

(c) If the addition of new customer(s) will increase the contribution required from the developer, the extension will be considered a new extension and treated separately.

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NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

1. The Company will install, at its expense, a service line extending from the main to the connection at the premise regulator and/or meter for all customers connected on and after (effective date of tariff) and all replacement service lines installed on and after (effective date of tariff). The service line installed by the Company will remain the Company's property.

2. A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation.

3. The portion of the service line not cost justified shall be charged to the customer on the basis of direct costs to the Company. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

4. Where service line location changes are made due to building encroachments (a building is being constructed or is already located over a service line, etc.), the customer shall be charged for on the basis of direct costs incurred by the Company.

5. Whenever a service line is damaged by the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

6. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with ¶2 above.

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RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.2939 per day
Distribution Delivery Charge:	$.669432 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.5080 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.498410 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

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A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 14
Canceling Original Sheet No. 14

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$100.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$1.213 per dk	$.427~~366~~ per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the cost of Purchased Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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Gas Rate Schedule

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Canceling Original Sheet No. 15

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.5080 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.498410 per dk
Cost of Gas:	
Winter- Bills rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Bills rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

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Gas Rate Schedule

TRANSPORTATION SERVICE Rates 81 and 82

Rate:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:
Rate 81 $150.00 per month
Rate 82 $725.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$0.427~~366~~	$0.298
Minimum Rate per dk	$0.102	$0.061
Balancing Charge per dk	$0.300	$0.300

Fuel Charge:
Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See Rate Summary Sheet t for currently effective charge.

General Terms and Conditions:

1. CRITERIA FOR SERVICE: In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

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State of North Dakota
Gas Rate Schedule

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Canceling Original Sheet No. 32

RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.2939 per day
Distribution Delivery Charge:	$.669432 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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State of North Dakota
Gas Rate Schedule

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Canceling Original Sheet No. 34

FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.5080 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.498410 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided prompt payment record has been established.

7. METERING AND MEASUREMENT:
   (a) Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. Company will test meters in accordance with applicable state utility rules and regulations.

   (b) Transportation customers agree to provide the cost of the installation of remote data acquisition ~~electronic measurement~~ equipment to Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the

(d) Priority 4 – Small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
(e) Priority 5 – Large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
(f) Priority 6 – Gas scheduled to clear imbalances.

Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE – A charge of $10.00~~20.00~~ will be collected by the Company for each check charged back to the Company by a bank.

13. TAX CLAUSE – In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any sales,

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State of North Dakota
Gas Rate Schedule

GENERAL PROVISIONS Rate 100

17. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER –A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged the Basic Service Charge applicable during the period while service was not being used or a minimum of $30.00. The minimum will be based on standard overtime rates for reconnection of service after normal business hours.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the required electronic measurement equipment is necessary.

18. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $12.00~~30.00~~ before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours.

19. DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS – The Company reserves the right to discontinue service for any of the following reasons:

    (a) In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    (b) In the event of tampering with the equipment furnished and owned by the Company.

    (c) For violation of or noncompliance with the Company's rules on file with the Commission.

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State of North Dakota
Gas Rate Schedule

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INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide interruptible sales or interruptible transportation service to customers is as follows:

1. Contribution

   (a) Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, service line(s), regulators, meters (excluding remote data acquisition ~~electronic measurement~~ equipment), any required payments made by the Company to the transmission pipeline to accommodate the extensions, and other costs as adjusted for federal and state income taxes.

   (b) The contribution shall be made by:

      i. A one-time payment prior to construction or,

      ii. The customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the total contribution required prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for a five-year period commencing at the plant in service date, and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists for the subject project, the surety or guarantor shall pay the Company for such contribution requirement, or

      iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

   (c) Upon Completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

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State of North Dakota
Gas Rate Schedule

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NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

1. The Company will install, at its expense, a service line extending from the main to the connection at the premise regulator and/or meter for all customers connected on and after (effective date of tariff) and all replacement service lines installed on and after (effective date of tariff). The service line installed by the Company will remain the Company's property.

2. A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation.

3. The portion of the service line not cost justified shall be charged to the customer on the basis of direct costs to the Company. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

4. Where service line location changes are made due to building encroachments (a building is being constructed or is already located over a service line, etc.), ~~because~~ the customer shall be charged for on the basis of direct costs incurred by the Company.

5. Whenever a service line is damaged by the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

6. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with ¶2 above.

MONTANA-DAKOTA UTILITIES Co.
GAS UTILITY - NORTH DAKOTA
ALLOCATION OF REVENUES
Projected 2003

	Billing Determinants					Embedded COS Before Increase		
RATE CLASS	Bills	Dk	Distribution Revenues	Gas Costs	Total Revenues	Operating Income	Rate Base	Rate Of Return
Residential	878,101	7,899,840	$11,896,536	$27,301,847	$39,198,383	$218,608	$11,903,347	1.84%
Firm General Service	135,039	5,609,220	5,404,766	19,374,560	24,779,326	169,342	7,127,004	2.38%
Air Force								
Firm	12	36,450	6,653	125,971	132,624			
Interruptible	24	1,014,790	135,254	2,312,840	2,448,094			
Total Air Force	36	1,051,240	141,907	2,438,811	2,580,718	46,430	155,001	29.95%
Small Interruptible								
Sales	852	489,700	279,268	1,123,864	1,403,132			
Transportation	860	1,030,440	557,408		557,408			
Total Small IT	1,712	1,520,140	836,676	1,123,864	1,960,540	236,416	315,925	74.83%
Large Interruptible								
Sales	0	0	0	0	0			
Transportation	108	2,246,820	342,735	0	342,735			
Total Large IT	108	2,246,820	342,735	0	342,735	84,204	179,723	46.85%
Total North Dakota	1,014,996	18,327,260	$18,622,620	$50,239,082	$68,861,702	$755,000	$19,681,000	3.84%

	Target Rate Design -Distribution Revenues				Rate Design Results			
RATE CLASS	Increase In Revenue	% Increase	Operating Income	Rate Of Return	Increase In Revenue	Total Revenues	% Incr	Rate Of Return
Residential	$1,208,221	3.08%	$948,253	7.97%	$1,212,336	$40,410,719	3.09%	7.99%
Firm General Service	763,779	3.08%	630,588	8.85%	762,650	25,541,976	3.08%	8.84%
Air Force								
Firm					(3)	132,621	0.00%	0.00%
Interruptible					141	2,448,235	0.01%	0.00%
Total Air Force	0	0.00%	46,430	29.95%	138	2,580,856	0.01%	30.01%
Small Interruptible								
Sales								
Transportation								
Total Small IT	0	0.00%	236,416	74.83%	615	1,961,155	0.03%	74.95%
Large Interruptible								
Sales								
Transportation								
Total Large IT	0	0.00%	84,204	46.85%	(139)	342,596	-0.04%	46.81%
Total North Dakota	$1,972,000	2.86%	$1,945,891	9.89%	$1,975,600	$70,837,302	2.87%	9.898%

INPUTS:

Requested Return on Rate Base	9.883%
Proposed Increase	$1,972,000
% Increase	2.86%
Inverse Of Tax Rate	60.39%
% Increase Res & FG Only	3.082324%

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA

Customer Class/Rate	Projected 2003 Bills	Projected 2003 Dk	Projected 2003 Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	878,101	7,899,840	$39,198,383	$40,410,719	$1,212,336	3.1%
Firm General Service - Rate 70	135,039	5,609,220	24,779,326	25,541,976	762,650	3.1%
Air Force - Rate 64						
Firm	12	36,450	132,624	132,621	(3)	0.0%
Interruptible	24	1,014,790	2,448,094	2,448,235	141	0.0%
Total Air Force	36	1,051,240	2,580,718	2,580,856	138	0.0%
Small Interruptible						
Sales - Rate 71	852	489,700	1,403,132			0.0%
Transport - Rate 81	860	1,030,440	557,408			0.0%
Total Small Interruptible	1,712	1,520,140	1,960,540	1,961,155	615	0.0%
Large Interruptible						
Sales - Rate 85	0	0	0			
Transport - Rate 82	108	2,246,820	342,735			
Total Large Interruptible	108	2,246,820	342,735	342,596	(139)	0.0%
Total North Dakota	1,014,996	18,327,260	$68,861,702	$70,837,302	$1,975,600	2.9%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE RECONCILIATION
RESIDENTIAL GAS SERVICE - RATE 60
Projected 2003

	BILLING UNITS	RATE	AMOUNT	TOTAL REVENUE
Residential Rate 60- Zone 1				Daily
Rate 600 Bills (< 500 meter)	696,239	$8.91	$6,203,489	$0.29
Rate 601 Bills (> 500 meter)	1,052	8.91	9,373	0.29
Total Bills	697,291		$6,212,862	
First 5 Dk	2,672,232	$0.669	1,787,723	
Over 5 Dk	3,598,318	$0.669	2,407,275	
	6,270,550		4,194,998	
Total Distribution Revenue Rates 60 - Zone 1			10,407,860	
Cost per Bill			$14.93	
Residential Rate 60- Zone 2				
Rate 602 & 900 Bills (< 500 meter)	180,690	$8.91	$1,609,948	
Rate 603 Bills (> 500 meter)	120	8.91	1,069	
Total Bills	180,810		$1,611,017	
First 5 Dk	691,863	$0.669	462,856	
Next 10 Dk	674,278	$0.669	451,092	
Over 15 Dk	263,149	$0.669	176,047	
	1,629,290		1,089,995	
Total Distribution Revenue Rates 602, 603 & 900			2,701,012	
Cost per Bill			$14.94	
Total Revenues Per Design				13,108,872
Target Distribution Revenues				13,104,757
Difference				$4,115

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RESIDENTIAL GAS SERVICE - RATE 60
Projected 2003

Current Non-Gas Revenues	$11,896,536
Proposed Revenue Increase	1,208,221
Total Revenue Requirement	$13,104,757
Less:	
Base Rate Revenues	7,823,879
1st Block Differential Revenues	0
Zone 2 Differential Revenues	0
Remaining Revenues To Be Collected	5,280,878
Total Rates 60 & 90 (Res) Consumption	7,899,840
Base Distribution Charge	$0.669
Blocking Differentials	
Zone 1 First Block	$0.000
Zone 2 First Block	$0.000
Zone 2 Second Block	$0.000

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
AIR FORCE FIRM SERVICE - RATE 64
Projected 2003

CLASS	BILLING UNITS	RATE	AMOUNT	TOTAL REVENUE
Bills (PAR Site)	12	$135.00	$1,620	
Dk (PAR Site)	36,450	$0.138	5030	
Total Revenue			$6,650	

Total Revenues Per Design	$6,650
Target Revenues	6,653
Difference	($3)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
PROPOSED RATE DESIGN
AIR FORCE FIRM SERVICE - RATE 64
Projected 2003

Air Force Firm Revenue Requirement	$6,653
Proposed Revenue Increase	0
Total Revenue Requirement	$6,653
Less: Base Rate Revenues	1,620
Remaining Revenues To Be Collected	$5,033
Total Rate 64 Firm Consumption	36,450
Non-Gas Commodity Charge	$0.138

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE SERVICE - RATE 64
Projected 2003

CLASS	BILLING UNITS	RATE	AMOUNT	TOTAL REVENUE
Air Force Interruptible				
Bills				
Minot Air Force	12	$1,000.00	$12,000	
PAR Site	12	135.00	1,620	
Total Bills	24		13,620	
Dk				
Minot Air Force	894,630	$0.120	$107,356	
PAR Site	120,160	0.120	14,419	
Total Dk	1,014,790		$121,775	
Total Revenue			$135,395	
Total Revenues Per Design				$135,395
Target Revenue				135,254
Difference				$141

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
PROPOSED RATE DESIGN
AIR FORCE INTERRUPTIBLE SERVICE - RATE 64
Projected 2003

Air Force Interruptible Revenue Requirement	$135,254
Proposed Revenue Increase	0
Total Revenue Requirement	$135,254
Less: Base Rate Revenues	13,620
Remaining Revenues To Be Collected	$121,634
Total Rate 64 IT Consumption	1,014,790
Non-Gas Commodity Charge	$0.120

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE RECONCILIATION
FIRM GENERAL GAS SERVICE - RATE 70
Projected 2003

	BILLING UNITS	RATE	AMOUNT	TOTAL REVENUE
Firm General Rate 70- Zone 1				Daily
Rate 700, 720 & 725 Bills (< 500 meter)	71,777	$15.16	$1,088,139	$0.50
Rate 701, 721 & 726 Bills (> 500 meter)	27,697	51.00	1,412,547	1.70
Total Bills	99,474		$2,500,686	
First 15 Dk	938,457	$0.498	467,352	
Over 15 Dk	3,330,313	$0.498	1,658,496	
	4,268,770		2,125,848	
Total Distribution Revenue Rates 70 & 72- Zone 1			4,626,534	
Cost per Bill			$46.51	
Firm General Rate 70- Zone 2				
Rate 702, 722, 727 & 920 Bills (< 500 meter)	26,241	$15.16	$397,814	
Rate 703, 723, 728 & 921 Bills (> 500 meter)	9,324	51.00	475,524	
Total Bills	35,565		$873,338	
First 15 Dk	336,268	$0.498	167,461	
Over 15 Dk	1,004,182	$0.498	500,083	
	1,340,450		667,544	
Total Distribution Revenue Rates 70 & 72- Zone 2			1,540,882	

Total Revenues Per Design	6,167,416
Target Revenues	6,168,545
Difference	($1,129)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
FIRM GENERAL GAS SERVICE - RATE 70
Projected 2003

Pro Forma Revenues	$5,404,766
Proposed Revenue Increase	763,779
Total Revenue Requirement	$6,168,545
Less:	
Base Rate Revenues	3,374,024
Zone 1 First Block	0
Zone 2 First Block	0
Remaining Revenues To Be Collected	2,794,521
Total Rates 70, 72 and 90 (Firm) Consumption	5,609,220
Base Commodity Charge	$0.498
Blocking Differentials	
Zone 1 First Block	$0.000
Zone 2 First Block	$0.000

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
SMALL INTERRUPTIBLE - RATE 71
Projected 2003
Excluding Flexed Contracts

CLASS	BILLING UNITS	RATE	AMOUNT	TOTAL REVENUE
Small Interruptible - Zone 1				
Bills				
Rate 710 Sales	468	$100.00	$46,800	
Rate 81 Transport	576	150.00	86,400	
Total	1,044		133,200	
Nomination Charges	576	0.00	0	
Dk				
Sales	352,530	$0.427	150,530	
Transport	607,270	0.427	259,304	
Total	959,800		$409,834	
Total Revenue				$543,034
SMALL INTERR - ZONE 2				
Bills				
Rate 712 Sales	384	$100.00	$38,400	
Rate 81 Transport	264	150.00	39,600	
Total	648		78,000	
Nomination Charges	264	0.00	0	
Sales				
First 15 Dk	3,955	$0.427	$1,689	
Over 15 Dk	133,215	0.427	56,883	
Total Sales	137,170		$58,572	
Transport				
First 15 Dk	3,960	0.427	$1,691	
Over 15 Dk	242,910	0.427	103,723	
Total Transport	246,870		$105,414	
Total Revenue	384,040			$241,986
Total Small Interruptible Revenues				$785,020
Target Revenues				784,405
Difference				$615

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
PROPOSED RATE DESIGN
SMALL INTERRUPTIBLE SERVICE - RATE 71
Projected 2003
Excluding Flexed Contracts

Small Interruptible Revenue Requirement	$836,676
Less: Flexed Contracts	(52,271)
Proposed Revenue Increase	0
Proposed Revenue Requirement	784,405
Less:	
Base Rate Revenues & Nomination Charges	211,200
Zone 2 First Block	0
Remaining Revenues To Be Collected	$573,205
Total Throughput Rates 71 & 81 (Excluding Flexed Contracts)	1,343,840
Commodity Charge	$0.427
Blocking Differentials:	
Zone 2 First Block	$0.00

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
LARGE INTERRUPTIBLE SERVICE - RATE 82
Projected 2003

CLASS	BILLING UNITS	RATE	AMOUNT	TOTAL REVENUE
Bills	48	$725.00	$34,800	
Nomination Charges	48	$0.00	0	
Dk	475,620	$0.298	141,735	
Total Revenue			$176,535	

Total Rate 85 Revenue	$176,535
Target Revenue	176,674
Difference	($139)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
PROPOSED RATE DESIGN
LARGE INTERRUPTIBLE SERVICE - RATE 82
Projected 2003

Revenue Requirement- Excluding Flexed Contracts	$342,735
Less: Flexed Contracts	(166,061)
Proposed Revenue Increase	0
Total Revenue Requirement	$176,674
Less: Base Rate Revenues & Nomination Charges	34,800
Total Revenue Requirement	$141,874
Total Throughput Rates 82 & 85 (Excluding Flexed Contracts)	475,620
Commodity Charge	$0.298

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE DECEMBER 2002
COMPLIANCE FILING

	Amount
Total Gas Costs 1/	$55,878,221
Residential and General Service dk Requirements 2/	13,661,142
Average Cost of Gas per dk	$4.090
Average Cost of Gas as Adjusted for Losses @ 99.55%	$4.108
Less: Gas Cost Level in Base Tariff Rates 3/	$3.443
Cumulative Gas Cost Adjustment	$0.665

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 4 -11 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.
2/ Normalized dk sales for the twelve months ended September 30, 2002, adjusted for losses at .45%.
3/ Gas Cost Level in Base Tariff Rates:

Cost of Purchased Gas	$3.428
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.443

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE DECEMBER 2002
COMPLIANCE FILING

	Amount
Total Gas Costs 1/	$11,359,736
Interruptible Service dk Requirements	3,766,960
Average Cost of Gas per dk	$3.016
Average Cost of Gas as Adjusted for Losses @ 99.55%	$3.030
Less: Gas Cost Level in Base Tariff Rates 2/	$2.287
Cumulative Gas Cost Adjustment	$0.743

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 4 -11 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C, allocated to interruptible on MDDQ.

2/ Gas Cost Level in Base Tariff Rates:

Cost of Purchased Gas	$2.277
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$2.287

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE DECEMBER 2002
COMPLIANCE FILING

	Amount
Total Gas Costs 1/	$2,653,733
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$3.016
Less: Gas Cost Level in Base Tariff Rates 2/	$2.277
Cumulative Gas Cost Adjustment	$0.739

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 4 -11 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C, allocated to Air Force interruptible on MDDQ.

2/ Gas Cost Level in Base Tariff Rates:

Cost of Purchased Gas	$2.277

MONTANA-DAKOTA UTILITIES CO.
PCA TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE DECEMBER 2002
COMPLIANCE FILING

Propane Cost Adjustment:

Current Propane Cost Adjustment (Page 2)	$1.651

Surcharge Adjustment:

Current Adjustment	($0.455)
Total PCA	**$1.196**

Propane Cost Level in Base Rates	$4.387
Plus: Total PCA	$1.196
Total Propane Cost Level in Rates	$5.583

MONTANA-DAKOTA UTILITIES CO.
PURCHASED PROPANE COST ADJUSTMENT
NORTH DAKOTA
EFFECTIVE DECEMBER 2002
COMPLIANCE FILING

Cost of Purchased Propane	$47,666
Gallons Purchased	86,665
Projected dk Sales	7,930
Propane Cost per Dk	$6.011
Average Cost of Propane as Adjusted for Losses @ 99.55%	6.038
Less: Propane Cost Level in Base Tariff Rates 1/	4.387
Current Propane Cost Adjustment	$1.651

1/ Base cost of propane effective December 15, 1999 in Case No. PU-399-99-601.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **10th day of December, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Findings of Fact, Conclusion of Law, and Order

The envelope were addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 1940 0005 3425 2306

William Pearce
P O Box 400
Bismarck ND 58502-0400
Cert. No. 7001 1940 0005 3425 2313

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 1940 0005 3425 2276

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **10th day of December, 2002.**

Sandra L. Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

99 **PU-399-02-183** Pages: 5
Affidavit of Service
by Public Service Commission
12/10/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **10th day of December, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Findings of Fact, Conclusions of Law, and Order

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **10th day of December, 2002**.

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

Sandra L Scott
Notary Public

SEAL

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MOTION

December 10, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission adopt the Order in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application in Case No. PU-399-02-183.

sdh

98 **PU-399-02-183** Pages: 1

Motion

by Public Service Commission

12/10/2002 CC: Comm Legal Illona, Pat, Jerry Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

December 10, 2002

Appearances

Commissioners: Susan E. Wefald, Leo M. Reinbold, Anthony T. Clark.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy staff.

William P. Pearce, Attorney at Law, 314 E. Thayer Ave., PO Box 400, Bismarck, ND 58502-0400, appearing for Montana-Dakota Utilities Co.

Douglas W. Schulz, Senior Attorney, MDU Resources Group, Inc., PO Box 5650, Bismarck, ND 58506-5650, appearing for Montana-Dakota Utilities Co.

Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

On April 12, 2002, the North Dakota Public Service Commission received an application from Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) to increase its natural gas rates 4.1%. The requested increase in rates would generate an additional $2,844,132 annually in North Dakota. MDU's application is based on a calendar 2003 projected test year.

MDU stated that the primary reasons for its application are increased operation and maintenance costs, depreciation, and taxes other than income, and a higher required rate of return. MDU's requested return on rate base is 11.044 percent, including a return of 13.25 percent on common equity.

In its application, MDU also requested a significant restructuring of its rates, including a separation of gas distribution from gas supply charges, elimination of declining block commodity charges and increases in customer charges. Additionally, MDU proposed that all increases be flowed into the firm residential and commercial rate schedules, that no change in rate levels be applied to the Air Force and large interruptible schedules, and that the small interruptible class should receive a rate reduction.

On April 24, 2002, the Commission suspended MDU's rates filed with its application. On June 5, 2002, the Commission issued its Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline.

The Notice of Hearing specified the issues to be considered at the technical hearing, which are:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

The Notice of Hearing provided that any person wishing to intervene as a party in the proceeding must file a petition for intervention by September 9, 2002. No one petitioned to intervene as a party in the proceeding.

Public input sessions were held via video teleconference on July 15, 2002, in Bismarck, Dickinson, Williston, Minot, Devils Lake, and Jamestown. The technical hearing was held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota on October 7-8, 2002.

On December 6, 2002 MDU filed a letter indicating its understanding of and agreement with the continuation of the depreciation issue, as more fully set forth below.

The Commission, having reviewed the evidence in the record makes the following:

Findings of Fact

1. MDU is an investor owned utility company providing natural gas distribution service in North Dakota operating as a division of MDU Resources Group, Inc.

2. The parties do not dispute the following issues:

- 2003 test year for rate determination.
- Jurisdictional cost of service study.
- 2003 test year for rate base (except accumulated reserve for depreciation)
- Cost of preferred equity.
- Test year revenues.

3. The parties dispute the following issues:

- Cost of capital
- Depreciation
- Bonuses and labor expenses
- Supplemental Income Security Plan
- Rate case expense
- General inflation adjustment for expenses
- Other unadjusted operation and maintenance expenses
- Allocation of cost to customer classes
- Rate design (partially)
- Distribution Delivery Stabilization Mechanism

Test Year Rate Base

4. MDU and Staff are in agreement on the amount of rate base for the 2003 test year with the exception of accumulated reserve for depreciation. The staff adjustment to accumulated reserve for depreciation is affected by a staff adjustment to depreciation expense of $2,172,000. For reasons discussed later, the Commission does not accept staff's adjustment and finds that MDU's projected rate base for 2003 is reasonable.

5. The Commission finds the following 2003 test year rate base:

Rate Base	*(Thousands)* Balance
Plant in Service	$ 72,793
Accumulated Depreciation	49,356
Net Plant	$ 23,437
Materials and Supplies	439
Fuel Stocks	22
Prepayments	84
Other	44
Accumulated Deferred Taxes	(3,842)
Accumulated ITC's	(231)
Customer Advances	(272)
Average Rate Base	$ 19,681

Cost of Capital

6. MDU proposes a rate of return of 11.044 percent, which includes a 13.25 percent return on common equity. Staff has recommended a return of 7.98 percent, including a 10.5 percent return on common equity, inclusion of short-term debt financing and a company wide cost of long-term debt. The rates of return can be calculated as follows:

7. As demonstrated in the foregoing tables, the Staff differs from MDU with respect to the appropriate capital structure as well as the cost of the financing.

Capital Structure

8. Capital structure refers to the makeup of MDU's capital, that is, the mix of debt, preferred stock and equity. Two factors account for the disagreement between Staff and MDU. The first is Staff's inclusion of short-term debt, and the second is Staff's use of the year-end 2001 capital structure instead of MDU's projected capital structure for 2003.

9. In its initial filing, MDU excluded all short-term debt from its proposed capital structure. Staff's rate of return witness, Charles W. King, testified that the makeup of the capital structure used to develop a rate of return should reflect the nature of the rate base to which that return is applied. If the rate base consists solely of capital investments in plant and equipment financed by long-term debt, preferred stock and equity, then it might be appropriate to exclude short-term debt. But MDU's rate base also includes materials and supplies inventories, fuel stocks, and prepayments, which are short-term commitments that will be financed in part with short-term debt. For this reason, he included short-term debt in the capital structure.

10. On rebuttal, MDU witness Craig Keller argued that the items to which King referred, materials and supplies, prepayments and fuel stocks remain relatively constant, not changing materially from one month to another. While classified as short-term assets, they support long-lived assets such as plant, property, equipment and related items. They are therefore financed by long-term debt, according to Keller.

11. At the hearing, King responded to Keller by producing Exhibit 16, which shows the month-to-month amounts of each of the major elements of working capital during the 13 months from December 2000 through December 2001. That exhibit demonstrates net working capital varied from negative $53,000 in January to positive $306,000 in July. King concluded that these widely varying amounts would not have been financed with long-term debt. Keller argued that an unusual refund of a customer advance caused much of the variation shown by King.

12. The Commission finds that MDU has short-term debt and therefore finances part of its business with short-term debt. Accordingly, the Commission will include short-term debt in the determination of cost of capital.

13. The second difference in proposed capital structures relates to the use of historical verses forecasted data. King drew the amounts of debt, preferred stock and common equity from Company supplied data for calendar year 2001. He calculated average long-term debt from Exhibit 2, Statement A, page 2; short-term debt from a response to a data request (Exhibit 15, CWK-1); and preferred stock and common equity from Exhibit 2, Statements A and F, page 1.

14. The capital structure presented by MDU on Statement F, page 3 includes a projected 2003 capital structure. King objected to this use of a projection on the grounds that it is effectively a creation of MDU that has no basis in any verifiable financial statements.

15. On rebuttal, MDU witness Keller argued that NDCC § 49-05-04.1 permits MDU to use a forecast test year and that Staff witness, Michael J. Majoros, had accepted the 2003 test year as the basis for revenue requirements. Keller argued that failure to use a forecast capital structure would result in a "mismatch" with the rest of the revenue requirement calculation. Keller argued that MDU possesses a financial forecasting system that uses known debt scheduling and projects equity by forecasting earnings and deducting dividends.

16. In his oral direct testimony, King pointed out that MDU had used an historical capital structure in its recent electric case. He argued that the purpose of the future test year is to capture exogenous changes that can be objectively determined, such as inflation or the expansion of the system. There is no way of verifying that it will change in the manner MDU predicts. For this reason, King reasoned that most Commissions use recent historical capital structures. Otherwise, MDU has the opportunity to game the regulatory system by projecting a more expensive capital structure.

17. Regarding the issue of historical verses projected, we find in favor of MDU. North Dakota law provides for using a projected test year. There are no assurances that revenues, expenses or cost of capital will actually occur at projected levels. However, the staff's case is predicated on projected revenues and expenses but ignores cost of capital projections. The Commission finds in favor of using a projected capital structure rather than relying on general allegations that MDU might game the regulatory system.

Cost of Debt

18. MDU's cost of debt in 2001 is 9.302 percent, and its projected 2003 debt cost is 9.180 percent. These values are calculated on Exhibit 2, Statement F-1, pages 1 and 3. Those pages show two debt issues, First Mortgage Bonds and Pollution Control Bonds, totaling $133.5 million in 2001 and $132.6 million in 2003.

19. Statement A, pages 11 and 12 of that same exhibit reveals that there is substantially more to MDU's debt than these two issues. As of December 31, 2001, there were $405.2 million in senior notes, $219.7 million in commercial paper, a revolving line of credit of $25 million, and term credit agreements of $11.8 million. Using the cost values shown on those pages, King calculated that the blended cost of MDU's debt is 6.167 percent, more than 300 basis points lower than MDU proposes.

20. The difference between Staff and MDU revolves around what "the Company" actually is. According to MDU witness Keller, only the First Mortgage and Pollution Control bonds relate to MDU Utilities. He argues that all of the other debt pertains to Centennial Holdings, which holds title to the non-regulated operations of the parent Company, MDU Resources Group, Inc. He stated that the two sets of debt are not fungible, and assets of Centennial do not secure the first mortgage liens against electric and gas plant nor do the assets of the utility operations secure the liens against non-regulated assets. Under Keller's argument, MDU has no access to Centennial's debt and vice versa. Further, MDU asserted that it was unfair of staff to use the low cost of a blended rate and ignore the higher cost of a blended capital structure with an equity ratio of nearly 60%.

21. On cross-examination, Keller made it clear that there is no such entity as the Montana-Dakota Utilities Company. The only legal entity is the parent Company, MDU Resources Group, and only that company can issue debt. Neither the utility operation nor Centennial has any debt in its own right. Keller testified that MDU had attempted to build a "firewall" between the debts of MDU Utilities and that of Centennial. The purpose is to protect the utility operations from the effect of default on Centennial's debt. He stated that if Centennial or one of its subsidiaries should go bankrupt, then the bankruptcy judge would not be able to "collapse the corporation" and gain access to the utility's assets. Keller stated that is the reason MDU does not commingle the funds raised for the utility with those raised for Centennial.

22. On cross-examination, Keller conceded that if the bankruptcy of either MDU's regulated or its unregulated operations caused the parent to declare bankruptcy, then

the bankruptcy court would look at all of MDU's assets to satisfy creditors' claims, including those of the regulated utility.

23. King suggested that there might be another, less altruistic reason for attempting to isolate Centennial's debt from that of the utility operations. It is to ensure that ratepayers pay the very high costs of the First Mortgage bonds and receive no benefit from the Company's other, lower-cost financing resources. While the Company may have written its low-cost financing instruments to direct funds to Centennial and its subsidiaries, that was an artifice to game the regulatory system into ascribing only the highest cost debt to regulated service ratepayers. The Company could have used the Centennial funds anywhere had it written the debt instruments differently.

24. MDU's cost of debt is higher than the cost of debt reported by the other investor owned utilities operating in North Dakota. Further, it is nonsensical that the non-regulated enterprises of MDU and thereby more riskier ventures of the corporation are able to secure debt at substantially lower cost than its regulated counterpart. The timing of debt issuances may account for some differences year-to-year but overall and in the long-term one would expect that the cost of debt for the utility operations would be less and certainly not more than 300 basis points higher than the company wide average. Still, the Commission begrudgingly finds in favor of MDU based on the fact that staff was unable to show that MDU had gamed the regulatory system. Such a showing would require an analysis of the timing of plant in service additions compared to the timing of debt issuances before such a verdict could be rendered. Accordingly, the Commission finds in favor of MDU and agrees to use its proposed cost of long-term debt in this proceeding.

Cost of Equity

25. MDU's rate-of-return witness, Dr. J. Stephen Gaske, has recommended a return to equity of 13.25 percent. This return was developed using three variants of the Discounted Cash Flow ("DCF") approach, plus a series of "benchmark analyses."

26. For his DCF results, Gaske drew a distinction between "Investor Requirements" and "Cost of Capital" based on his belief that stock flotation costs, equivalent to 4.75 percent of the return, must be included in the latter. Gaske used a "proxy group" of six companies based on Moody's utility series. His DCF results for these companies were as follows:

	Investor Requirements	**Cost of Capital**
Second-stage Retention Growth	11.94%	12.51%
Basic DCF	12.61%	13.21%
Primary DCF	12.63%	13.22%

27. Gaske's benchmark analyses consisted of four risk premium comparisons using historical differences in earned returns to equity from large and, alternatively, small companies relative to current yields on U.S. Treasury bonds and corporate bonds. He

also identified the recent returns on per-share book value of S&P 500 corporations and Value Line's list of industrial companies. All of his benchmark indicators were higher than any of his DCF returns.

28. Gaske's final selection of 13.25 percent was based on his belief that the risk of MDU's gas distribution business is slightly higher than that of his proxy group of gas distribution companies. He based this belief principally on the smaller size of MDU relative to the proxy companies.

29. King recommended a very different return to equity of 10.5 percent. King followed most of the same procedures as Gaske using the DCF analyses as the principal analytical tool. Like Gaske, King used a comparison group of gas distribution companies. Also like Gaske, King used a forecast of next year's dividends for the dividend yield portion of the DCF formula. King also used both analysts' forecasts and the concept of earnings retention to calculate the growth component of that formula -- as did Gaske. Finally, both King and Gaske adjusted their final recommendations based on their assessments of the risk of MDU's gas distribution activities relative to that of the comparison companies.

30. The explanation for the dramatic 275 basis points difference between the recommendations of the two witnesses lies in the details of the application of the DCF formula. As used by both witnesses, the DCF formula is the sum of next year's dividend yield on MDU's stock and the expected future growth rate in its dividends and earnings.

31. The differences between the Gaske and King applications of the DCF formula relate to the following elements:

1. Inclusion of flotation costs;
2. Selection of comparison companies;
3. Forecast of next year's dividends;
4. Timing of analysts' forecasts;
5. Presentation of the DCF results.

Flotation Costs

32. Gaske drew a distinction between "investor requirement" and "cost of capital," with the difference being cost of issuing new shares in public stock offerings. Gaske quantified this cost as 4.75 percent, based on a representative sample of flotation costs incurred with 34 new common stock issues by natural gas transmission and distribution companies between 1992 and 2001.

33. King agreed with Gaske that flotation costs should be recovered, but he questioned the propriety of applying a ratio for these costs to the entire amount of common equity. Flotation costs are incurred only when a company issues new stock, and then only when there is a public stock offering. Existing stock incurs no flotation cost, and even new stock incurs no such costs if it is distributed as an employee or shareholder benefit either through options or as bonuses.

34. King noted that the effect of Gaske's flotation cost adjustment is to increase his equity return by 60 basis points. When multiplied by the $1.125 billion book equity value of the MDU Resources, Inc., this allowance amounts to $6.75 million annually, which is substantially more than the $5.4 million in flotation costs that the Company has incurred over the past five years.

35. King suggested that if a flotation cost adder is to be used, it should be equal to a reasonable estimate of the annual flotation cost incurrence divided by the entire amount of the Company's equity. In MDU's case, annual flotation costs during the past five years have been about $1.1 million. The Company's total book equity value is $1.125 billion, for a flotation cost allowance of 0.1 percent. This amount is so small as to be lost in the rounding. For this reason, he recommended no explicit flotation cost adder.

36. In rebuttal, Gaske distributed an exhibit that purported to demonstrate that failure to include flotation costs in the return of a company's stock trading at book value would result in the dilution of the book value of that company's shares. On cross-examination, however, Gaske admitted that all of King's comparison companies had per-share market values higher than book value, and that when such companies sell new stock, the effect is to increase book value, not dilute it. On cross-examination, Gaske admitted that his approach to the issue of flotation cost in this proceeding was the same as his approach in Commission Case No. PU-399-01-186 involving MDU's electric rates. Gaske also agreed that most regulatory Commissions do not allow a flotation cost adder.

37. The Commission rejects Gaske's flotation cost adder. Given that staff has provided evidence based on historical information, we find no need to rely on the theoretical information provided by MDU. In addition, Gaske admitted that most regulatory Commissions do not allow flotation costs. The evidence indicates a negligible amount of flotation costs were incurred during the last five years. Therefore, the Commission will not include flotation costs in the determination of return on common equity.

Selection of Comparison Companies

38. Both King and Gaske acknowledged that the heavy involvement of MDU's parent company, MDU Resources Group, Inc., in non-regulated activities effectively precluded using similar companies as the basis for finding the return to equity of its gas distribution business in North Dakota. Necessarily, this required the selection of companies whose primary business is gas distribution. Gaske picked six companies from Moody's list of natural gas distribution companies. King chose 11 companies from Value Line's Investment Survey based on the criteria that they must have investment grade bond ratings, total operating revenues over $100 million, and derive 75 percent of their revenue from gas distribution services. The two lists are as follows:

King Comparison Companies	Gaske Proxy Group
Atmos Energy Corp.	AGL Resources
AGL Resources	Keyspan Corporation
Cascade Natural Gas Corp.	LaClede Group
LaClede Group, Inc.	Northwest Natural Gas
NICOR, Inc.	People's Energy Corp.
Northwest Natural Gas Co.	WGL Holdings, Inc.
People's Energy Corp.	
Piedmont Natural Gas Co.	
South Jersey Industries, Inc.	
Southwest Gas	
WGL Holdings, Inc.	

39. Five of Gaske's six companies are also represented on King's list. The exception is Keyspan Corporation, which King excluded because that company's gas distribution operations accounted for only about one-half of its revenue. We find that King's choice of companies provides a broader and therefore more representative group of companies from which to draw indications as to the cost of equity for gas distribution operations.

Forecast of Next Year's Dividends

40. Both King and Gaske used a forecast of next year's dividends to identify the dividend yield portion of the DCF formula, and both witnesses based this forecast on a percentage of the 5-year annual earnings growth rate predicted by Zacks Investment Research, Inc. Only the percentage differed. King used a factor 1.5 on the assumption that the next dividend increase would be randomly distributed over the coming year. Gaske used a 1.625 inflator of the growth rate and argued that King's factor does not reflect the present value of next year's dividends and dividend increases. The issue is immaterial and the Commission adopts Gaske's inflation factor.

Timing of Analysts' Forecasts

41. Gaske's testimony was filed on April 12, 2002, concurrently with MDU's initial application for an increase in its gas rates. The record does not disclose when Gaske prepared his testimony, but presumably it was in the months immediately preceding the application, which would be February and March of 2002. This would be consistent with the fact that the latest month shown on Gaske's presentation of bond yields is January 2002.

42. King filed his testimony on August 30, 2002, so his information on such factors as share prices and investor expectations was gathered approximately six months after Gaske's.

43. It is not clear how these differences in timing affect the results of the respective analyses. For example, Gaske reported Zacks' consensus 5-year earning growth

forecast for the LaClede Group as 12.0 percent. By the time King prepared his testimony, that forecast had dropped to 4.25 percent. On the other hand, Gaske's forecast growth rate for AGL Resources was 7.03 percent, while that reported by King was 11.42 percent. We find it is appropriate to use King's data because it is more current.

Presentation of the DCF Results

44. Gaske performed three different DCF analyses of his proxy group of companies. One of these analyses, the "basic DCF," was identical to King's "classic DCF" analysis. Both involved combining the forecast dividend yields with Zacks' 5-year consensus forecasts of earning growth.

45. While the methods were the same, the results were quite different. Gaske's six-company proxy group yielded a median basic DCF return, prior to flotation costs, of 12.61 percent and a mean return of 12.95 percent. King, applying exactly the same procedure to his comparison group of 11 companies, found the average (mean) to be 11.29 percent.

46. For his other application of the DCF approach, King added the dividend yield to the growth rate indicated by the earnings retention growth model for each of his 11 comparison companies and found the average to be 12.18 percent. Had Gaske done the same thing, he would have added his average dividend yield of 5.14 percent to his retention growth estimate of 5.5 percent for a DCF return indication of 10.64 percent.

47. Gaske diluted his retention growth rate by mixing it one-third, with two-thirds represented by the Zacks' 5-year earnings forecasts. The result was quite close to the "basic" DCF indications. The median of his "Second-Stage Retention Growth DCF Calculation" was 11.94 percent, the mean 12.25 percent.

48. Gaske presented a third version of the DCF analysis. Gaske put forth what he called his "primary" DCF calculation. This was no calculation at all, but merely the adoption of a range of growth estimates with little support. The range was 6.75 percent to 7.75 percent, asserted by Gaske to have been based on such factors as the 5.5 percent growth in nominal Gross Domestic Product during the past decade, the expected demand growth for natural gas, and investor expectations. None of these considerations support a growth forecast in the range of 6.75 percent to 7.75 percent. The bottom of this range is well above the 5.5 percent GDP growth rate cited by Gaske as well as the 5.5 percent growth indicated by his own earnings retention calculation. The top of the range is above the 7.56 percent growth rate predicted by Zacks for the six companies used by Gaske. This "primary" DCF analysis is biased upward.

49. King also presented a third DCF calculation, but he subsequently discarded it. King calculated a growth factor for each of his 11 comparison companies based on the each company's historical earnings growth between 1997 and 2001. While the average DCF indication of 11.72 percent might appear reasonable, the variation among the individual company observations was so great as to provide little or no probative value.

50. In presenting his DCF returns, King went one step further than Gaske, and provided his estimate of the DCF return requirements of each of his comparison companies. He did not use a mechanical formula because, as he conceded in his testimony, precision is impossible. He described his procedure orally at the hearing as follows:

> ...what I have done in each case is taken the classic DCF return, which is probably the best estimator, and then turned and looked at the retention growth method. If the retention growth looks like it's totally out of whack with the forecast, and in some cases they are – simply no way that the company could be growing as fast or as slowly as the investor survey shows – I modified that classic DCF in the direction of the retention growth.

51. The results of King's procedure were as follows:

	Classic	**Book Value Growth**	**King DCF Return**
Atmos Energy Corp.	12.06%	14.42%	12.5%
AGL Resources	16.67%	11.53%	14.0%
Cascade Natural Gas Corp.	10.25%	15.11%	11.0%
LaClede Group, Inc.	10.29%	11.23%	10.5%
NICOR, Inc.	11.51%	15.96%	12.0%
Northwest Natural Gas Co.	10.65%	10.12%	10.5%
People's Energy Corp.	13.13%	12.07%	12.5%
Piedmont Natural Gas Co.	9.42%	11.24%	10.0%
South Jersey Industries, Inc.	8.15%	12.57%	11.0%
Southwest Gas	10.52%	8.53%	10.0%
WGL Holdings, Inc.	8.99%	11.21%	9.5%
Average	**11.29%**	**12.18%**	**11.23%**

52. Gaske rebutted the fact that the average of King's selected DCF results was lower than the average of either his classic or his book value growth results. This mathematical result stems from King's shrinking of the range of observations. King reduced the effect of the "outlier" highest and lowest observations. In absolute terms, the outliers on the high side diverge more from the mean than those on the low side, even when their percentage difference from the mean is the same. This mathematical distortion can be avoided by focusing on the median observation of each series, that is, the observation where five values are higher and five are lower. The classic DCF median return is 10.52 percent, the median of the book value growth series is 11.53 percent, and the median of King's selected DCF returns is 11.0 percent. Additionally, it should be noted that in arriving at his final DCF recommended returns, King adjusted seven of the classic returns upward and only four downward.

53. On rebuttal, Gaske submitted two mechanical recalculations of King's DCF results, one using a 33%/67% weighting of the book value growth and Zacks' forecasts, the other using a 50%/50% weighting. Both yielded average returns considerably higher than King's 11.23 percent. In performing these calculations, however, Gaske excluded WGL Holdings, ostensibly because, with 74.6 percent of its revenue from regulated gas distribution, it falls outside King's 75 percent criterion. As Gaske admitted on cross-examination, 74.6 percent rounds up to 75 percent. His exclusion biased the results upward because, at 8.99 percent, WGL Holdings' classic DCF return was the lowest in King's comparison group. Moreover, Gaske never explained why his mechanical weightings of King's DCF results were more accurate or valid than King's analysis.

54. Both witnesses support the use of DCF for calculating a reasonable return on equity for purposes of this proceeding. Both provided a basic DCF calculation using the same method even though there are some differences in sample sizes and the age of data. Beyond the calculation of basic DCF, both witnesses make adjustments for their own professional judgment and then are highly critical of each other's results. We find the adjustments for professional judgment are not all that intuitive and appear to be aimed at results rather than fact-finding. Accordingly, we find the use of the basic DCF calculations most useful.

Comparative Risk Adjustments

55. King and Gaske disagree about the final adjustment each witness made to the DCF returns for his comparison companies to reflect the specific risk of MDU's gas distribution operations.

56. Having found that the DCF cost of capital (inclusive of flotation cost) for his proxy companies was in the range of 12.51 and 13.22 percent, Gaske selected 13.25 percent as MDU's capital cost. This upward adjustment from the range of proxy group returns was based on Gaske's belief that MDU's overall risks are slightly above average relative to the proxy group.

57. King's adjustment was in the opposite direction. Having found that the average DCF return for his comparison group is 11.23 percent, King picked 10.5 percent for MDU, which is the midpoint between the group average return and the returns for the least risky companies in the group. The basis of this adjustment was King's belief that MDU is less risky than the comparison group.

58. In his initial testimony, Gaske discussed four types of risk: business risk, regulatory risk, financial risk and market risk. He found that MDU's regulatory and market risks are not significantly different than from those of his proxy group. MDU's financial risk is slightly greater because the bonds of MDU Resources Group are rated slightly lower than the bonds of the proxy companies. The major difference in risk, according to Gaske, relates to business risk. MDU's gas distribution operations are a fraction the size of the proxy companies. Those companies are between six and 46 times the size of MDU's gas distribution operations. Based on the historical difference

between the earned returns of small and large companies, Gaske believes that MDU's smaller size might require a return more than 100 basis points higher than the proxy group. In addition, MDU faces the competition of propane and heating oil for new and existing load in its service territory. Furthermore, its rate structure recovers a substantial portion of its fixed costs in the volumetric component of its rates, and MDU does not have a weather normalization adjustment mechanism. On this basis, Gaske concluded that MDU's North Dakota gas distribution operations face somewhat greater overall business risks than the typical company in his proxy group.

59. King based his conclusion that MDU's gas distribution business is less risky than his comparison group on two facts. First, unlike eight of the 11 comparison companies, MDU's gas distribution operations have no non-regulated business activities. Second, MDU's equity ratio is higher than all but three of his comparison companies, suggesting a lower level of financial risk. He argued that a good case could be made for setting MDU's rate of return at the bottom of the scale of DCF returns for the comparison companies. However, in light of the possibility that the return set in this case may be in effect for an extended period into the future, he selected the midpoint between the lowest returns in his comparison group and the average.

60. In his rebuttal testimony, Gaske argued that King had failed to demonstrate any strong correlation between equity return and the equity proportion or the percent gas distribution revenues in his comparison companies. Gaske presented two correlation studies of these variables. One showed a weak, but measurable correlation between the percent equity in capital structure and King's estimates of DCF returns. The other showed no correlation between equity return and percent gas distribution revenues.

61. King conceded that neither of the two risk factors cited in his testimony are predictors of relative risk, but both are elements of relative risk. A high equity ratio is an indicator of low financial risk, and MDU's equity ratio is about equal to the highest of the equity ratios within his comparison group. The relationship between financial risk and capital structure, which King cites in this portion of his testimony, was also discussed in Gaske's initial testimony at some length.

62. King noted that another element of risk is the amount of non-regulated activity. Regulated activities are less risky than non-regulated activities. When regulated earnings are short, MDU can come to the Commission for an increase in rates. If the Commission grants the rate increase, there is no question whether MDU can collect the additional revenue because of its monopoly status. That is not true of non-regulated activities, which by definition do not have the security of revenue recovery.

63. King cited two further reasons that MDU gas distribution operations have lower risk than many of his comparison companies. Gas companies operating in warmer climates face competition from electric heating that MDU, operating in a cold climate, does not encounter. He testified that in Washington, DC, the Washington Gas Light Company has lost two-thirds to three-quarters of the commercial load to the electric company. For residential customers, heat pumps can combine heating with air

conditioning and so compete with gas. King stated that stand-alone heat pump units that do not draw heat from groundwater would not work in North Dakota's climate because they have to be supplemented with electric resistance heating when temperatures fall below about 45 degrees Fahrenheit.

64. The other difference cited by King relates to the intrusion of gas suppliers into the retail gas market. Some of his comparison companies (he cited Washington Gas and Atlanta Gas Light Company) are required to deliver the gas of independent suppliers. The extreme example is Atlanta Gas Light, which no longer buys gas on behalf of its customers. Instead, merchant gas suppliers buy the gas, and Atlanta Gas Light delivers it to end users on behalf of the suppliers. He testified that Atlanta Gas went from some 600,000 customers to 11. When one of these gas suppliers went bankrupt, Atlanta Gas was "stiffed" for several million dollars. In another example cited by King, Washington Gas has lost two thirds of its commercial load to competitive suppliers. The suppliers have failed to acquire the transportation capacity that Washington Gas had maintained to serve those lost customers, and there is now a risk that in a cold winter, the suppliers will not be able get the required gas to Washington.

65. King observed that MDU does not have the active competition from suppliers that larger companies serving larger service territories have. It therefore does not face the severe business risks associated with these suppliers.

66. King stated that Gaske conducted an apples-and-oranges comparison regarding the alleged risk of small company operations. Gaske has compared the risk properties and required returns of large companies with those of small, stand-alone companies. King says that is not the proper comparison. King states that the relevant objective in this case is to find the risk characteristics of the gas operations of a large company. Being part of a large company provides the security of greater financial strength and also diversification of financial resources. King states that MDU's North Dakota gas distribution operations are not a small, stand-alone company, as are the small companies from which Gaske derives his 100 basis point small-company risk adder. MDU's North Dakota gas distribution operations are merely one part of the overall business of MDU Resources Group. That company is well within the size range of the companies in both King's and Gaske's comparison groups.

67. King stated that while MDU's gas distribution operations are small, they have a lower financial risk than do most of King's comparison companies by reason of a high equity ratio. They have no risky, non-regulated activities, as do most of the comparison companies. While MDU faces competition from propane and oil, as do virtually all gas companies, it does not confront effective competition for its heating load from electricity, as do the comparison companies that operate in warmer climates. Finally, MDU does not have the intrusion of independent gas suppliers into its retail market in anything like the degree that some of the comparison companies have. For these reasons, King's concluded that MDU has somewhat less overall risk than his comparison companies.

68. The arguments about comparative risk are interesting and depict two fairly divergent views. We find some validity in both witnesses' arguments but not to the level of certainty that the Commission can choose one over the other. Accordingly, the Commission will not adjust its DCF findings to reflect the professional judgment of either of these witnesses regarding comparative risk between MDU and the eleven proxy companies.

Gaske's "Benchmark Analyses"

69. Gaske presented two types of "benchmark analyses." In one series, he added the historical differences between Treasury bonds and corporate bonds, on the one hand, and earnings from the common stock of small and, alternatively large companies, on the other. The other benchmark analysis was to identify the recent earned return on book value of S&P's 500 companies and on Value Line's industrial companies. The results of these benchmark analyses are as follows:

Risk Premium Return Based on:	
- U.S. Treasury Bonds	
v. Large Companies	13.3%
v. Small Companies	20.2%
- Corporate Bonds	
v. Large Companies	14.8%
v. Small Companies	22.2%
Alternative Investments	
- S&P 500	21.5%
- Value Line Industrials	29.4%

70. Gaske appears to conclude from these tests that his 13.5 percent cost of capital, derived from DCF results, is quite conservative relative to these benchmark results. King argued that these comparisons are irrelevant. King argued that these results should be disregarded, because their conceptual basis is fatally flawed and the risk premium observations are without value statistically.

71. Gaske's risk premium analysis purports to measure the required return to equity by adding the historical difference in experienced earnings from stocks and bonds to the current levels of bond yields. These historical differences, as measured by Ibbotson Associates, go back to 1926. The theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials.

72. King observed this theory is a statement of faith, not experience, and it defies logic. If investors' short-term expectations are continually being frustrated (as has been the case during the last year), what logic supports the proposition that the sum of those failed short-term expectations represents a valid long-term representation of their expectations? King further argued that it is untrue that the differential in required

returns between bonds and stocks is fixed and unchanging, as this theory postulates. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.

73. King stated that quite apart from this conceptual failing, the stock to bond comparison theory fails statistically. King referred to Exhibit 34 introduced by Gaske that shows annual returns to large company stocks, small company stocks and long-term corporate bonds, and it also shows their differences. King pointed out that the standard deviation of every one of these series is greater than the mean of the observations. King argued that the means therefore lack statistical significance and are useless as a predictive tool.

74. Gaske purports to demonstrate under his alternative equity investment analysis that MDU should be allowed a high return by observing that the returns to book equity on the S&P 500 companies from 1977 to 2000 have averaged 21.47 percent. He also observes that the book equity returns to 746 industrial, retail and transportation companies included in The Value Line Investment Survey have ranged from 27.57 percent to 31.75 percent over the five years 1996-2000. He argues that the average of 29.4 percent, along with the return of 21.47 percent experienced by S&P's 500 companies, suggests that the 13.25 percent he proposes for MDU is quite low.

75. King argued that these comparisons are irrelevant. He pointed out that investors in unregulated industrial, retail and transportation firms have no access to book equity value. The only value that is meaningful for investors in such firms is the market value. That is what an investor must pay to acquire the stock, and conversely, the value an investor will receive by selling the stock. Book equity value in an industrial firm is a purely historical number representing the dollars of original investment in equity capital contributed to (or retained by) the company. It has little relevance to the current market value, even for fairly capital-intensive firms. Since most stocks sell well above their book value, the return that is accessible to investors is considerably less than the 20 to 30 percent noted by Gaske.

76. King noted that book values are relevant for regulated utilities because regulation makes them so. Regulation sets the earnings allowance for such companies relative to a rate base reflective of the book value of the capital invested in utility operations. This condition does not apply to industrial firms.

King's Risk Premium Test

77. King did not attempt to find any absolute value of equity return using the risk premium approach. He agreed that equity investment, being inherently more risky than debt, requires a higher return. But rather than attempt the difficult (and arguably impossible) task of measuring that risk premium, he looked to the trends in bond yields in comparison to past North Dakota Commission findings of equity return to gas companies. King stated that if it appears that bond yields have increased, but he has

recommended a reduced return to equity, then there may be reason to question his finding. On the other hand, if his proposed equity return track with the changes in bond yields, then there is at least a "sanity check" on the propriety of his finding.

78. King identified three gas cases during the past 12 years in which the Commission had found a rate of return to equity. He compared those rates of return with the then-current yields on 10-year Treasury bonds and Aaa Corporate bonds. He then identified the current (that is, August 2002) bond yields. The results of his research are as follows:

Case	Utility	Date	ROE Allowed	10-Yr Treas.	Aaa Corporate
399-90-820	MDU	July 30, 1991	12.0%	8.27%	9.00%
400-95-559	NSP	June 7, 1996	12.0%	6.91%	7.71%
400-00-521	NSP	June 27, 2001	11.5%	5.28%	7.18%
399-02-183	**MDU**	August, 2002	**10.5%***	4.35%	6.45%

79. The Commission takes notice of the benchmark analyses prepared by Gaske and King. Again, these benchmark analyses or reasonableness tests are intended to bolster each witness's use of DCF and their own feelings about what is or isn't a fair return on MDU's natural gas investments. We take notice of the arguments for what they are but find no compelling reason to adjust the outcome of the basic DCF calculation. In light of current economic conditions within the United States, Gaske's benchmark returns using risk premium and alternative investments are so high that they are unreasonable. On the other hand, we find no reason to try and track Commission ordered returns on equity to interest on notes or bonds either. Therefore, given the above considerations and conclusions, we find that the current market expectations for a natural gas distribution company such as MDU is an opportunity to earn 11.329% on its common equity, as follows:

Proxy Company	Div. Est.	EPS Growth	Growth Factor	Div Growth	Next Yr Div.	50-day Price	Div. Yield	DCF Return
Atmos Energy	$ 1.18	6.43%	62.5%	4.02%	$ 1.23	$ 21.63	5.67%	12.105%
AGL Resources	$ 1.08	11.42%	62.5%	7.14%	$ 1.16	$ 21.76	5.32%	16.737%
Cascade Natural	$ 0.96	5.25%	62.5%	3.28%	$ 0.99	$ 19.69	5.04%	10.286%
LaClede Group	$ 1.34	4.25%	62.5%	2.66%	$ 1.38	$ 22.65	6.07%	10.323%
NICOR	$ 1.84	6.10%	62.5%	3.81%	$ 1.91	$ 35.06	5.45%	11.548%
Northwest Natural	$ 1.26	6.06%	62.5%	3.79%	$ 1.31	$ 28.28	4.62%	10.684%
People's Energy	$ 2.08	6.80%	62.5%	4.25%	$ 2.17	$ 34.00	6.38%	13.178%
Piedmont Natural	$ 1.60	4.67%	62.5%	2.92%	$ 1.65	$ 34.45	4.78%	9.450%
South Jersey Industries	$ 1.50	6.00%	62.5%	3.75%	$ 1.56	$ 32.85	4.74%	10.737%
Southwest Gas	$ 0.82	6.80%	62.5%	4.25%	$ 0.85	$ 22.79	3.75%	10.551%
WGL Holdings, Inc.	$ 1.27	3.65%	62.5%	2.28%	$ 1.30	$ 24.21	5.37%	9.015%
Average DCF Return								11.329%

Net Regulated Income

Revenues

80. Both MDU and staff agree on projected volumes for sales and transportation customers including the associated revenues and cost of gas. We find that the projections are reasonable and adopt them for purposes of determining just and reasonable rates.

Other O&M Expense: Bonuses and 2003 Labor Expenses

81. In its application, MDU projects labor cost increases of 3.15% and 3% for 2002 and 2003, respectively. MDU argued that the increases are smaller than the present labor market. Included in the projected labor cost increases is compensation for bonuses.

82. Staff witness Majoros proposed to eliminate bonuses from the forecasted test year and to hold test year labor costs to their 2002 levels. MDU included average bonuses for the years 1999-2001 in the amount of 6.1 percent of labor costs. Applied to the $8,239,000 in labor costs in 2002, the bonus elimination by staff comes to $503,000. The 2003 labor cost increase eliminated by Majoros amounts to $236,000. These direct labor cost adjustments reduce payroll taxes by $40,000 in 2002 and $60,000 in 2003.

83. Majoros testified that given the state of the economy and the fact that MDU is requesting a rate increase, it would be unreasonable to include bonuses or 2003 wage increases in the test year revenue requirement. Majoros accepted the 2002 labor cost increase, but objected to extrapolating that increase through 2003.

84. MDU witness, Richard D. Spratt, MDU's Vice President – Human Relations, argued that bonuses are an integral part of overall compensation philosophy to remain competitive with other employers. Part of that compensation is intentionally put at risk in the form of bonuses that are paid on the basis of various goals, including MDU's overall profitability. Spratt presented the results of an industry survey that showed most

utilities pay bonuses not only to management employees, but to salaried and hourly employees as well. Spratt stated that the elimination of bonuses would risk rendering MDU uncompetitive relative to other employers.

85. Staff witness Majoros argued that bonuses should not be built into rates because they are primarily paid out based on the profitability of the company. Spratt testified that two years ago, presumably in 2000, 75 percent of MDU's employees received a 7 percent bonus. Last year, 2001, their bonus was 0.6 percent. Presumably, these bonus levels reflect the fact that in 2000, MDU earned 11.96 percent on its North Dakota Gas Operations, but in 2001, it reported only 1.6 percent.

86. C. Wayne Fox, President of MDU Utilities Company, stated that from 1994 through 2001 the Consumer Price Index has risen nearly 20 percent, and in spite of that increase MDU has been able to hold-the-line on gas rates by finding ways of operating the business more efficiently and taking advantage of new technology. MDU even reduced its rates in 1999 through improved efficiency. Fox testified that MDU has reduced its employees by 30 percent since 1994. In that year there were 248 customers per MDU employee. In 2001, one employee was serving 370 customers. MDU witness, Rita Mulkern testified that while past employee reductions are reflected in the 2001 base period data, no further reductions are forecast for 2002 and 2003.

87. We find in favor of MDU. We believe the overall wage increases projected by MDU are fair and reasonable. The Commission believes that how those raises are distributed remains the responsibility of MDU's management and therefore will not delineate between the portion attributable to a general wage increase or bonuses. Further, we do not find the practice of paying bonuses based on profitability objectionable. In fact, the payment or lack of payment of bonuses depending on profitability smoothes out earnings and at the same time puts pressure on employees to perform. We do not accept the argument that because MDU has been able to reduce its workforce and beat inflation in recent years that it should be expected to do so forever more. Accordingly, the staff adjustment to Taxes Other Than Income to eliminate related payroll taxes is also denied.

Other O&M Expense: SISP

88. The Supplemental Income Security Plan ("SISP") is a plan that provides supplemental pension benefits to key employees. "Key employees" are officers, directors and senior managers of MDU Resources and MDU Utilities. The plan is expected to cost $259,000 in 2002 and $265,000 in test year 2003.

89. SISP was initiated in 1982, but MDU never sought its inclusion in rates until Case No. PU-399-01-186. The order states that staff characterized SISP as a double pension for a few key employees and that the plan lacked symmetry. Staff cautioned the Commission against such a plan given the Enron debacle and the payments it made to key employees. In its April 24, 2002 decision in that case, the Commission accepted Staff's position. The Commission concluded that it is inappropriate for ratepayers to bear the expense of the SISP costs.

90. MDU witness, Richard A. Espland, acknowledged that his testimony was essentially the same as it was in Case No. PU-399-01-186. Espland acknowledged that SISP benefits only MDU's high salaried employees with income ranges from a low of $75,000 to its president at around $250,000 to $300,000. Espland also agreed that none of the Public Utility Commission's in the jurisdictions where MDU provides natural gas utility services have approved a ratepayer funded SISP program. The Commission took administrative notice of its Findings of Fact, Conclusions of Law and Order in Case No. PU-399-01-186.

91. We find that the inclusion of an extra pension for key employees is still inappropriate and unnecessary as a ratemaking expense. We determined that SISP was inappropriate in Case No. PU-399-01-186 and none of the arguments have changed. Accordingly, we find no reason to order differently in this case. MDU's projected expense of $265,000 for SISP costs is denied.

Other O&M Expense: Rate Case Expense

92. MDU proposes to amortize $168,000 in rate case expenses over three years at $56,000 per year. Staff witness Majoros proposes to amortize the same amount over five years at $34,000 per year, for a difference in annual cost recognition of $22,000. Mulkern suggested that if the five-year amortization is adopted, the unamortized balance should be included as a rate base addition.

93. The basis of Majoros' proposal is the historical period between rate cases. Fox stated in his direct testimony that MDU's last rate increase, in Case No. PU-399-94-297, was decided in 1994, and a rate reduction occurred in 1999 in Case No. PU-399-96-325. This represents two rate cases in eight years, or one every four years. MDU has rounded down to three, and Staff has rounded up to five.

94. We find that the recent trends of a case every four years argues for an amortization period of four years. Accordingly, the Commission finds that ratemaking expense is $42,000 per year or a reduction to the company's projection of $14,000.

Other O&M Expense: General Inflation Adjustment

95. In 2001, MDU incurred $89,780,000 in operating and maintenance expense, of which $76,842,000 represented the cost of acquiring gas. Of the remaining $12,938,000 O&M cost relating to distribution, MDU developed specific forecasts for $9,249,000 based on projected changes for various categories of costs, e.g. labor, benefits, insurance, advertising. The remaining catchall category of $3,689,000 is projected to increase 2.8 percent annually at the assumed rate of general inflation.

96. Majoros noted that the Commission had never previously allowed this sort of inflation-based adjustment; that some sort of incentive to generate efficiency should remain and that some of the catchall provision includes fixed costs that are not subject to inflation.

97. MDU argued through its witness, Ms. Mulkern that these types of expenses are subject to inflationary pressures and that past Commission decisions rejecting this adjustment are no excuse for ignoring inflation in this proceeding.

98. We reject the idea that we have ignored inflation in the past or that we would in this proceeding. Instead, MDU has recommended that the Commission give it consideration for a number of specific adjustments that go beyond the 2.8% inflation factor and then add on 2.8% for any remaining and unadjusted expense levels. According to Statement N, Page 1 of MDU's application, the company has requested an overall increase in Other O&M expenses of more than 5% per year for its projected 2003 test year in comparison to 2001 actual expenses. Finally, the Commission order in this proceeding grants an increase in Other O&M expenses that exceeds the general inflation factor of 2.8% which is not necessarily indicative of changes in natural gas distribution costs.

99. MDU's proposal to increase "other" O&M costs at the rate of inflation through 2003 is rejected. The elimination of this adjustment reduces test-year expenses by $209,000.

Depreciation

100. Staff asserted that test year depreciation expense should be reduced by $2,172,000. MDU's current depreciation expense is based on rates developed in a 1991 study performed by Stone & Webster. Staff witness Michael J. Majoros performed a series of studies that suggested MDU's depreciation rates are excessive. First, he found that annual depreciation accruals during the past five years have exceeded utility construction and acquisition by $28.5 million. When common plant construction and acquisition is added, the five-year accruals still exceeded expenditures by $409,000. While it is not the purpose of depreciation to fund construction, this comparison indicates that MDU has obtained substantial cash flow from depreciation. Majoros noted that in *Lindheimer v. Illinios Bell Telephone Company,* 292 U.S. 151 (1934), the Supreme Court found that excessive depreciation results in the extraction of capital from ratepayers.

101. Majoros next observed that as of the end of 2001, the ratio of depreciation reserve to the original cost of distribution plant is 70.7 percent. Based on his experience, he testified that this level of depreciation reserve is extraordinarily high and suggests that prior depreciation rates have been excessive. Majoros stated that the likely source of these excessive rates is the 140 percent negative salvage adjustment for Account 380 – Services.

102. Majoros adjusted MDU's salvage factors based on an inconsistency between the net salvage assumed in the Stone and Webster study and actual net salvage that MDU has experience during the past five years. The Stone & Webster study developed depreciation rates that resulted in a large recovery of "negative salvage," that is, cost of removal. Specifically, its depreciation rates were designed to recover total gas plant of $102.5 million plus negative salvage (removal) costs of $46.9 million.

103. Majoros testified that MDU's actual net salvage experience has been positive. In every year since 1997, he testified that MDU has received more in salvage value for its retired gas and common plant than it has paid in removal cost. The total cumulative 5-year net positive salvage receipts for gas plant have amounted to $1,444,452. For common plant, net positive salvage receipts have come to $5,529,260.

104. To correct for over-recovery of net salvage, Majoros proposed to adopt the Stone & Webster lives and survivor curves for each account with no net salvage overlay. The account-by-account depreciation rates would thus represent pure depreciation, that is, solely the recovery of original cost. To recognize net salvage, Majoros proposed to deduct from total annual depreciation the average annual amount of net positive salvage for gas plant, plus the net positive salvage of common plant distributed between gas and electric operations based on their respective net salvage amounts. Under Majoros' proposal, total depreciation of test year plant would be $1,937,000. The annualized positive salvage offset would be $848,000, for a net test-year depreciation expense of $1,089,000.

105. Majoros noted that, in addition to matching net salvage accruals with actual net salvage experience, his treatment of removal costs conforms to Generally Accepted Accounting Principles ("GAAP") as recently defined in Statement of Financial Accounting Standards No. 143 ("FAS 143"). That standard, which MDU must adopt this year, requires companies to determine whether they have a legal obligation to retire property and incur the cost of removal or dismantlement. If they do, they must declare the present value of the future "asset retirement obligation" costs as a liability on their books to be amortized over the remaining life of the asset. If they do not, then the American Institute of Certified Public Accounts' Statement of Position on Property, Plant and Equipment would require that these costs be expensed as they are incurred.

106. Majoros testified that MDU has not determined whether it has asset retirement obligations, or what the present value of those obligations might be. For this reason, Majoros' adjustment reflects net salvage experience as a rolling five-year average of actual net removal costs.

107. In rebuttal, MDU witness John A. Jeter, a retired accountant from Arthur Anderson & Co. argued that Majoros had not done a depreciation study, that his review of the current depreciation rates is superficial and contains many errors, and that he has no basis for proposing changes in depreciation rates. According to Jeter, the current depreciation rates are based on a comprehensive study prepared in 1991 and used beginning 1994. He argued that no adjustment of depreciation rates should be entertained until the current depreciation study underway is completed and an appropriate review has taken place.

108. Jeter asserted that the 1991 depreciation study by Stone & Webster is a much more reliable source of information regarding net salvage than a cursory look at net salvage for all accounts over a five year period. Jeter did not explain the reason, nor

did he refute Majoros' observation that the Stone & Webster study had recommended large negative salvage allowances, while MDU's actual net salvage experience has been positive in recent years.

109. Jeter disagreed with Majoros' net salvage proposal to adjust overall depreciation by $848,000 based on the past five years' actual experience. He observed that the net salvage amounts used by Majoros varied from year to year and reflected the sale of an office building for approximately $4.6 million. Jeter further contended that Majoros allocated common property net salvage based on the direct net salvage amounts of the gas and electric operations, which is not the basis used by MDU. Jeter failed however to mention how MDU does allocate these common net salvage amounts or whether the difference in methods is material.

110. MDU asked the Commission to defer any consideration of depreciation until its new depreciation study, currently being conducted by AUS Consulting, is completed by the end of this year.

111. We find it unfortunate that the depreciation study currently underway could not be completed prior to the hearing. MDU has agreed to submit the new depreciation study for review by January 31, 2003 as a continued issue in this proceeding, subject to the standard and customary contested case process with all parties having rights of discovery, testimony, rebuttal testimony, hearing and briefing. MDU's depreciation filing will include gas and common plant facilities. Any resulting change in depreciation expense ordered by the Commission at the conclusion of the review will be reflected in rates on a prospective basis.

112. The Commission anticipates that this review should take no longer than six months from the date MDU files its new depreciation study. In the interim the Commission will allow MDU to implement rates reflecting the findings and conclusions in the instant order together with MDU's current depreciation rates. The Commission recognizes that the instant decision is a final decision as to all issues except for the depreciation issue, which is continued pending the filing and review of a new study. MDU's recently filed letter reflects MDU's agreement with this understanding.

113. Staff's adjustment reducing depreciation expense by $2.172 million is rejected.

114. From the foregoing, the Commission finds that MDU's projected Net Operating Income for 2003 is as follows:

Description	MDU	Adjustments	Commission
Sales	$ 67,962	$ -	$ 67,962
Transportation	900	-	900
Other	287	-	287
Total Revenues	$ 69,149	$ -	$ 69,149
Cost of Gas	$ 50,072	$ -	$ 50,072
Other O & M Expense	14,354	(488)	13,866
Total O & M Expense	$ 64,426	$ (488)	$ 63,938
Depreciation	3,261	-	3,261
Taxes Other Than Income	1,352	-	1,352
Current Income Tax Expense	(1,961)	192	(1,769)
Deferred Income Taxes	1,612	-	1,612
Total Expenses	$ 68,690	$ (296)	$ 68,394
Net Regulated Income	$ 459	$ 296	$ 755
Income Tax Calculation:			
NOI before Income Taxes	$ 110		$ 598
Interest Deduction:			
Rate Base	$ 19,681		$ 19,681
Weighted Cost of Debt	3.951%		3.969%
Interest Expense	$ 778		$ 781
Other Deductions	$ 4,282		$ 4,282
Taxable Income	$ (4,950)		$ (4,465)
Tax Rate	39.61%		39.61%
Income Tax Expense	$ (1,961)		$ (1,769)

115. From the foregoing, the Commission calculates that MDU's additional revenue requirement for the opportunity to earn 11.329% on common equity invested in North Dakota in 2003 is:

Change in Revenue Calculation	
Rate Base	$ 19,681
Weighted Cost of Capital	9.883%
Required Return	$ 1,945
Return Earned	$ 755
Difference	$ (1,191)
Tax Factor	1.656
Required Change in Revenue	$ (1,972)
Rate Increase Required	2.9%

Sale of Corporate Building

116. In this proceeding, it came to the attention of the Commission that MDU transferred the ownership of its Schuchart Building from the utility business to a non-regulated subsidiary. According to MDU's witness Keller, the building was transferred to recognize that less and less of the corporate business is related to the utility operations. The building was transferred at net book value without the benefit of a fair market value assessment. It appears that some after-the-fact analysis has been done to suggest the transfer was fair to ratepayers. The Commission wishes to remind MDU, as it would all public utilities, that the utmost care must be taken in completing such transactions. At a time in our history when corporate activities are being heavily scrutinized, it is imperative that MDU conduct business in an open and transparent manner, such that there is not even the slightest hint of corporate greed or chicanery.

Cost Allocation and Rate Design

Class Cost of Services Study

117. A class cost of service study is an analysis of the embedded or incremental costs of providing utility services to the customers or classes of customers that either cause these costs, or to whom these costs can reasonably be allocated. The purpose of performing a class cost of service study is to provide an indication of what it costs to provide utility service to each customer class and what rate of return each class provides. In prior rate applications the Commission has not adopted any particular study but has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers.

118. MDU Witness Tammie Aberle sponsored an embedded cost of service study for the year ended December 31, 2001. This study allocated all of MDU's recorded distribution, general and gas-related common plant among seven categories of customers:

- Residential
- Firm General
- Air Force
- Small Interruptible Sales
- Small Interruptible Transport
- Large Interruptible

119. The costs allocated to the respective customer classes were in turn subdivided into three categories:

- Capacity related costs vary with the amount of gas send out on the peak days of the year. Examples include the sizing of distribution mains and meters to account for the maximum volume of gas handled on any one day.
- Throughput related costs vary with the total amount of gas distributed throughout the year. Uncollectible accounts are an example of this type of cost.

- Customer related costs vary with the number of customers. Examples include the cost of meters, services and billing.

120. The only disagreement relating to this cost of service study concerned the allocation of the cost of mains. Mains constitute 39.1 percent of MDU's gas distribution plant, but their relevance exceeds even this percentage. That is because general and common plant, which account for another 20 percent of total plant, are allocated as overheads to the direct investment, of which mains are the largest component.

121. In its initial cost of service study, Statement M of Exhibit 2, MDU allocated mains 64 percent on the basis of peak two-day throughput during the year and 36 percent on the basis of the number of customers.

122. King objected to the allocation of a portion of mains costs on a customer count basis. The arguable justification for doing so is that the purpose of the mains system is to reach customers, and that when more customers are added, the mains system has to be extended. King argued that this is true only at the very edges of the system, where gas mains are being extended to serve new developments. Even then, the added cost of mains for new customers can vary dramatically depending on the location of those customers.

123. King testified that another purpose of mains is to deliver gas. He argued that the value derived and the benefits received from the mains system are more related to the amount of gas delivered than to the number of customers. One customer receiving twice as much gas as another customer enjoys exactly twice the BTU heating content. The two cannot be equated in terms of benefit received, yet that is what a customer allocation of mains does. He illustrated his point by using the example of a section of main that changes the number and makeup of customers over a period of several years, but the amount of gas delivered remains the same. The weighting of that main in the cost of service study would change under a customer allocation, but it would remain the same (although shifted among customer classes) if the allocation were made on the basis of annual throughput.

124. King therefore asked that MDU conduct an alternative study to allocate half the mains cost according to the classes' two-day peak throughput and half on the basis of annual throughput.

125. On rebuttal, Aberle objected to King's revisions, arguing that main additions are not made only on the edges of the system to provide new service to developments, but are also required to enhance system integrity and maintain pressure throughout the system as customer additions are made. She objected that heating content has no impact on the cost of the mains system. She also objected to the use of a peak-day allocator that assigns costs to the interruptible class and a throughput allocator that assigns costs to the transmission customers. She argued that both of these allocations violate practices previously approved by the Commission. She submitted yet a third

cost of service study, one, which allocates mains, based 50 percent on throughput at the distribution level and 50 percent on peak day use by firm customers.

126. The results of the three costs of service studies show the rate of return from each customer class as follows:

	MDU Statement M	**King CWK-7**	**Aberle TAA-4**
Residential	3.083%	7.731%	6.367%
Firm General	3.998%	2.161%	1.106%
Air Force	50.281%	3.502%	69.369%
Small Interruptible Sales	83.992%	38.040%	40.905%
Small Interruptible Transport	169.437%	48.490%	57.738%
Large Interruptible	78.644%	-0.673%	27.320%
Total North Dakota	6.439%	6.442%	6.442%

127. As noted earlier, the Commission has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers. We appreciate the information provided by each of the studies because it quantifies the impact that a change in allocation factor has on the rates of return from customer classes. The studies also show that, regardless of the allocator used to allocate mains to customer classes, some customer classes are providing a much higher return on MDU's investment to serve than are other customer classes. All three studies indicate the small interruptible classes generate a much higher than average rate of return while two of the studies indicate the same is true for the air force and large interruptible classes. The third study proposed by King indicates lower rates of return from the Air Force and large interruptible classes, but we are concerned that this study may not adequately recognize the value of controlling system peaks with interruptible load.

Rate Design

128. In its initial application, MDU made a number of rate design proposals, as follows:

- Increase residential and firm general service rates by 4.6 percent, reduce the small interruptible class rates by 4.1 percent, and leave the Air Force and large interruptible rates unchanged;
- Separate the commodity rate into a Distribution Delivery Charge and a Cost of Gas charge, eliminating the Purchased Gas Cost Adjustment;
- Eliminate the declining block rate form from the commodity charges and substitute a flat per-dekatherm ("dk") rate;
- Change the customer, or "Basic Service Charge" from a monthly to a daily charge;
- Increase the Basic Service Charges by very large percentages, for example, the residential charge increases from $6.50 to $11.70, the small firm service charge from $8.50 to $24.00 and the large firm service charge from $17.00 to $51.00.

- Eliminate the residential seasonal rate;
- Increase the penalty for failure of interruptible customers to interrupt from $10 to $50 per dk;
- Increase the return check fee to $20;
- Increase the reconnection fees for seasonal customers to match the avoided Basic Service Charges;
- Increase the reconnection charge for disconnected customers for nonpayment to $30;
- Modify the Firm Gas Extension Policy Rate 120 and 124 to reflect MDU ownership of all prospective service lines.

129. King recommended that the Commission accept a number of these proposals regardless of whether MDU's overall revenue is increased, decreased, or remains unchanged. The Commission finds the following consensus proposals should be approved:

- The commodity rate should be separated into two clearly distinct rates, the Distribution Delivery Charge and the Cost of Gas Rate.
- The declining block rates should be eliminated, and the revenue collected through the higher initial block rates should be reallocated to the Basic Service Charge.
- The residential seasonal rates should be eliminated, since there are no customers on these rates.
- Penalties for failure to interrupt should be increased, since MDU believes the current penalties are not sufficient to ensure interruptible customers respond to their calls for interruption or curtailment.
- The reconnection charges for seasonal customers should be adjusted to match the higher Basic Service Charges resulting from the elimination of declining commodity blocks.
- MDU's proposed modifications to the line extension policy should be adopted.

130. King recommended that the Commission reject MDU's proposal to increase the reconnection charge for discontinued service to $30. While MDU claimed that this is a cost-based rate, King suggested that there is a legitimate public policy reason for not increasing this rate. The customers to whom this charge applies are almost certainly the lowest income customers. Otherwise, they would not have been disconnected. Since they have to pay their arrearages anyway, they are likely suffering some difficulty getting reconnected. To impose on them yet more cost, such as an increase in the reconnection fee, might prevent some of these customers from obtaining vital utility service. MDU did not respond to King's recommendation. We agree with the policy considerations asserted by King and find MDU's proposal to increase the reconnection charge for disconnected customers should be denied.

131. MDU proposed to increase the returned check charge to $20 to reflect the current going rate charged by banks and other businesses when a check is returned for non-payment. However, MDU did not present any studies or other specific information to indicate its actual cost of returned checks. We find that returned check charges

should be based on cost and absent a showing by MDU that the proposed new rate is based on cost, MDU's proposal should be denied.

Rate Allocation Among Customer Classes

132. MDU proposed that residential and firm general service customers receive a rate increase of 4.6 percent, that the Air Force and large interruptible customers receive no increase, and that the small interruptible class receives a reduction of 4.1 percent. In the past the Commission has not approved rate reductions to some classes when granting an overall increase. Consistent with past Commission practice, we will not authorize any decrease for the small interruptible class. If a class receives a decrease when other classes receive an increase, the amount of the increase to the other classes will be higher. Revenue lost from giving one class a decrease must be made up by the other classes, thus increasing their burden.

133 The Commission finds the overall results of the class cost of service studies indicate that rates of return from the residential and firm general service classes are significantly less than those from the other classes. We share the desire to move towards more equalized rates of return between customer classes. The relatively small amount of revenue increase being granted in this case provides an opportunity to increase the rates of return from the firm general and residential classes without unduly burdening customers. Therefore, we will allow MDU to assign approximately equal percentage revenue increases reflecting the overall increase authorized to the residential and firm general service customer classes and approximately zero percentage increases to the other customer classes.

Monthly Customer Charges

134. King supported MDU's proposal to eliminate declining block commodity rates on the grounds that this rate structure implicitly encourages customers to use more gas, and it thereby discourages conservation. To the extent that it collects fixed customer costs in the commodity rate, it misstates the cause of the costs. Declining block rates also allow customers who use minor amounts of gas to escape the cost of providing the basic elements of service to them. As stated above, we agree with King that the declining block rate should be eliminated to more closely reflect cost causation in rates to customers.

135. Using MDU's billing unit counts for the year 2001, King calculated the revenue-neutral increase in monthly customer charges that would result if the present declining block rate structure were eliminated from each rate schedule. Under King's revenue neutral proposal, the resulting monthly customer charges would be as follows:

	Current	**Rev. Neutral**
Small Residential	$6.50	$8.43
Large Residential	$13.00	$15.31
Small Firm Service	$8.50	$14.34
Large Firm Service	$17.00	$45.16

135. King also recommended that the Commission consider MDU's proposal to convert the customer charges from monthly to daily charges. The proposal simplifies the calculation of the charge when customers are taking gas for only part of a month. We agree and find that MDU's monthly customer charge should be converted to a daily customer charge as proposed.

136. King had misgivings about MDU's proposal to increase customer charges dramatically, even for the classes for which it was proposing rate reductions or no rate increases. MDU witness Russell Feingold contended that shifting revenue recovery from the commodity to the customer component allows MDU to recover much more of its fixed costs on a non-weather sensitive basis. He asserted that this shift also protects customers from the volatility in their gas bills caused by variations in weather.

137. King was concerned with the issue of rate continuity. The sort of changes proposed by MDU would result in dramatically different bills for different types of customers. Very low-use customers might find higher percentage increases in their average monthly bills. Customers accustomed to low gas bills in the summer, that possibly offset high electric bills, could be surprised by the increase in their summer gas invoices.

138. King was further concerned that customers may resent high monthly customer charges. When most of the cost of gas is based on the level of gas consumption, customers can avoid high gas bills by conserving gas. But no amount of conservation permits a customer to avoid a monthly customer charge. As long as this charge is not a major portion of the bill, it is likely to be acceptable to most customers. But if it looms as a major element in the cost of gas service, customers will come to regard it as a tax from which there is no escape.

139. King recommended that customer charges should not be increased by more than twice any overall percentage increase. This would be in addition to the increases in customer charges that result from the flattening of the declining block rates. King testified if rates are reduced, the reductions should be flowed entirely into the commodity component of each rate schedule. King asserts that customer charges should not be increased when rates are reduced, except to eliminate the declining block feature of the rate schedules.

140. The Commission agrees that customer charge increases should be limited and will adopt King's recommendation for residential and small firm general service customers because customer charges are a more significant portion of their bill. We find the remaining monthly customer charges proposed by MDU should be approved. The resulting customer charges are:

	Current Monthly	Proposed Monthly	Proposed Daily	Authorized Monthly	Authorized Daily [1]
Residential Service		$ 11.70	$ 0.39	$ 8.91	$ 0.29
Small Meters	$ 6.50				
Large Meters	$ 13.00				
Firm General Service					
Small Meters	$ 8.50	$ 24.00	$ 0.80	$ 15.16	$ 0.50
Large Meters	$ 17.00	$ 51.00	$ 1.70	$ 51.00	$ 1.70
Air Force					
Firm	$ 35.00	$ 135.00		$ 135.00	
Interruptible	$750.00	$1,000.00		$1,000.00	
Small Interruptible					
Sales	$ 35.00	$ 100.00		$ 100.00	
Transport [2]	$ 35.00	$ 150.00		$ 150.00	
Large Interruptible					
Sales	$450.00	$ 675.00		$ 675.00	
Transport [2]	$450.00	$ 725.00		$ 725.00	

Notes:

1. Daily = Monthly X 12 / 365.25
2. Customer charge authorized for transportation service includes roll-in of $50 nominating fee currently charged separately under existing tariff.

Distribution Delivery Stabilization Mechanism

141. MDU proposes that if the Commission disapproves of MDU's increases in customer charges, it should adopt a Distribution Delivery Stabilization Mechanism ("DDSM") as an alternative. As described by Feingold, the DDSM would modify the effects of weather variations by adjusting bills for the difference between the actual heating degree-days and heating degree-days under normal weather. Following a cold winter, the excess in each class's revenue from the greater number of heating degree days would be divided by the projected annual sales volumes in that class and credited to all customers over the following year on a per-dk basis. Similarly, the revenue shortfall from a warmer than normal winter would be collected through a surcharge in the following year.

149. King testified that the value of a weather normalization adjustment should be to ameliorate the volatility in customer bills caused by variations in weather, and particularly the effect of unusually cold winters. In such winters, ratepayers typically experience a "double whammy." First, they consume more gas than usual, which increases their bills even if the price of gas remains the same. Then, because cold winters are usually a widespread phenomenon, the demand for gas is higher across the continent, which means that the price of gas is higher. The result is a further inflation in

their bills. Just this sort of inflation occurred across the country during the winter of 2000-2001.

150. King suggested that MDU's proposal could result in a "triple whammy." If North Dakota experiences an unusually warm winter, and it is followed by an unusually cold winter, ratepayers during the cold winter, already hard-hit, would find themselves paying a surcharge to make up for the shortfall in revenue collections in the previous year. The effect of MDU's program could be to increase, not decrease the volatility in customers' bills from year to year.

151. The Commission finds that MDU's alternative proposal should be denied, primarily because of its delayed effect. For a weather normalization adjustment to be beneficial to ratepayers and not just the utility, it must affect their bills when the unusual weather is occurring, not after it has occurred.

From the foregoing Findings of Fact, the Commission makes its:

Conclusions of Law

1. The Commission has jurisdiction over the parties and the subject matter of this proceeding.

2. MDU is entitled to rates and charges necessary to provide it an opportunity to earn a reasonable rate of return on its North Dakota natural gas property, used and useful, for the service and convenience of the public in North Dakota.

3. The rates authorized by the Commission herein will provide MDU with the opportunity to earn a reasonable rate of return on its property used and useful for the service and convenience of the public in North Dakota.

4. The depreciation issue in this proceeding is continued for the purpose of filing and review of, and decision on, a new depreciation study.

5. This order constitutes a final determination of all issues in this proceeding except the depreciation issue.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

Order

The Commission orders:

1. MDU may implement a rate increase for service rendered on and after December 12, 2002, sufficient to produce a total annual revenue increase of $1.972 million.

2. MDU shall file revised tariff sheets for Commission approval consistent with the foregoing findings of fact and conclusions of law.

3. MDU shall file its new depreciation study as soon as possible, but no later than January 31, 2002.

PUBLIC SERVICE COMMISSION

Anthony T. Clark	**Susan E. Wefald**	**Leo M. Reinbold**
Commissioner	**President**	**Commissioner**

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

CONCURRING OPINION
Commissioner Susan E. Wefald

December 10, 2002

I concur with all of the findings of facts and conclusions on law in this case except for finding 87. The Commission should not include bonus money for MDU employees as an element of a rate case.

If company profitability drives bonuses, as it appears to, then it is altogether inappropriate to include bonuses in a revenue requirement that drives a rate increase. As staff stated in its brief, "The reason MDU needs the rate increase is that it is not profitable. If it becomes profitable as result of a rate increase, that profitability will not have come about because the employees have performed particularly well. To the contrary, it will be because the employees have not performed well, and MDU needs rescue from the Commission. The revenue requirement imposed on ratepayers should not include rewards for poor performance. For this reason, bonuses should be disallowed." (page 14, Public Service Commission Staff Brief, filed November 15, 2002)

The overall wage increases projected by MDU are fair and reasonable. However, eliminating $503,000, which is equal to 6.1 percent of total approved labor costs in 2002 of $8,239,000, is prudent. This would reduce the amount of pay increase needed in 2003 by $236,000 (see finding 82). If the amount of the bonuses was eliminated, MDU would still have the ability to allocate any warranted bonus money with the remainder of the money in labor cost increases and the elimination would provide an incentive for company employees to find further cost savings and increase profitability.

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
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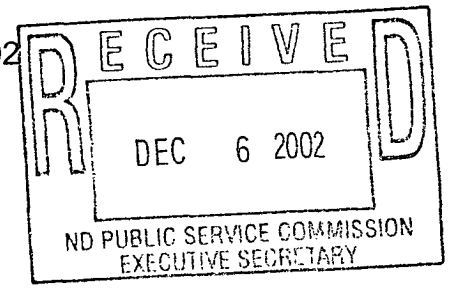
December 6, 2002



Mr. Jon Mielke
Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505-0480

Re: Case No. PU-399-02-183

The purpose of this letter is to outline Montana-Dakota's understanding of the Commission's work session discussions regarding a decision in Montana-Dakota's pending gas rate case, and identify Montana-Dakota's agreement with that understanding.

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., understands from the Commission's work sessions regarding the above case that rather than reaching a decision on the depreciation issue from the current record in the rate case, the Commission desires to consider Montana-Dakota's depreciation rates based on a study to be filed by Montana-Dakota. Montana-Dakota understands that the Commission's order in this case expected to be issued the week of December 9, 2002, will require the filing of a depreciation study by January 31, 2003 with consideration thereof continued as part of the current case. Montana-Dakota recognizes from subsequent discussions with the Commission's advisory staff that the Commission anticipates that the review of the new depreciation study and a decision on the depreciation issue should be complete within six months from the date Montana-Dakota files the new study.

Montana-Dakota further understands that the Commission considers the order to be issued next week to be a final appealable order with respect to all other issues, that the Commission's decisions on these other issues will be reflected in compliance rates to be filed by MDU upon issuance of the order, that the existing depreciation rates will remain in place and be reflected in the compliance rates during the consideration of the study, that the consideration of the study will be conducted as a contested case proceeding based upon the record developed after filing of the depreciation study with all rights of testimony and cross examination, and that any rate changes resulting from the issuance of an order after consideration of the study would be prospective only from the date of such Commission order regarding the study.

Given Montana-Dakota's understanding as noted above, Montana-Dakota would not object to the continuation of the consideration of depreciation based on the new study.

CC: Comm
Legal
Jon
PUD

96 **PU-399-02-183** Pages: 2

Letter re pending gas rate case

by Montana-Dakota Utilities Co., a Division of MDU Re

12/06/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

C. Wayne Fox
President

Scott, Sandi L.

From: Bauske, Shelly A.
Sent: Friday, November 22, 2002 3:31 PM
To: Scott, Sandi L.
Subject: FW: Money Received....

-----Original Message-----
From: **Geiger, Gloria A.**
Sent: Friday, November 22, 2002 3:21 PM
To: Bauske, Shelly A.
Cc: Geiger, Gloria A.
Subject: RE: Money Received....

Gloria Geiger
North Dakota Public Service Commission
600 E Boulevard 13th Floor Dept 408
Bismarck, ND 58505-0480
701-328-2401
fax 701-328-2133
gag@psc.state.nd.us

-----Original Message-----
From: **Bauske, Shelly A.**
Sent: Friday, November 22, 2002 3:18 PM
To: Geiger, Gloria A.
Subject: Money Received....

Case No. PU-399-02-183
MDU
$12,420.00
7700 8503 248 22183

Case No. PU-2780-02-457
Level 3 Communications
$73.26

7700 8503 248 22436

95 **PU-399-02-183** Pages: 0

$12,420.00 received

by Montana-Dakota Utilities Co., a Division of MDU R

11/26/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

12 **PU-2780-02-457** Pages: 0

$73.26

by Level 3 Communications, LLC

11/26/2002 CC: Comm Legal Illona Jerry .

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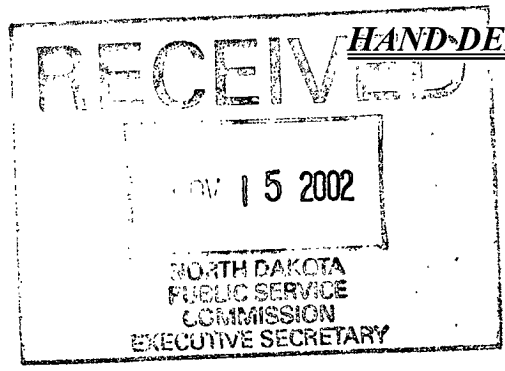
OF COUNSEL
HARRY J. PEARCE

November 15, 2002

HAND-DELIVERED



Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
State Capitol, 12th Floor
Bismarck, ND 58505

RE: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Natural Gas Rate Increase Application
Case No. PU-399-02-183

Dear Mr. Mielke:

Enclosed please find an original and seven copies of the following in regard to the above-captioned matter:

1 BRIEF OF MONTANA-DAKOTA UTILITIES CO.; and
2 FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

I have also enclosed an extra copy to be filed stamped returned with our courier.

Very truly yours,

PEARCE & DURICK

By
William P. Pearce

WPP/leo
Enclosure
cc: Mr. Don Ball - (w/enc.)
Mr. William Binek

94 **PU-399-02-183** Pages: 1

Cover letter re filings

by Montana-Dakota Utilities Co., a Division of MDU R

11/15/2002 CC: Comm Legal Illona, Pat, Jerry Mike

• ALSO LICENSED IN MINNESOTA • ALSO LICENSED IN

STATE OF NORTH DAKOTA

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
NOV 15 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Natural Gas Rate Increase Application

Case No. PU-399-02-183

BRIEF OF MONTANA-DAKOTA UTILITIES CO.

Introduction

The Public Service Commission is entrusted with the responsibility of approving utility rates which are just and reasonable. N.D.C.C. § 49-05-06. This entails approving rates which will provide the utility with the opportunity to earn a rate of return on its property prudently invested in providing service to its customers that is "commensurate with return on investments in other enterprises having corresponding risks" and is "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital." Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944). The evidence presented by the Applicant in this case demonstrates that the rates requested are just and reasonable and are appropriate to generate the level of revenues necessary to accomplish these purposes.

93 PU-399-02-183 Pages: 20
Brief of MDU
by Montana-Dakota Utilities Co , a Division of MDU Re
11/15/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Depreciation Expense

The major issue on the matter of allowable operating expenses pertains to the proper depreciation rates to be employed to determine the projected 2003 test year depreciation expense. The evidence presented by Montana-Dakota shows that the 2003 depreciation expense is $3,261,000 [Ex. 2, Statement N, p. 15]. This was determined on the basis of the depreciation rates developed in a detailed full depreciation study performed for the Company by Stone & Webster Management Consultants, Inc. in 1992 and accepted by this Commission in previous cases.

The Commission Staff witness Michael Majoros, however, asserted that those rates, despite having been previously accepted by this Commission, result in "excessive" depreciation, on the claimed grounds that negative net salvage was too high and the lives of mains and services were too short [Ex. 19, p. 10]. His conclusion was that the 2003 depreciation expense should be only $1,089,000. [Ex. 19. MJM-7, p. 3]. The difference of $2,172,000 between this amount and the Company's 2003 depreciation expense of $3,261,000 accounts for most of the discrepancy between the Company and Staff positions on revenue requirements.

Whereas the Company's computation of depreciation expense is based on the Stone & Webster depreciation study, the Staff's position is based not on any kind of study but rather simply on the following unsupported conclusory opinions:

(1) Mr. Majoros' unsupported opinion was that "based on my experience ... the depreciation reserves are extraordinarily high" [Ex. 19, p. 9]. He offered nothing to show what that "experience" was, nor what "extraordinarily high"meant, except the unsupported assertion that "the cost of removal factor in Account 380-Services is extremely high. ... On its face this [140 per cent negative salvage] appears to be very excessive." [Ex. 19, p. 9]

(2) Based again simply "on my experience" and investigation of gas depreciation rates "on several occasions," Mr. Majoros asserted that the lives for Accounts 376-Mains and 380-Services used in the Stone & Webster depreciation study are "extremely short." [Ex. 19. p. 10]. His conclusion was that instead of fairly normal service lives of 36 and 34 years, respectively, mains and services should have extremely long lives of 108 and 69 years instead, leading to lower annual depreciation expenses.

(3) Mr. Majoros contended that the negative net salvage shown by the Company was incorrect and that positive salvage has been experienced during the past five years, and speculated that the Company had not recorded any net salvage at all for services. [Ex. 19, p. 11-12].

In fact, however, as the Company's testimony demonstrated, net salvage for services is recorded, and negative net salvage has been the normal situation. [Tr. p. 316; Ex. 30]. Mr. Majoros's conclusion that positive net salvage was the normal situation was based on misconceptions resulting from looking at isolated items over a short term. As explained by Company witness Craig Keller, positive net salvage almost always results from one of three things: (1) the sale of an asset, (2) receipt of insurance proceeds, or (3) the trade in of an asset for a different asset. [Tr., p. 387].

All three of these factors are applicable to this case:

(1) Sale of an Asset. For the period in question examined by Mr. Majoros there was a sale of a substantial asset, the Schuchart Building in Bismarck, sold by the Company at book value to an affiliate. There was therefore no actual gain, although the sale proceeds show up for accounting purposes as a large amount of positive net salvage. What the Company actually did, of course, by this transaction was simply to collect its cost for the building. The offsetting adjustment in the

depreciation reserve for the retirement of this asset creates "positive" net salvage, as Mr Keller explained. As Mr. Jeter pointed out:

> "I want to make sure everybody understands there was not a gain on the sale. There was nothing that the customers are ever going to realize. This building was sold for its net cost. In other words, its original cost less the depreciation that had been accumulated on it from the time that it was placed in service." [Tr., p. 313]

(2) Receipt of Insurance Proceeds. The Company received substantial insurance proceeds for damage resulting from the severe June 2001 hailstorm in the Bismarck-Mandan area, and the surplus from the proceeds was credited to reserve salvage, which is a direct benefit to ratepayers. [Tr. p. 388].

(3) Trade-ins. The Company has a program by which it trades in equipment every other year, allowing it to acquire new equipment at little cost. As Mr. Keller pointed out, this appears as positive salvage on the one hand but is balanced and offset by the new property addition on the other hand: "There's really no net increase in plant because of those transactions. It just shows up as salvage." [Tr., p. 389].

Therefore Mr. Majoros' conclusion that Montana-Dakota normally experiences substantial net positive salvage is simply based on an erroneous interpretation of data applicable to a certain limited period or years in which extraordinary events occurred. The fatal defect in the Staff's position on depreciation is that all of Mr. Majoros' conclusions are based simply on the unsupported assertion that depreciation reserves were excessive, that net salvage was allegedly positive rather than negative, that service lives were too short, etc .

The fundamental basis of depreciation accounting is, of course, quite straightforward:

> "Depreciation is an expense which represents an allocation of the cost of utility plant over the periods that benefit from the plant's use in providing utility service. ...

> The allowance for any given year is but one step in a systematic and gradual transfer of capital costs into a series of charges to current operations during the estimated useful lives of the depreciable fixed assets. In this way, the attempt is made to apportion the costs of the assets among the years during which they perform service instead of charging them in lumps either to the year of acquisition or to the year of retirement, Thus the cost of a depreciable fixed asset is treated as a prepaid expense, to be amortized through a series of subsequent charges against current revenues." Bonbright, *Principles of Public Utility Rates* (1988), p. 271, 273

It is essential that the methodology of amortization of costs through the allowance for depreciation expenses "in addition to being systematic, must also be rational." *Id.* at p. 274. In this case there is a detailed depreciation study in place which has not been supplanted by any subsequent depreciation study. Mr Majoros does not contend that he has actually done a depreciation study of any kind comparable to the 1991 Stone & Webster study. He simply picked out a few isolated items from a limited time period which he considered "excessive" or unreasonable and eliminated a large part of the 2003 depreciation expense on that basis. As the Company's depreciation expert John Jeter, stated:

> "A proper depreciation study would involve reviewing additions, retirements, transfers, salvage, removal costs, and accumulated depreciation for the entire history of each account in gas plant and common plant for Montana-Dakota's gas distributions operations, none of which Mr. Majoros did." [Tr., p. 283] (emphasis added)

The existing Stone & Webster depreciation study provides the best evidence, and in fact the only real substantive evidence, for the proper depreciation rates to be used for this specific company. "Whether observed physical depreciation or book reserve depreciation or some other indicator is used, there must be substantial evidence that it accurately aids in determining value." Southern Union Gas Co. v. New Mexico Public Service Commission, 503 P.2d 310, 312 (N.M. 1972). There is no such evidence in the record in this case to support the Staff's position on depreciation expense.

The standard technique for obtaining such evidence of the appropriate depreciation expense is to conduct exactly the kind of thorough depreciation study that Stone & Webster did in 1991:

> "The purpose of a depreciation study is to determine the service lives of a utility's equipment, and the corresponding yearly depreciation cost of that equipment." Appeal of the Office of the Consumer Advocate, 597 A.2d 528, 597 A.2d 528 (N.H. 1991)

An actual depreciation study like the Stone & Webster study, based on the actual experience of the Company, will result in accurate and reasonable results, as opposed to simply applying a general mathematical technique as Mr. Majoros did. As the court pointed out in City of Cincinnati v. Public Utilities Commission, 86 N.E.2d 10, 34-5 (Ohio 1949):

> The city's composite percentage of annual depreciation in the amount of 1.25% would be based on an over-all life of the entire property of the company of 80 years. This is rather an absurd average life basis when we take into consideration that a great deal of the property involved is production equipment, meters, services, furniture and fixtures, all of which have a very much shorter average life span."

In the absence of a new detailed depreciation study,[1] there is simply no rational basis for abandoning the existing study by arbitrarily adjusting individual components as advocated by the Staff. In Shevin v. Yarborough, 274 So.2d 505, 512 (Fla. 1973), for example, the court found no basis had been shown for abandoning an existing depreciation rate that had been approved in prior proceedings:

> "However, the Company is using a 3.30% rate by direction of this Commission. ... While the Company needs to get its depreciation 'housekeeping' in order and we expect them to do just that, the purpose of this proceeding is not to establish depreciation rates, but to measure the reasonableness of the Company's earnings under existing rates approved or ordered by this Commission. We find no reasonable basis for adjusting to a 3% composite depreciation rate for the test year 1970 when the Company was at that time obeying an Order of this Commission requiring it to

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[1] As the record shows, such a new depreciation study, commissioned by the Company, is now underway.

charge a rate of 3.30%."

That is precisely the case here, and the courts have regularly approved the use of the results of the pre-existing depreciation studies. *E.g.*, Scranton Steam Heat Co. v. Pennsylvania Public Utility Commission, 167 A.2d 693 (Pa. Sup. 1960) [approving the use of depreciation rates based on prior engineering studies]. In United Water Delaware, Inc. v. Public Service Commission of Delaware 1998 Del. Sup. 1, 28 [Lexis 122], the court found the evidence presented in support for changing depreciation rates from the existing ones to be insufficient for the same reasons that the Staff's evidence in this case is insufficient:

> "Substantial evidence supports the Commission's decision to maintain the current depreciation rates. ... Based on the record, the Commission properly found that United Water did not satisfy its burden of proof, because its study was less than accurate, based on an incomplete asset examination, and not supported by sufficient evidence" (emphasis added)

The fact that there is an existing depreciation study which provides the best evidence for the appropriate depreciation rates works in both directions, of course. If the Company were now arguing for higher depreciation rates than those in the study, it should not prevail in the absence of some kind of highly probative and convincing evidence that the study had been flawed. In Litchfield Park Service Co. v. Arizona Corporation Commission, 874 P.2d 988, 996 (Ariz. 1994), for example, the utility argued for a higher depreciation allowance but had no new depreciation study to support its case. The court upheld the Commission in denying any increase:

> "The Commission concluded that, in the absence of an account-by-account depreciation study, it would keep in effect for both divisions the three percent rate.... As to the propriety of the three percent rate of depreciation for the sewer division, the Commission's decision is supported by the record... [the company] has failed to show clearly and convincingly that this rate is unlawful or unreasonable."

Cost of Capital

The testimony of Montana-Dakota's expert witness Dr. J. Stephen Gaske showed that the weighted cost of capital, that is the allowed rate of return on the rate base which should be approved in this proceeding, is 11.044%. The weighted cost of capital includes the usual elements of equity capital, long-term debt and preferred stock. There is no dispute in this matter as to the 4.63% cost of Montana-Dakota's preferred stock, which accounts for 5.23% of the capital structure.

Debt Capital

The Company's undisputed testimony established that the cost of the Company's $132,600,000 in long-term debt capital, as of the 2003 projected test year, is 9.180%. [Ex 2, Statement F, Sch. F-1, p. 3]. The Staff's expert Charles King advocated the inclusion of short-term debt in Montana-Dakota's capital structure, arguing that short-term debt is used to finance materials and supplies, fuel stocks and prepayments. The Company's Controller and Chief Accounting Officer, Craig Keller, however, explained that materials and supplies, fuel stocks and prepayments, although classified on the balance sheet as short-term assets, are in fact used to support the long-lived assets, such as plant, property, equipment and related items, and that accordingly Montana-Dakota finances long-term assets with long-term debt. It is fundamental that the debt portion of the capital structure of a utility for ratemaking purposes is comprised of the long-term debt. Bonbright, *supra*, at p. 307. There is therefore no basis, either in theory or in the facts in this case, for the inclusion of short-term debt in the capital structure of Montana-Dakota.

Mr. King also advocated that the debt of Centennial Energy Holdings, Inc. [Centennial] should be taken into account when calculating the debt costs of Montana-Dakota, on the grounds that both Centennial and Montana-Dakota are subsidiaries of a common parent corporation, MDU

Resources Group, Inc. [MDU Resources]. The utility company Montana-Dakota, however, is not a separate legal entity. It is simply a division of MDU Resources. The debt capital to which Montana-Dakota has access is the debt capital of MDU Resources, as Mr. Keller explained. [Tr. p. 129-30]. He discussed in some detail how, and why the debt capital of MDU Resources is not available to Centennial and its subsidiaries:

> "Yesterday King made a statement that MDU was attempting to build, quote, a firewall around MDU to separate the debt of Centennial from MDU. And that is exactly what MDU is trying to do. And I'd like to explain to you the reasons for this and why I believe the Commission should support MDU in its efforts. ... The concern is that bad decisions made at Centennial Energy or one of its subsidiary companies could cause default or cause a bankruptcy that could roll up into Montana-Dakota or MDU. And what we're trying to do is prevent this from happening. ... [W]hat we're trying to do is protect the assets and the customers of MDU from our nonregulated businesses. And the concern we have is ...we do not want them [creditors of Centennial or its subsidiaries] to have access to the assets of the utility. We want to protect our customers from this happening. And there's some things we can do. And one of them is we need to keep separate and distinct books from Centennial, which we currently do. We need to conduct the business of the utility in a manner that is clearly distinguishable and separate from the operations of Centennial, and we do that. MDU does not participate in a money pool or comparable intercompany fund arrangement with Centennial or its subsidiaries. This means that MDU does not commingle its corporate funds with those of Centennial. It means that MDU and Centennial maintain their own distinct and separate credit facilities. Neither have access to the other's credit agreements. To further strengthen this point, MDU does not lend funds or otherwise extend credit to Centennial, and Centennial does not do the same back to MDU." [Tr. p . 380-82]

A first mortgage lien on MDU Resources' gas and electric property is what is used to secure the long-term debt financing. The only property that can be pledged under the mortgage indenture is qualifying utility property, and Centennial cannot mortgage its non-regulated assets under the indenture and has no access to the capital raised under the indenture. [Tr. p. 382]. Centennial must raise its own capital apart from the utility property of MDU Resources, and in fact Centennial is not

allowed even to use MDU Resources's name in its financing arrangements. [Tr. p. 383].

It is clear, therefore, that Montana-Dakota has no access to any of the debt of Centennial or its subsidiaries, under the terms of the Centennial debt covenant. The Centennial debt covenant governs the unsecured debt of Centennial and its subsidiaries and does not pertain to, and cannot be accessed or utilized by, the utility company. It is wholly improper, therefore, and would materially distort the determination of the cost of the Company's capital to include any of the Centennial debt or equity in calculating the cost of debt or capital structure for Montana-Dakota. The uncontroverted evidence in the record established that the actual projected cost of debt capital for Montana-Dakota for the 2003 test year is 9.180%.

Equity Capital

Dr. Gaske testified that the appropriate cost of equity capital is 13.25% [Ex. 4, p. 34], whereas Mr. King's testimony was that the appropriate rate is 10.5%. [Ex. 15, p. 2]. The primary points of difference between these two figures arise from the use of a flotation cost adjustment by Dr. Gaske, the determination of growth rates , assessment of comparable risk and the selection of comparable companies

Flotation Cost Adjustment

The basis for allowing a rate of return on equity capital, often referred to as the cost of equity capital, is that a utility company should be in a position to be able to raise equity capital by issuing common stock at any time. The generally accepted method for determining the proper cost of equity capital is the DCF (discounted cash flow) analysis employed by the expert witnesses for both Montana-Dakota and the Staff. That method is based on the premise that the stock price must be

sufficiently above book value that stock can be issued without diluting the value of existing shareholders' investments, and this requires the inclusion of an allowance for the " flotation cost," that is the cost associated with issuing stock (underwriting commissions, filing fees, etc.) that reduce the net proceeds of issuance below the total amount actually received. For example, this means that if the proceeds of an issue are 91 percent of market price, the commission should maintain market price at about 110 percent of book value (*i.e.* 1/91%). The objection raised by Mr. King that the company may not have recently raised equity capital is irrelevant, since the point is that whether the utility is actually in the process of issuing new common stock, or is planning an imminent offering of common stock, the utility must always be able to be in the position to do so:

> "This fundamental requirement of a fair rate of return is analogous to a well-understood principle that a firm, or an individual, should maintain a good credit rating even then they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue common stock several years in advance, it should be in the position to do so on reasonable terms at all times without dilution of the book value of the existing investors'common equity." [Ex. 4, p. 13]

This goal can only be achieved if the flotation cost adjustment is applied to the entire rate of return, and the appropriate adjustment, as testified by Dr. Gaske, is approximately 4.75 percent. The average of a representative sample of flotation costs incurred with 34 new common stock issues by natural gas transmission and distribution companies between 1992 and 2001 was 4.85%, confirming the 4.75 percent figure. [Ex. 4, JSG -2, Sch. 3]. A rate of return which does not include the flotation cost adjustment is necessarily inadequate

Comparable Companies

The group of comparable companies used by Dr. Gaske in his DCF analysis is the Moody's

gas distribution group, which is commonly used as a comparison group of companies that are representative of the gas distribution industry. [Tr., p. 429]. The Staff expert witness Mr. King has previously used the same group of comparison companies in testimony before this Commission but on this occasion he used a different group, consisting of companies that derive at least 75% of their revenues from gas distribution operations, except that he also included WGL Holdings, which does not meet this criterion. [Tr., p. 430]. As would be anticipated, many of the comparison companies used by both witnesses are the same, and only a small part of the difference between the results of the DCF studies carried out by both are accounted for by the differences in the selection of comparison companies. It is submitted, however, that Dr. Gaske's selection is more rational and is more likely to lead to a realistic result than Mr. King's which incorporates one company that does not meet his own selection criteria.

Comparable Risk

Dr. Gaske pointed out that Montana-Dakota has about average risk, or slightly above average risk, when financial risk (*i.e.* capital structure) and business risk (*i.e.* competition, small size, slow customer growth, etc.) are considered in the aggregate. He noted that his risk assessment for the Company is confirmed by the fact that MDU's first mortgage bonds have a somewhat lower than the average rating for the Moody's gas distribution group. [Tr., p. 448; Ex. 36]. Mr King asserted that Montana-Dakota is a relatively low-risk operation because it is a part of a much larger parent company, MDU Resources Group, Inc., but at the same time he alleged that one of the reasons for the Company's low risk is that only the gas distribution operations are in question in this proceeding, *i.e.* 100% of the operations. In fact, however, the contrary is true, that is Montana-Dakota's business risk for its gas distribution business is higher than that of a larger company like

Mr.King's comparison company Southwest Gas. As Dr. Gaske pointed out,

> "... he [Mr. King] says, for example, Southwest Gas may be actually less risky because it's growing rapidly. Well, in Montana-Dakota's service territory there's little or no growth at all and, in fact, if you look behind what's going on a little bit, they have a customer growth of about 1 percent per year, but a lot of that is people moving out of small towns to the larger cities. So you have a situation where they're needing to expand facilities in the city, but they still have costs that they have to recover in the smaller towns that [are experiencing] declining population. And in the long run that's a problem for the company. ... Mr. King indicated that a fast growing company like Southwest Gas has low risk. ... If you look at Montana-Dakota, it's at the other end of the spectrum."" [Tr., p. 449]

Operating and Maintenance Expenses

Supplemental Income Security Plan

Montana-Dakota introduced evidence showing that the portion of the annual cost of its Supplemental Income Security Plan (SISP) allocable to North Dakota gas operations is $265,000. [Ex. 2, Statement N, p. 8]. The SISP is a supplemental pension benefit designed to attract and retain key employees. These kinds of programs, which have in the last few years become commonplace in the utility industry as part of the overall compensation package due to changes in federal regulations pertaining to retirement benefits and Social Security benefits, are essential "to attract and retain employees in key positions." [Ex. 7, p. 3]. Mr. Espeland summarized the philosophy behind the SISP:

> "We can deliver $1,000 in a lot of different ways. We choose to offer base salary. We choose to have incentive pay so it's not a fixed cost, but it's only given if performance is there. And we choose to have benefits and other programs [like SISP] that provide for economic security. It's the most cost-effective way of doing – delivering value to the executives and to the employees at all levels. And we could easily pay them all in base salary, all in base rate. It would not be the most cost-effective or the most incentivizing for good customer service." [Tr., p. 530]

For these reasons, although this Commission chose not to do allow the SISP costs in Case No. PU-399- 01-186 earlier this year, the Company urges the Commission now to recognize the importance of programs like SISP and acknowledge that they operate to benefit the ratepayer and accordingly are just and proper operating expenses prudently incurred by the Company in providing reliable service at reasonable rates.

Labor Expense

The adjustment made by Montana-Dakota to 2001 labor costs to determine budgeted 2002 labor costs, amounting to a 3.15% increase for 2002, and the projection of 2003 labor expense by applying a 3% increase to 2002 levels, is commensurate with industry practice and experience. The undisputed evidence presented by the Company demonstrates, in fact, that such levels of annual upward labor adjustments are somewhat less than is prevalent in the present labor market. [Ex. 27, p. 4-6]. As the Company's witness Richard Spratt pointed out:

> "In an effort to provide competitive rates to our customers, Montana-Dakota has, for many years, managed its operations as economically as possible, to the point of providing very conservative wage adjustments for employees. This method of management has resulted in lower wage rates offered our employees as compared to those offered by our competition." [Ex. 27, p. 5]

Executive compensation is about 11% below, and office employee compensation is about 9% below, current industry levels. [Ex. 27, p. 5]. The Company's labor costs projected for the test year 2003 are appropriate and reasonable.

The Company testified that base pay, bonus (incentive) pay, employee benefits and the work environment are all important components of the total compensation package provided for Montana-Dakota employees. [Ex. 27, p. 2-8]. The labor costs discussed above include the projected employee bonuses, based on a three-year average of bonuses. Such bonus and incentive plans are wide-spread

through the utility industry as a means for attracting and retaining highly qualified employees. Since the availability of employee performance-based bonuses is an important and reasonable means for attracting and retaining qualified employees, it is a substantial benefit to customers.

Other Operating and Maintenance Expenses

Mr. Majoros recommendation that the operating and maintenance expenses ("other expenses") that were not specifically adjusted in the Company's testimony should be left at 2001 levels is unreasonable and unrealistic. He contended that an increase from the 2001 level of $3,689,000 to the projected 2003 test year level of $3,898,000, amounting to a 5.7% increase over two years, had not been allowed in previous cases and he saw no reason to begin now. The fact, however, is that inflation does occur and will continue to do so. No basis was offered, and none exists, for artificially holding those expenses constant over a two-year period, when in fact actual inflation continues to occur. As the Company's witness Rita Mulkern pointed out, "It is time to recognize that these costs [the "other costs" not specifically adjusted by the Company] are subject to inflationary pressures just as the other identified items have been." [Ex. 25, p. 3]. The increase from 2001 to projected 2002 is only 2.81%, and the increase from projected 2002 to projected 2003 is only another 2.81%, commensurate with the current general annual levels of inflation in every sector of the economy.

Implementation of Financial Accounting Standard No. 143

A recently promulgated Financial Accounting Standard, "Accounting for Asset Retirement Obligations" [FAS 143] is designed to require businesses to accrue for the expected retirement cost of an asset over the period of the asset's useful life through increased depreciation with higher cost

pushed toward the retirement date of an asset due to the discounting methods used, rather than using levelized depreciation as this Commission and other regulatory bodies have traditionally done. There has been considerable concern nationwide concerning the implementation of FAS 143, which is complex and will be administratively burdensome. This new standard is untested at this point and there is considerable debate as to how, when and in what manner it should be implemented for ratemaking purposes. This is not a matter which should, or reasonably can be, addressed in an ancillary manner in this rate case involving a single utility company operating in North Dakota. These complex questions, which affect all utilities and their customers, can only be properly addressed and thoroughly examined in detail in a generic rulemaking proceeding by this Commission in which all companies involved in utility operations in this state may participate and present their views on the question.

The testimony in this case shows that while FAS 143 must and will be implemented by the Company for financial reporting purposes, it is not necessary to implement the new standard immediately for regulatory and ratemaking purposes. A specific Financial Accounting Standard (FAS 71) ("Accounting for the Effects of Certain Types of Regulation") is available to provide the methodology by which utility companies can account for the differences between depreciation accounting under FAS 143 and more traditional regulatory accounting, during the period of time required to carefully study FAS 143 in the context of ratemaking purposes, so that it can be implemented in a manner that will accommodate the interests of all affected parties.

The Company requested at the opening of this case, and reiterates that request now, that the Commission refrain from requiring implementation of FAS 143 for ratemaking purposes until the matter can be studied in detail in a specific generic proceeding in which all affected utility companies

operating in North Dakota are made parties and have the opportunity for input. Only in this way, can the complex issues raised by FAS 143 in the ratemaking context be properly understood and handled. As Mr. Keller pointed out, the industry associations "are recommending a go-slow approach on FAS 143 implementation for ratemaking" [Tr., p. 386]. For these reasons, this is certainly the most appropriate manner in which to deal with the question.

Rate Design

The most widely-accepted measure of the reasonableness of utility rates for any given class of customers is the cost of service. Bonbright, *supra,* p. 389. The proposed changes in Montana-Dakota's rate design are specifically designed to more accurately reflect the various components of the cost of serving its gas distribution customers. The Company based its distribution of its total revenue requirement among the various customer classes and the pricing of the components comprising the total rate applicable to each customer class on its class cost of service study [Ex. 2, Statement M]. The primary difference between the Company's cost of service study and the cost of service study presented by Mr. King results from a difference in the allocation of the investment in distribution mains among the various rate classes. The Company's allocation of distribution mains on the basis of customers and peak day demand will more accurately reflect the elements creating the costs of service than Mr. King's allocation based on energy and peak day demand. Accordingly, it will better promote the ratemaking goal of matching rates to costs of service.

The Company's rate design proposal also includes a change in the rate structure to more accurately reflect these costs of service. The customer gas bill would be composed of three elements: (1) Basic Service Charge, (2) Distribution Delivery Charge, and (3) Cost of Gas. The

Basic Service Charge would be set at or nearly at the customer cost level for each rate class. The Basic Service Charge is reflected in the existing rate structure as the "base rate," but the level of the current base rate substantially under-recovers the actual customer cost, so that a portion of the actual customer cost is shifted to, and recovered through volumetric charges.

The Distribution Delivery Charge reflects demand and energy-related costs, as well as any customer costs not recovered in the Basic Service Charge. This portion of the rate is a flat commodity charge, and implementation of this proposal would allow the declining block rate now applicable to residential and firm general service customers to be eliminated, since the customer related costs previously collected in the initial block of the rate will be recovered instead through the Basic Service Charge. The proposed rate structure will provide relief to customers during the winter months when their heating requirements result in higher gas usage, by lowering the amounts collected on the basis of the volume of gas used. The Cost of Gas component reflects all cost of gas items which the Company passes through to its customers under the purchased gas adjustment clause.

The proposed rate structure will promote rate stability and will have the beneficial effect of allowing gas customers to better understand the basis of their bills and will promote the general underlying goal of utility rate design to attempt to match the charges to the actual cost of providing gas service to each customer, thereby eliminating, or at least minimizing, cross-subsidization among and within customer classes. All of these goals are among the "attributes of a sound rate structure, as outlined by Professor Bonbright, which include (1) "revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility customers," (2) efficiency of the rate classes and rate blocks, in discouraging wasteful use of service while promoting all justified types

and amounts of use," (3) "fairness of the specific rates in the apportionment of total cost of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity," (4) "avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (*i.e.* subsidy free with no intercustomer burdens," and (5) the related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptance, and feasibility of application." Bonbright, *supra*, p. 383-84.

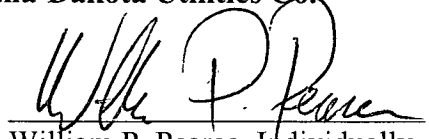
While the Company's proposed rate structure results in an increase for the residential and firm general service customers, with no increase for the Air Force and large interruptible classes, and a decrease for small interruptible customers, this is based on an appropriate matching of rates to cost of service, and the furthering of the goals described above. The Company's proposed rate structure therefore provides for a basis of charges to its customers that is just and reasonable without undue discrimination.

CONCLUSION

The preponderance of the evidence in the record demonstrates that the Company's application for increased rates is appropriate and that the proposed rates and rate structure will allow the Company the opportunity to earn a reasonable rate of return without discrimination among customer classes.

Dated November 15, 2002.

Montana-Dakota Utilities Co.

By 

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STATE OF NORTH DAKOTA

BEFORE THE PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Natural Gas Rate Increase Application

Case No. PU-399-02-183

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

November____, 2002

Preliminary Statement

On April 12, 2002, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. [hereinafter Montana-Dakota] filed an application to increase its rates for natural gas service in an amount sufficient to generate increased total annual revenues of $2,844,132. The application of Montana-Dakota stated that the existing rates, which were approved by the Commission in 1994, are unjust, unreasonable and not compensatory, and that said rates must be increased so that Montana-Dakota may have the opportunity to earn a just and reasonable rate of return on its natural gas properties devoted to providing service to its North Dakota natural gas customers.

On June 5, 2002, the Commission issued a Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline, setting the public hearing in this matter for October 7, 2002, and scheduling informal public input sessions via interactive television on July 15, 2002, in Bismarck, Dickinson, Williston, Minot, Jamestown and Devils Lake. The public input sessions

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Proposed Findings of Fact, Conclusions of Law and Order
by Montana-Dakota Utilities Co., a Division of MDU R

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were held at said time and places, and several members of the public made appearances.

On August 9, 2002, Montana-Dakota filed an application seeking a protective order pertaining to the disclosure of certain trade secret information sought in data requests made by the Commission Staff. The Staff did not contest the application for trade secret protection, and the Commission entered an order granting the application on August 28, 2002.

Pursuant to the Notice of Hearing, the Commission held the public hearing at the State Capitol in Bismarck on October 7-8, 2002, on the following issues:

1. What is the value of Montana-Dakota's property, used and useful for the service and convenience of the public in providing natural gas service in North Dakota?

2. What is Montana-Dakota's rate of return on its natural gas property, used and useful for the service and convenience of the public in providing natural gas service in North Dakota?

3. What is a just and reasonable rate of return on Montana-Dakota's property, used and useful for the service and convenience of the public in providing natural gas service in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on Montana-Dakota's property, used and useful for the service and convenience of the public in providing natural gas service in North Dakota?

5. Are Montana-Dakota's rate schedules designed in such a manner that they will result in a basis of charge to its customers that is just and reasonable without discrimination?

No person intervened or sought intervention in this matter and no members of the public appeared at the public hearing.

Ths Commission, having reviewed the evidence in the record, makes the following:

FINDINGS OF FACT

Jurisdiction

1. Montana-Dakota is a division of MDU Resources Group, Inc. and is a public utility providing natural gas distribution services to approximately 83,500 customers in 76 communities in North Dakota. The customer mix is approximately 86.5 percent residential, 13.3 percent firm commercial and 0.2 percent small and large interruptible customers. The residential, firm commercial and small interruptible customers use natural gas primarily for space and water heating.

2. The rate changes in question in this proceeding do not affect the cost of purchased gas distributed by Montana-Dakota, which is separately recovered through the purchased gas adjustment provisions contained in Montana-Dakota's filed tariffs and previously approved by the Commission.

Test Year

3. The appropriate test year to be used for determining Montana-Dakota's rates in this this proceeding is 2003, the test year selected by the Company pursuant to N.D.C .C. § 49-05-04.1.

Rate Base

4. Based upon the evidence received at the public hearing, the appropriate 2003 average rate base for Montana-Dakota's North Dakota natural gas service is $19,681,000, determined as follows:

	(Thousands)		
Description	2001	2002 (Projected)	2003 (Projected) [Test Year]
Plant in Service	$68,787	$70,446	$72,793
Less: Accumulated Reserve for Depreciation	$44,629	$47,021	$49,356
Plus: Construction Work in Progress	$167		
Net Plant in Service	$24,325	$23,425	$23,437
Materials and Supplies	$402	$439	$439
Fuel Stock	$21	$22	$22
Prepayments	$19	$84	$84
Other	$151	$97	$44
Total Additions	$593	$642	$589
Accumulated Deferred Income Taxes	($4,297)	($4,090)	($3,842)
Accumulated Deferred Investment Tax Credits	($290)	$256	($231)
Customer Advances	($377)	$272	($272)
Total Deductions	($4,964)	($4,618)	($4,345)
Rate Base	**$19,954**	**$19,449**	**$19,681**

Cost of Capital

5. The Commission finds that the appropriate year to be used for the determination of the capital structure and cost of capital for Montana-Dakota is the test year 2003.

6. Montana-Dakota's present capital structure consists of long-term debt, preferred stock and common stock (common equity). The Commission finds that the projected 2003 test year capital structure consists of 43.039% long-term debt, 5.274% preferred stock and 51.687% common equity,

and that said capital structure is appropriate and reasonable for the determination of rates herein.

7. The cost rate of Montana-Dakota's $16,250,000 in preferred stock was not disputed in this proceeding, and the Commission finds that it is 4.622%.

8. Expert testimony on behalf of the Staff and on behalf of Montana-Dakota was presented pertaining to the determination of the cost of the Company's $133,500,000 in long-term debt capital. The Staff's expert King advocated the inclusion of short-term debt in Montana-Dakota's capital structure, arguing that short-term debt is used to finance materials and supplies, fuel stocks and prepayments. Montana-Dakota's witness Keller, however, testified that materials and supplies, fuel stocks and prepayments, although classified on the balance sheet as short-term assets, are in fact used to support the long-lived assets, such as plant, property, equipment and related items, and that accordingly these items are financed with long-term debt. The Commission accordingly finds that short-term debt should not be included in the capital structure of Montana-Dakota.

9. Mr. King also advocated that the debt of Centennial Energy Holdings, Inc. [Centennial] should be taken into account when calculating the debt costs of Montana-Dakota, on the grounds that both Centennial and Montana-Dakota are subsidiaries of a common parent corporation, MDU Resources Group, Inc. The evidence presented by the Company however, demonstrated that Montana-Dakota has no access to any of the debt of Centennial or its subsidiaries, under the terms of the Centennial debt covenant. The Centennial debt covenant governs the unsecured debt of Centennial and its subsidiaries and does not pertain to, and cannot be accessed or utilized by the utility company. The Commission finds that it would be improper to include any of the Centennial debt or equity in calculating the cost of debt or capital structure for Montana-Dakota. Accordingly, the Commission finds the appropriate cost of debt capital for Montana-Dakota to be

9.180%, as testified to by the Company.

10. Expert testimony on behalf of the Staff and on behalf of Montana-Dakota was presented pertaining to the determination of the cost of Montana-Dakota's $159,245,775 in equity capital. The required rate of return on common equity must be set so as to ensure that the return is adequate to attract capital and is commensurate with returns available on other alternative investments having similar levels of risk. The Commission finds, based on analysis of business, regulatory, financial and market risks faced by comparable gas distribution companies, and upon recognizing that it is appropriate to include the 4.75% flotation cost adjustment testified to by Montana-Dakota's expert witness Dr. J. Stephen Gaske, that the appropriate cost of equity capital for Montana-Dakota for its gas distributions operations for the test year 2003 is 13.250%.

11. Accordingly, the Commission finds that the overall rate of return on rate base which should be allowed for Montana-Dakota in this proceeding is 11.044%, determined as follows:

Source of Capital	Capital Ratio	Cost Rate	Overall Rate of Return
Long-term Debt	43.039%	9.180%	3.951%
Preferred Stock	5.274%	4.622%	0.244%
Common Equity	51.687%	13.250%	6.849%
TOTAL	**100.000%**		**11.044%**

12. In order to achieve this rate of return Montana-Dakota requires additional natural gas revenues in the amount of $2,844,132.

Sales and Transportation Volumes

13. The Commission finds that the test year 2003 projected gas sales and transportation

volumes for all customer classes, as set forth in the Company's Statement N (contained in Exhibit 2) are reasonable and they are adopted for purposes of determination of just and reasonable rates.

Operating and Maintenance Expenses

Labor Expense

14. The adjustment made by Montana-Dakota to 2001 labor costs to determine budgeted 2002 labor costs, amounting to a 3.15% increase for 2002, and the projection of 2003 labor expense by applying a 3% increase to 2002 levels, was shown to be commensurate with industry practice and experience. In fact the evidence showed that such levels of annual upward labor adjustments are somewhat less than is prevalent in the present labor market. The Commission accordingly finds the labor costs projected for the test year 2003 to be appropriate and reasonable.

Bonus

15. The Company testified that base pay, bonus (incentive) pay and employee benefits are all important components of the total compensation package provided for Montana-Dakota employees. The labor costs in Finding No. 14 above include the projected employee bonuses, based on a three-year average of bonuses. The evidence showed that such bonus and incentive plans are wide-spread through the utility industry as a means for attracting and retaining highly qualified employees. The Commission specifically finds that the availability of employee performance-based bonuses is an important and reasonable means for attracting and retaining qualified employees, and that this will be a benefit to customers.

Pension and Post-Retirement Benefits

16. Montana-Dakota introduced evidence showing that its pension and post-retirement

benefit costs will increase substantially in 2003, in an amount of $240,000 applicable to North Dakota operations ($150,000 in pension expense and $90,000 in post-retirement expense), due to the decline in asset returns from the abnormally high returns received in recent years and the decline in discount rates to reflect current long-term interest rates, both of which result in increased pension and benefit costs. The Commission finds this adjustment to be appropriate and accordingly allows this item of $240,000 as an operating expense increase over the projected 2002 levels.

17. Montana-Dakota introduced evidence showing that the portion of the annual cost of its Supplemental Income Security Program (SISP) allocable to North Dakota gas operations is $265,000. The SISP program is a supplemental pension benefit designed to attract and retain key employees. The Commission declined to allow this as a recoverable operating expense in Case No. PU-399-01-186, decided on April 24, 2002. The Company has reargued its position in the present case and demonstrated that such plans are common in the industry and that the SISP program is beneficial to Montana-Dakota customers and serves the public interest by helping to insure high-quality management of the Company. Accordingly, the Commission has determined this adjustment to be appropriate and allows this item of $265,000 as an operating expense.

Medical and Dental Expense

18. The Company's testimony shows that expenses for medical/dental coverage will increase to $1,003,000 for 2003, and this was not disputed by the Staff. The Commission finds this to be an appropriate level for this element of operating expenses.

Rate Case Expense Amortization

19. The Commission Staff witness Michael Majoros advocated the amortization of rate case expense over a five-year period, rather than the three-year period used by the Company, on the

grounds that the Company had not filed a general gas rate increase application for a number of years. The Company, however, testified that it would be unlikely that future applications would be as infrequent, in view of the fact that it has achieved most of the economies and cost savings that are feasible, so that general inflation will tend to drive the future frequency of rate applications. The Commission finds that a three-year amortization is appropriate and reasonable in the circumstances.

Inflation Adjustment for Other Operation and Maintenance Expenses

20. The Staff witness Majoros recommended that the operating and maintenance expenses ("other expenses") that were not specifically adjusted in the Company's testimony should be left at 2001 levels, arguing that an increase from the 2001 level of $3,689,000 to the projected 2003 test year level of $3,898,000, amounting to a 5.7% increase over two years, was not justified, as the Commission has not allowed such an adjustment in the past. As the Company pointed out, however, no basis was offered for holding those expenses constant over a two-year period, when in fact real inflation continued to occur. The increase from 2001 to projected 2002 is only 2.81%, and the increase from projected 2002 to projected 2003 is only another 2.81%. The Commission finds such increases to be reasonable in the light of general inflationary tendencies, and accordingly approves the Company's projection for 2003.

Institutional Advertising Expense

21. The Company included $76,000 in institutional advertising expense for the test year 2003, the same amount as stated for 2002. This is apparently primarily for community-involvement related advertising. The Commission finds that this expense falls under the types of advertising expenses which are recoverable as operating expenses under N.D.A.C. § 69-09-01-29(1)(e)(7) because such advertising benefits customers and serves the public.

Depreciation

22. The Company's projected depreciation expense for 2002 and for the 2003 test year were calculated using the depreciation rates derived in a full depreciation study performed for the Company by Stone & Webster Management Consultants, Inc. in 1992, except that the Company's internal studies were used for depreciation on computer network equipment, work equipment and transportation equipment. The proper treatment of depreciation necessitates thoroughly analyzing and reviewing additions, retirements, transfers of plant, positive and negative salvage, and accumulated depreciation for the entire history of each account in gas plant and common plant for the Company's distribution operations. The record contains no such detailed information, and the Commission finds that there is no basis for changing the current depreciation rates as determined in the 1992 depreciation study. A new depreciation study, now underway by a consultant engaged by the Company, will, when completed, be able to provide the basis for any appropriate changes in future proceedings. Accordingly, the depreciation expense figures presented by the Company are approved.

Financial Accounting Standard No. 143

23. A recently promulgated Financial Accounting Standard, "Accounting for Asset Retirement Obligations" [FAS 143] is designed to require companies to accrue for the expected retirement cost of an asset over the asset's useful life through increased depreciation, with higher cost pushed toward the retirement date of an asset due to the discounting methods used, rather than using levelized depreciation as this Commission and other regulatory bodies have traditionally done. It is not disputed that implementation of FAS 143 is complex and will be administratively

burdensome. The testimony in the record shows that while FAS 143 must and will be implemented at this time for financial reporting purposes, it is not necessary to implement the new standard immediately for regulatory and ratemaking purposes, as a specific Financial Accounting Standard (FAS 71) ("Accounting for the Effects of Certain Types of Regulation") provides the methodology for accounting for the differences.

The Company requested in this case that the Commission refrain from requiring implementation of FAS 143 for ratemaking purposes until the matter can be studied in detail in a specific generic proceeding in which all affected utility companies operating in North Dakota are made parties and have the opportunity for input. The Commission agrees that this is appropriate and according does not require the use of FAS 143 for ratemaking purposes in this proceeding.

Rate Design

24. The Company filed a class cost of service study and used the results of this study as a guide in distributing the total revenue requirements among the various customer classes and for pricing the components comprising the total rate applicable to each customer class. Staff witness King also filed a class cost of service study in this case. The primary difference between the two studies results from a difference in the allocation of the investment in distribution mains among the various rate classes. The Company advocates that distribution mains are most appropriately allocated on the basis of customers and peak day demand, in order to properly reflect the elements creating the costs. Mr. King, on the other hand, uses an allocation factor of energy and peak day demand. The Commission finds the Company's allocation methodology to be most appropriate and

adopts the class cost of service study as presented in Statement M of the Company's application.

25. The Company has proposed a change in its rate structure to more accurately reflect the components of the cost of serving its gas customers. The customer gas bill would be composed of three elements: (1) Basic Service Charge, (2) Distribution Delivery Charge, and (3) Cost of Gas. The basic service charge would be set at or nearly at the customer cost level for each rate class as identified in the Company's Class Cost of Service Study filed in this proceeding. The Basic Service Charge is reflected in the existing rate structure as the "base rate," but the level of the current base rate substantially under-recovers the actual customer cost, so that a portion of the actual customer cost is recovered in volumetric charges.

The Distribution Delivery Charge primarily reflects demand-related costs, as well as any customer costs not recovered in the Basic Service Charge. This portion of the rate is proposed as a flat commodity charge, and the declining block rate now applicable to residential and firm general service customers will be eliminated, as the customer related costs previously collected in the initial block of the rate will be recovered instead through the Basic Service Charge. The Cost of Gas component simply reflects the actual cost of gas which the Company passes through to its customers through the purchased gas adjustment clause.

The Commission finds that this change in the Company's proposed rate structure will promote rate stability and will have the beneficial effect of allowing gas customers to better understand the basis of their bills and will promote the general goal of rate design to match the charges to the actual cost of providing gas service to each customer. This in turn, will have the effect of sending appropriate price signals to customers and promoting conservation and the efficient use of resources.

25. The Basic Service Charge for residential service under the Company's rate proposal will be $0.39 per day, which is $11.70 for a 30-day month. The proposed rate structure will result in an average increase of approximately $2.00 per month for a typical residential customer.

26. In accordance with the Company's class cost of service study results, the Commission recognizes that the Company's allocation of the rate increase results in an increase for the residential and firm general service customers, with no increase for the Air Force and large interruptible classes, and a decrease for small interruptible customers and finds this allocation to be appropriate. Further, the Commission believes that the Company is correct in its position that the proposed allocation of the rate increase and proposed rate structure will provide relief to customers during the winter months when their heating requirements result in higher gas usage, by lowering the amounts collected on the basis of the volume of gas used, and the Commission finds that the proposed rate structure will help to eliminate cross-subsidization between and among customer classes.

27. The Commission accordingly finds that the Company's proposed rate structure provides for a basis of charges to its customers that is just and reasonable without discrimination,

28. The Company proposed a number of tariff changes as presented in Appendix B of its application that were not objected to by the Staff. The Commission finds these proposed tariff changes to be appropriate and that they should be adopted as proposed.

From the foregoing Findings of Fact, the Commission makes the following:

Conclusions of Law

1. The Commission has jurisdiction over the parties to and the subject matter of this proceeding.

2. Montana-Dakota's present gas rates are inadequate to provide the Company an opportunity to earn a reasonable rate of return on its property used and useful for the service and convenience of the public in providing natural gas distribution service to its customers in North Dakota.

3. The rates proposed by the Company herein will provide Montana-Dakota with the opportunity to earn a reasonable rate of return on its property used and useful for the service and convenience of the public in providing natural gas distribution service to its customers in North Dakota.

4. The application herein should be granted.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes the following

ORDER

It is hereby ordered that the Application of Montana-Dakota Utilities Co. for authority to increase its rates for natural gas distribution service to its North Dakota customers by substituting the proposed rate schedules referred to in Article V of the application in place of the rate schedules now in effect, be, and the same hereby is, granted, said new rates to become effective _____, 2002.

PUBLIC SERVICE COMMISSION

Susan E. Wefald, President

Leo M. Reinbold, Commissioner

Anthony T. Clark, Commissioner

Public Service Commission
State of North Dakota

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EXECUTIVE SECRETARY

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November 15, 2002

Jon Mielke, Executive Secretary
North Dakota Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505

RE: PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Dear Mr. Mielke:

Enclosed is the original and seven copies of staff's proposed Findings of Fact, Conclusions of Law and Order, and Brief in the above noted proceeding.

Sincerely,

William W. Binek
Chief Counsel

wwb/sdh

Enclosure

c: Don Ball, MDU
William Pearce
Doug Schulz, MDU

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Cover letter re filings

by Public Service Commission

11/15/2002 CC: Comm Legal Illona, Pat, Jerry Mike

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., A Division of MDU Resources Group, Inc.
Gas
Rates

Case No. PU-399-02-183

BRIEF

PRELIMINARY STATEMENT

On April 12, 2002, the North Dakota Public Service Commission received an application from Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) to increase its natural gas rates in North Dakota by $2,844,132 annually. MDU's application is based on a calendar 2003 projected test year.

In its application and supporting testimony and exhibits, MDU has requested an increase in its rates for gas distribution service of $2,844,132, or approximately 4.1 percent based on a forecast 2003 test year. MDU's requested return on rate base is 11.044 percent, inclusive of a return of 13.25 percent on the 51.687 percent of total capital that MDU asserted to be represented by common equity.

MDU also requested a significant restructuring of its rates, including a separation of gas distribution from gas supply charges, elimination of declining block commodity charges and dramatic increases in customer charges. Additionally, MDU has proposed that all increases be flowed into the firm residential and commercial rate schedules, that no change in rate levels be applied to the Air Force and large interruptible schedules, and that the small interruptible class should receive a rate reduction.

On April 24, 2002, the Commission suspended MDU's rates filed with its Natural Gas Rate Increase Application. On June 5, 2002, the Commission issued its Notice of Hearing Notice of Public Input Sessions, and Notice of Intervention Deadline. Public input sessions were held via video teleconference on July 15, 2002, in Bismarck, Dickinson, Williston, Minot, Devils Lake, and Jamestown. The technical hearing was

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Brief
by Public Service Commission
11/15/2002 CC: Comm Legal Illona, Pat, Jerry Mike

held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota on October 7-8, 2002.

The Notice of Hearing specified the issues to be considered at the technical hearing, which are:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

The Notice of Hearing provided that any person wishing to intervene as a party in the proceeding must file a petition for intervention by September 9, 2002. No one petitioned to intervene as a party in the proceeding.

STATEMENT OF ISSUES

I. STANDARDS AND GUIDELINES USED TO ESTABLISH THE FAIR RATE OF RETURN FOR MDU.

II. REVENUE REQUIREMENTS:

A. DEPRECIATION

B. ELIMINATION OF BONUSES AND 2003 LABOR EXPENSES

C. ELIMINATION OF SISP COSTS

D. RATE CASE EXPENSE AMORTIZATION PERIOD
E. GENERAL INFLATION ADJUSTMENT AND OTHER UNADJUSTED O&M EXPENSES
F. RATE OF RETURN
III. COST OF CAPITAL
A. CAPITAL STRUCTURE
B. COST OF DEBT
C. COST OF EQUITY
1. Flotation Cost
2. Selection of Comparison Companies
3. Forecast of Next Year's Dividends
4. Timing of Analysts' Forecasts
5. Procedure for Computing Retention Growth
6. Presentation of the DCF Results
7. Adjustment of Comparison Company Results for MDU's Risk
a. Gaske's "Benchmark Analyses
b. King's Risk Premium Test
IV. COST ALLOCATION AND RATE DESIGN
A. CLASS COST OF SERVICES STUDY
B. RATE DESIGN
C. DISTRIBUTION DELIVERY STABILIZATION MECHANISM
V. CONCLUSION

ARGUMENT

I. STANDARDS AND CRITERIA TO BE USED TO ESTABLISH THE FAIR RATE OF RETURN.

The Commission has the power under North Dakota law to establish rates for MDU under N.D.C.C. §§ 49-02-03 and 49-05-06. Those statues read as follows:

49-02-03. Power of public service commission to establish rates. -- The commission shall supervise the rates of all public utilities. It shall have the power, after notice and hearing, to originate, establish, modify, adjust, promulgate and enforce tariffs, rates, joint rates, and charges of all public utilities. Whenever the commission, after hearing, shall find any existing rates, tariffs, joint rates, or schedules unjust, unreasonable, insufficient, unjustly discriminatory, or otherwise in violation of any of the provisions of this title, the commission by order shall fix reasonable rates, joint rates, charges, or schedules to be followed in the future in lieu of those found to be unjust, unreasonable, insufficient, unjustly discriminatory, or otherwise in violation of any provision of law.

49-05-06. Hearing by commission on proposed change of rates. Whenever a notice or any schedule stating an individual or joint rate, classification, contract, practice, or rule, increasing or decreasing, or resulting in an increase or decrease in any rate, is filed with the commission, the commission may suspend by motion the rate, classification, contract, practice, or rule but the period of suspension may not extend more than seven months beyond the time when it would otherwise go into effect. Upon complaint or upon its own initiative without complaint the commission may order a hearing, upon due notice, concerning the propriety of the rate, classification, contract, practice, or rule. On such hearing, the commission shall establish the rates, classifications, contracts, practices, or rules proposed, in whole or in part, or others in lieu thereof, which it finds to be just and reasonable. At any such hearing, the burden to show that the increased rate or proposed change of rate, classification, rule, or practice is just and reasonable is upon the public utility applying for the increase. All such rates, classifications, contracts, practices, or rules, not suspended, on the expiration of thirty days from the time of filing with the commission, or of such lesser time as the commission may grant, become effective rates, classifications, contracts, practices, or rules, subject to the power of the commission, after a hearing had on its own motion or upon complaint, to alter or modify the same.

The United States Supreme Court has set forth appropriate standards and guidelines for determining rates that a public utility is permitted to earn. Those guidelines are set forth in *Federal Power Commission v. Hope Natural Gas Co.,* 302 U.S. 603 (1944), and *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923). These cases generally hold that the utility's return should be sufficient to maintain the utility's financial integrity, attract needed capital, and fairly compensate investors for risks they have assumed. The North Dakota Supreme Court has also held that an investor-owned utility is entitled

to earnings sufficient to pay its expenses and provide a fair and reasonable return to its investors. *Montana-Dakota Utilities Co., v. Public Service Commission,* 413 N.W.2d 308 (N.D. 1987).

Under our system of economic regulation of public utilities, referred to as ratemaking, the utility is required to serve customers and to charge just and reasonable rates for the service it provides, and the Commission's obligation is to enable the utility to earn a fair return on its investment. Determination of the appropriate rate base is essential for the determination of a fair return. In order to establish the just and reasonable rates of public utilities under North Dakota law, the Commission is required to determine the value of the property used and useful for the service and convenience of the public. *Application of Montana-Dakota Utilities Co.,* 102 N.W.2d 329, 334 (N.D. 1960); N.D.C.C. § 49-06-01. "The value of the property of a public utility, as determined by the public service commission for ratemaking purposes, shall be the money honestly and prudently invested therein by the utility less accrued depreciation." N.D.C.C. § 49-02-06.

In the present case MDU uses a projected average 2003 test year for purposes of deriving a revenue requirement. This is consistent with the general rule that normally the utility's average rate base and not a year-end valuation should be used. *Application of Montana-Dakota Utilities Co.,* 102 N.W.2d 329, 335 (N.D. 1960). The Court, quoting from a New Hampshire Supreme Court decision, stated that "rate base should relate to the period for which the earnings are being tested in order to reach a just result." MDU witness, Rita Mulkern, stated that rates from this proceeding will be in effect for 2003, and the closer that revenues, expenses and rate base reflect the levels to be experienced in 2003, the better the match will be and the better opportunity MDU will have to earn its authorized return. MDU is using a future test year as authorized by N.D.C.C. § 49-05-04.1.

II. REVENUE REQUIREMENTS

C. Wayne Fox, President of MDU Utilities Company, stated that the primary reasons for MDU's application are increased operation and maintenance costs, depreciation, and taxes other than income, and a higher required rate of return.[1]

Fox testified that MDU's last gas rate increase was in November 1994 in the amount of $565,000 annually, and that on January 15, 1999, MDU reduced its rates by $800,000.[2] During this period, 1994 through 2001, the consumer price index increased by almost 20 percent, but Fox testified that MDU had found ways of operating more efficiently and of taking advantage of new technologies so that it could hold the line on its gas rates.[3]

As recently as the year 2000, MDU's North Dakota gas operations earned a return of 11.92 percent[4]. However, in 2001, MDU's fully adjusted return was only 5.297 percent, and MDU's forecasts indicate that in 2002 and 2003 its return will fall to 4.298 and 2.332 percent, respectively.[5] During cross-examination, Fox asserted that the past improvements in labor efficiency have "flattened out" in the last year or so.[6] Apparently, MDU expects that flattening out to continue through 2003.

The Commission's Adversary Staff ("Staff") does not agree. In contrast to MDU's rate increase, Staff proposes that MDU's test year 2003 rates be decreased by $1,402,000. This reduction is based on a rate of return on rate base of 7.980 percent, inclusive of a 10.5 percent return on 44.55 percent equity proportion of total capital and a much lower cost of debt.

Staff witness Michael J. Majoros, Jr. identified six reasons for the $4,246,000 difference between MDU's proposed rate increase and the Staff's recommended rate reduction:

- A reduction in depreciation rates;
- Elimination of bonuses from MDU's costs and holding the 2003 labor costs equal to the projected 2002 levels;

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[1] Exhibit 3, page 6.
[2] Id.
[3] Id, page 7.
[4] Exhibit 10.
[5] Exhibit 2, Statement N, page 1
[6] Tr. Oct. 7, p. 46

- Elimination of the Supplemental Income Security Plan ("SISP") costs;
- A 5-year rather than 3-year rate case cost amortization period;
- Elimination of general inflation adjustment from "other" unadjusted operation and maintenance ("O&M") expenses; and
- Use of King's 7.89 percent return on rate base in lieu of MDU's proposed 11.044 percent return.

A. DEPRECIATION

Majoros' depreciation adjustment is the largest single adjustment proposed by Staff, amounting to a reduction of $2,172,000 in test year expense.[7] MDU's current depreciation expense is based on rates developed in a 1991 study performed by Stone & Webster.[8] Majoros performed a series of studies, which suggested to him that these depreciation rates are much too high. First, he found that annual depreciation accruals during the past five years had exceeded utility construction and acquisition by $28.5 million. When common plant construction and acquisition is added, the five-year accruals still exceeded expenditures by $409,000.[9] While it is not the purpose of depreciation to fund construction, this comparison indicates that MDU has obtained substantial cash flow from depreciation.[10] Majoros noted that in *Lindheimer v. Illinois Bell Telephone Company,* 292 U.S. 151 (1934), the Supreme Court found that excessive depreciation results in the extraction of capital from ratepayers.[11]

Majoros next observed that as of the end of 2001, the ratio of depreciation reserve to the original cost of distribution plant came to 70.7 percent. Based on his experience, this level of depreciation reserve is extraordinarily high and suggests that prior depreciation rates have been excessive. Majoros stated that the likely source of these excessive rates is the 140 percent negative salvage adjustment for Account 380 – Services[12] and the very short service lives of 36 and 34 years, respectively for

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[7] The difference between $3,261,000 and $1,089,000 as shown on Exhibit 19, MJM-1, page 3.
[8] Exhibit 19, page 10.
[9] Exhibit 20.
[10] Exhibit 19, page 6.
[11] Id., page 8.
[12] Late Filed Exhibit 1 explains the source of the 140% negative salvage for the Service account. It compares the original cost of retired services with the cost of removal. The composite ratio of original cost to removal cost for all Services removed between 1996 and 2000 is 138%. The removed services date back to 1926, but all of the removal costs were incurred since 1996. The ratio is so high because it compares dollars spent up to 75 years ago with dollars spent only since 1996. The result is a ratio that captures the inflation that has taken place over the past 75 years. When that ratio is then applied to current plant balances to calculate depreciation expense, it effectively projects that same rate of inflation to the end of the current plant's life. Ratepayers are

Account 376 – Mains and Account 380 – Services.[13] He supported his observation with respect to service lives by a geometric mean turnover analysis, which indicated a 108-year average service life for Mains and a 69-year service life for Services.[14]

Majoros did not, however, adjust any of the service lives of MDU's plant. His sole adjustment was to the salvage factors. This adjustment was based on an obvious inconsistency between the net salvage assumed in the Stone and Webster study and actual net salvage that MDU has experience during the past five years.

The Stone & Webster study developed depreciation rates that resulted in a large recovery of "negative salvage," that is, cost of removal. Specifically, its depreciation rates were designed to recover total gas plant of $102.5 million plus negative salvage (removal) costs of $46.9 million.[15] Even the $21.7 million in common plant was presumed to require recovery of an additional $1 million in net negative salvage costs.

Yet, MDU has not experienced negative net salvage. To the contrary, MDU's actual net salvage experience has been positive. In every year since 1997, MDU has received more in salvage value for its retired gas and common plant than it has paid in removal cost. The total cumulative 5-year net positive salvage receipts for gas plant have amounted to $1,444,452. For common plant, net positive salvage receipts have come to $5,529,260.[16]

To correct for this obvious over-recovery of net salvage, Majoros proposed to adopt the Stone & Webster lives and survivor curves for each account with no net salvage overlay. The account-by-account depreciation rates would thus represent pure depreciation, that is, solely the recovery of original cost. To recognize net salvage, Majoros proposed to deduct from total annual depreciation the average annual amount of net positive salvage for gas plant, plus the net positive salvage of common plant distributed between gas and electric operations based on their respective net salvage amounts. Total depreciation of test year plant would be $1,937,000. The annualized

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thus being forced to pay for future inflation that presumably will match past inflation. By charging ratepayers now for inflation in the future, this practice fails to recognize the much higher present value of current ratepayer dollars over the Company's future removal cost dollars.

[13] Exhibit 19, page 10.
[14] Id. page 11.
[15] Id. MJM-4, page 1.
[16] Id., MJM-6

positive salvage offset would be $848,000, for a net test-year depreciation expense of $1,089,000.[17]

Majoros noted that in addition to matching net salvage accruals with actual net salvage experience, his treatment of removal costs conforms with Generally Accepted Accounting Principles ("GAAP") as recently refined in Statement of Financial Accounting Standards No. 143 ("FAS 143"). That standard, which MDU must adopt this year, requires companies to determine whether they have a legal obligation to retire property and incur the cost of removal or dismantlement. If they do, they must declare the present value of the future "asset retirement obligation" costs as a liability on their books to be amortized over the remaining life of the asset. If they do not, then the American Institute of Certified Public Accounts' Statement of Position on Property, Plant and Equipment would require that these costs be expensed as they are incurred.[18]

Majoros testified that MDU has not determined whether it has asset retirement obligations, let alone what the present value of those obligations might be. For this reason, it is appropriate to reflect net salvage experience as a rolling five-year average of actual net removal costs. That is what his adjustment does.[19]

In rebuttal, MDU presented the testimony of John A. Jeter, a retired accountant from Arthur Anderson & Co.[20] Jeter argued that Majoros had not done a depreciation study, that his review of the current depreciation rates is superficial and contains many errors, and that he has no basis for proposing changes in depreciation rates. According to Jeter, the current depreciation rates are based on a comprehensive study prepared in 1991 and used beginning 1994. He argues that no adjustment of depreciation rates should be entertained until the current depreciation study is completed and an appropriate review has taken place.[21]

Much of Jeter's testimony focused on Majoros' evidence that MDU's depreciation appears to be excessive and that its service lives are too short. He argued that Majoros had not done the sort of comprehensive study of service lives that Stone & Webster had performed. On cross-examination, however, he admitted that since Majoros had

[17] Id., MJM-7, page 3.
[18] Id., page 12.
[19] Id., pages 13-14.
[20] Exhibit 22.
[21] Id., page 24.

not changed service lives, his criticisms of Majoros' service life discussion were irrelevant to the outcome of this case.[22]

Jeter's only defense of MDU's negative net salvage assumptions was to assert that the 1991 depreciation study by Stone & Webster is a much more reliable source of information regarding net salvage than a cursory look at net salvage for all accounts over a five year period.[23] He never explained why, nor did he refute Majoros' observation that the Stone & Webster study had recommended large negative salvage allowances, while MDU's actual net salvage experience has consistently been positive.

Jeter's principal response to Majoros' net salvage discussion was to attack his proposal to adjust overall depreciation by $848,000 based on the past five years' actual experience. He argued that the net salvage amounts used by Majoros varied from year to year and that they reflected the sale of an office building for approximately $4.6 million. In something of a reach, Jeter noted that the electric net salvage amounts, not at issue in this case, included an insurance adjustment.[24]

Jeter also argued that Majoros has allocated common property net salvage based on the direct net salvage amounts of the gas and electric operations, which is not the basis used by MDU. He failed to mention how MDU does allocate these common net salvage amounts. He concluded that "the proposed adjustment is not supported by any evidence and should not be approved."[25]

The variability of net salvage from year to year is the very reason Majoros used a five-year average of net salvage experience. Jeter never explained why it should be the basis for rejecting Majoros' adjustment.

Jeter's statement that the Majoros depreciation adjustment is "not supported by any evidence" is incorrect. During his re-cross examination, Jeter read the following passage from the NARUC Public Utilities Depreciation Manual, dated August 1, 1996:

> When estimating future net salvage, every effort should be made to ensure that the estimate is as accurate as possible. Normally, the process would start by analyzing past salvage and cost-of-removal data

[22] Tr. Oct 8, page 353.
[23] Exhibit 22, page 16.
[24] Id.
[25] Id., page 23.

and by using the results of this analysis to project future gross salvage and costs of removal.[26]

That is exactly what Majoros did. He analyzed past salvage and cost-of-removal data and found that over the past five years salvage has consistently been greater than cost of removal for both gas plant and common plant. His adjustment reflects that undeniable and fully supported finding.

MDU would very much like to sweep this issue under the rug. To this end, it has employed two tactics. The first is to urge the Commission to defer any consideration of depreciation until its new depreciation study, currently being conducted by AUS Consulting, is completed by the end of this year.[27] The second is to contend that over-depreciation is good for ratepayers. Had Majoros' adjustment been implemented in 1995, MDU's revenue requirement would be higher than it is now. [28]

Both of these ploys should be ignored. One would suppose that MDU, knowing that it was going to file a rate case in advance of the coming winter's heating season, would have arranged to produce a depreciation study in time to be incorporated into this case. It did not do so. Instead, it apparently proposes to saddle the Commission with a separate, single-issue rate proceeding sometime next year. Notwithstanding MDU's excuses for its delay in producing the study, one is left with the suspicion that MDU may have feared the very results suggested by Majoros – that the current depreciation rates are too high. If so, then the present rate case would have been severely compromised.

No element of MDU's revenue requirement should be exempted from this case. Specifically, MDU should not be permitted to continue to charge ratepayers depreciation expense that is clearly excessive. A new depreciation study will not alter the fact that in recent years net salvage has consistently been positive, while the current depreciation rates incorporate a very large allowance for negative salvage. A new depreciation study should reflect that fact. Indeed, if a new depreciation study were to claim that forecast removal costs are higher than forecast salvage proceeds, then it should be dismissed as inconsistent with demonstrated Company experience.

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[26] Tr. Oct 8, page 375.
[27] Exhibit 22, page 4.
[28] Id., page 11.

MDU's other argument is even less worthy of Commission consideration. It is that the cumulative effect of overcharging depreciation is to reduce the rate base to the point where the reduction in return and income allowances exceeds the overstated depreciation expense. Jeter multiplied Majoros' $2.172 million depreciation expense reduction by the 8 years since 1995 to derive a presumed increment in the rate base of $17.376 million. He then calculates that at MDU's proposed 11.044 percent return and 39.61 percent tax rate, the revenue requirement increase from this rate base increment would be $3.2 million, which is more than Majoros' depreciation expense reduction of $2.172 million.[29]

This calculation is wrong both mathematically and conceptually. It is wrong mathematically because, as Jeter admitted on cross-examination, MDU's plant in 1995 was smaller than it is now, so Majoros' adjustment would have been less.[30] It is incorrect to multiply Majoros $2.172 million adjustment, which applies to a 2003 test year, by the eight years between 1995 and 2002.

The calculation is conceptually wrong because there is no justification for charging ratepayers excessive depreciation, quite regardless of the effect on the rate base. As the Supreme Court found in *Lindheimer*, excessive depreciation results in the extraction of capital from ratepayers. It is improper from a legal, a regulatory, an economic, and an accounting standpoint.

B. ELIMINATION OF BONUSES AND 2003 LABOR EXPENSES

Majoros has proposed to eliminate bonuses from the forecast test year and to hold test year labor costs to their 2002 levels. MDU had included average bonuses for the years 1999-2001 in the amount of 6.1 percent of labor costs. Applied to the $8,239,000 in labor costs in 2002, the bonus elimination comes to $503,000. The 2003 labor cost increase eliminated by Majoros amounts to $236,000. These direct labor cost adjustments reduce payroll taxes by $40,000 in 2002 and $60,000 in 2003.[31]

Majoros testified that given the state of the economy and the fact that MDU is requesting a rate increase, it would be unreasonable to include bonuses in the revenue

[29] Id., page 11.
[30] Tr. Oct 8, page 349.
[31] Calculated from the data presented on Exhibit 19, MJM-9, pages 1 and 2.

requirement.[32] As regards labor costs, Majoros charted the overall pattern of operating and maintenance costs since 1996. These costs remained relatively stable through the year 2000, but they have since taken a sharp upturn, and MDU projects a 5.7 percent increase each year from 2000 through 2003. This rate of increase exceeds predicted inflation of 2.8 percent annually.[33] Majoros accepted the 2002 labor cost increase, but objected to extrapolating that increase through 2003.

On rebuttal, Richard D. Spratt, MDU's Vice President – Human Relations, argued that bonuses are an integral part of his Company's overall compensation philosophy to remain competitive with other employers. Part of that compensation is intentionally put at risk in the form of bonuses that are paid on the basis of various goals, including MDU's overall profitability. Spratt presented the results of an industry survey that showed most utilities pay bonuses not only to management employees, but to salaried and hourly employees as well. Spratt stated that the elimination of bonuses would risk rendering MDU uncompetitive relative to other employers.[34]

The issue before the Commission is not whether MDU should pay bonuses or increase salaries. Staff agrees with Spratt that MDU must remain competitive with other employers, and that bonuses and raises are legitimately part of that effort. The issue that the Commission must decide is whether such bonuses and raises properly should be included as elements of a rate increase.

As acknowledged by Fox, the reason for this rate increase application is the apparent collapse of MDU's ability to wring further efficiency out of its operations.[35] For six years, from 1994 through 2000, MDU was able to sustain an annual rate of inflation of approximately three percent without ever increasing its distribution rates. Indeed, it reduced its rates in 1999. It did this through improved efficiency. Fox testified that MDU reduced its employees by 30 percent since 1994. In that year there were 248 customers per MDU employee. In 2001, one employee was serving 370 customers.[36]

Then suddenly, beginning in 2001, MDU's lost its ability to stay ahead of inflation, so it must now come before this Commission to ask for a rate increase.

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[32] Exhibit 19, page 15.
[33] Id., page 5 and MJM-2.
[34] Exhibit 27.
[35] Tr. Oct. 7, page 46.
[36] Id.

MDU's rate increase application not only implies but asserts that this loss of efficiency will continue through 2003. Mulkern testified that while all of the past employee reductions are reflected in the 2001 base period data, no further reductions are forecast for 2002 and 2003.[37]

During her examination of Mulkern, Commissioner Wefald alluded to the possibility that the Commission might want to give MDU an incentive to practice savings and to find ways to achieve new savings.[38] Staff commends this objective.

MDU's rate increase application provides no incentives whatever to improve efficiency. The deterioration in productivity improvement during the years 2001 and 2002 is simply extrapolated into 2003. MDU should not be encouraged to perpetuate its own loss of efficiency. While the 2002 increases in labor costs might be allowed because they have already happened, no further deterioration of labor productivity should be built into the revenue requirement imposed on ratepayers. For this reason, the 2003 labor cost increase should be disallowed.

The same objective of incentivizing MDU to regain its previous levels of productivity improvement applies to bonuses, only here the incentives apply directly to employees. Apparently, a significant portion of MDU's bonuses is granted on the basis of MDU's overall profitability. Spratt testified that two years ago – presumably in 2000 – 75 percent of MDU's employees received 7 percent bonus. Last year, 2001, their bonus was 0.6 percent.[39] Presumably, these bonus levels reflected the fact that in 2000, MDU earned 11.96 percent on its North Dakota Gas Operations,[40] but in 2001, it earned only1.6 percent.[41]

If profitability drives bonuses, as it appears to, then it is altogether inappropriate to include bonuses in a revenue requirement that drives a rate increase. The reason MDU needs the rate increase is that it is not profitable. If it becomes profitable as a result of a rate increase, that profitability will not have come about because the employees have performed particularly well. To the contrary, it will be because the employees have not performed well, and MDU needs rescue from the Commission.

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[37] Tr. Oct. 8, page 473.
[38] Tr. Oct..8, page 475.
[39] Tr. Oct. 8, page 510.
[40] Exhibit 10.
[41] Exhibit 10, corrected at Tr. Oct 7, page 58.

The revenue requirement imposed on ratepayers should not include rewards for poor performance. For this reason, bonuses should be disallowed.

C. ELIMINATION OF SISP COSTS

The Supplemental Income Security Plan ("SISP") is a plan that provides supplemental pension benefits to key employees. "Key employees" are officers, directors and senior managers of MDU Resources and MDU Utilities. The plan is expected to cost $259,000 in 2002 and $265,000 in test year 2003.[42]

SISP was initiated in 1982, but MDU never sought its inclusion in revenue requirement until Case No. PU-399-01-186. In its April 24, 2002 decision in that case, the Commission accepted Staff's observation that this plan benefits only the top few employees, those that are already quite well paid. The Commission concluded that it is inappropriate for ratepayers to bear the expense of the SISP costs.[43]

MDU witness, Richard A. Espland, acknowledged that his testimony was essentially the same as it was in Case No. PU-399-01-186.[44] Espland acknowledged that SISP benefits only MDU's high salaried employees with income ranges from a low of $75,000 to its president at around $250,000 to $300,000.[45] Espland also agreed that none of the Public Utility Commission's in the jurisdictions where MDU provides natural gas utility services have approved a ratepayer funded SISP program.[46] The Commission took administrative notice of the Findings of Fact, Conclusions of Law and Order in Case No. PU-399-01-186.

If exclusion of SISP was appropriate in Case No. PU-399-01-186, it is even more appropriate in this case. That earlier case was a Staff-initiated proceeding to reduce MDU's electric rates. This case is a Company-initiated rate increase proceeding. As noted earlier, the need to increase rates after an eight-year period of price stability is indicative of management's failure to maintain its previous rate of productivity improvement. The management personnel who are most responsible for this failure are the very employees who benefit from SISP. This is not the time to reward them at

[42] Exhibit 19, MJM-10.
[43] Case No. PU-399-01-186, Findings of Fact, Conclusions of Law and Order, April 24, 2002, ¶68.
[44] Tr. Oct. 7, page 148
[45] Tr. Oct. 7, page 151
[46] Tr. Oct. 7, pages 151-152

ratepayers' cost. For this reason, the SISP expense should be disallowed again in this case.

D. RATE CASE EXPENSE AMORTIZATION

MDU proposes to amortize $168,000 in rate case expenses over three years at $56,000 per year. Majoros proposes to amortize the same amount over five years at $34,000 per year, for a difference in annual cost recognition of $22,000.[47] Mulkern suggested that if the five-year amortization is adopted, the unamortized balance should be included as a rate base addition.[48]

The basis of Majoros' proposal is the historical period between rate cases.[49] Fox stated that MDU's last rate increase proceeding was Case No. PU-399-94-297 decided in 1994, and a rate reduction occurred in 1999 in Case No. PU-399-96-325.[50] This represents two rate cases in eight years, or one every four years. MDU has rounded down to three, and Staff has rounded up to five.

There are two important reasons for adopting a longer, rather than a shorter amortization period for rate case expenses. The first is that once an amortization becomes embedded in the revenue requirement, it remains there until a new revenue requirement has been calculated. Thus, if the Commission accepts MDU's requested three-year amortization, and MDU does not participate in a rate case for another five years, then it has effectively over-recovered its expenses by a factor of 67 percent (5/3). If the reverse occurs, where MDU amortizes rate case costs over five years but has a rate case in three, the amortization can be continued in the new rate case, so that MDU ultimately recovers its costs, but only its costs.

The second reason for a longer amortization period is to provide a disincentive for MDU to initiate rate cases. It is a very small disincentive, but it is nonetheless symbolic. MDU should have to wait for five years to recover its rate case costs rather than the much shorter three years that it seeks.

Mulkern's proposal to include the unamortized balance of the rate base expenses faces practical and philosophical problems. Practically, it is impossible to

[47] Exhibit 19, MJM-11.
[48] Exhibit 25, page 2.
[49] Exhibit 19, page 15.

identify the amount that should be included in rate base because it declines each year. There would have to be some sort of annual adjustment in rates to recognize this declining amount. Philosophically, it would be difficult to explain to ratepayers why they should pay a return, which includes shareholder profits, on costs MDU incurred to increase their rates. Mulkern's proposal should be dismissed as unworkable.

E. GENERAL INFLATION ADJUSTMENT AND OTHER UNADJUSTED O&M EXPENSES

In 2001, MDU incurred $89,780,000 in O&M expenses, of which $76,842,000 represented the cost of acquiring gas. Of the remaining $12,938,000 O&M cost relating to distribution, MDU developed specific forecasts for $9,249,000 based on projected changes for various categories of costs, e.g. labor, benefits, insurance, advertising. This left a catch-all category of $3,689,000 of "other" O&M costs, which MDU assumed would increase between 2001 and 2003 by 2.8 percent annually, the assumed rate of general inflation[51]

Majoros noted that the Commission had never previously allowed this sort of inflation-based adjustment, and he recommended that it not start now.[52] The elimination of this adjustment reduces test-year expenses by $209,000.

This adjustment raises the same issues that were discussed with respect to labor costs, but adds some others. As with labor costs, MDU is projecting into the test year its apparent failure to maintain the rate of efficiency improvement that it was able to sustain during the years 1994-2000. As with labor costs, there should be some incentive to resume the search for productivity improvements that permit MDU to remain profitable without rate increases.

Additionally, there is some question whether these particular costs are subject to inflation. Of the $3,689,000 in 2001 costs within this "other" O&M category, $1,709,000 is non-labor Administrative and General costs. Presumably, this includes such things as office building rent and depreciation, office materials and supplies, and office furniture. Many of these costs are fixed in nature and would not increase with inflation.

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[50] Exhibit 3, page 6.
[51] Exhibit 2, Statement N, page 14.
[52] Exhibit 19, page 16.

The second largest component of the "other" O&M category, accounting for $981,000 in 2001, is Customer Accounts, a portion of which is accounts receivable.[53] Accounts receivable would vary not by general inflation, but by the overall size of the total amount billed to customers, including the cost of gas. As demonstrated graphically in Mulkern's rebuttal exhibit RAM-2, gas prices spiked in the last months of 2000 and the first months of 2001, but have since moderated, falling to levels equal or below their 1999 values.[54] The level of accounts receivable would have followed this same pattern, but with several months' delay. They, too, would have spiked in 2001, and then declined as prices returned to their earlier levels. This means that accounts receivable were probably much higher in 2001 than in 2002 or 2003. It is wrong to project them to increase from 2001 through 2003 at the rate of overall inflation.

For these reasons, MDU's proposal to increase "other" O&M costs at the rate of inflation through 2003 should be rejected.

F. RATE OF RETURN

MDU has proposed a post-tax rate of return of 11.044 percent, which includes a 13.25 percent return on common equity. Staff has recommended a return of 7.98 percent, including a 10.5 percent return on common equity. Staff's position regarding the appropriate rate of return is fully explained in the next section of this brief.

III. COST OF CAPITAL

As stated previously, MDU has proposed a post-tax rate of return of 11.044 percent, which includes a 13.25 percent return on the 51.687 percent of its capital represented by common equity. Staff has recommended a return of 7.98 percent, including a 10.5 percent return on 44.55 percent of MDU's capital that it finds to be represented by common equity. Using MDU's 39.61 percent federal and state income tax rate,[55] the pre-tax rates of return can be calculated as follows.

[53] Tr. Oct 8, page 469.
[54] Exhibit 25, RAM-2.
[55] Exhibit 2, Statement N, page 20.

MDU:[56]

	Cost	Proportion	Post-Tax	Tax	Pre-tax
Long-term Debt	9.180%	43.039%	3.951%		3.951%
Preferred Stock	4.662%	5.274%	0.334%	0.090%	0.244%
Common Equity	13.250%	51.687%	9.562%	2.713%	6.849%
Total		100.000%	13.847%		11.044%

Staff:[57]

	Cost	Proportion	Post-Tax	Tax	Pre-tax
Long-term Debt	6.167%	47.92%	2.96%		2.96%
Short-term Debt	4.542%	2.78%	0.13%		0.13%
Preferred Stock	4.630%	4.75%	0.31%	.09%	0.22%
Common Equity	10.50%	44.55%	6.53%	1.85%	4.68%
Total		100.00%	9.93%		7.98%

The difference between the two pre-tax rates of return is 3.917 percent. When applied to MDU's projected test year rate base of $19,681,000,[58] this difference amounts to $771,000. When applied to the Staff's recommended rate base of $20,768,000,[59] the difference comes to $813,000.

As demonstrated in the foregoing tables, the Staff differs from MDU with respect to all of the components that make up the rate of return: the capital structure, the cost of debt, and the cost of equity.

A. CAPITAL STRUCTURE

Capital structure refers to the makeup of MDU's capital, that is, the mix of debt, preferred stock and equity. Two factors account for the disagreement between Staff and MDU. The first is Staff's inclusion of short-term debt, and the second is Staff's use of year-end 2001 capital structure instead of MDU's projection of its capital structure into 2003.

In its initial filing, MDU excluded all short-term debt from its proposed capital structure. Staff's rate of return witness, Charles W. King, testified that the makeup of the capital structure used to develop a rate of return should reflect the nature of the rate

[56] Exhibit 4, page 3.
[57] Exhibit 15, page 34.
[58] Exhibit 2, Statement N, page 1.

base to which that return is applied. If the rate base consists solely of capital investments in plant and equipment financed by long-term debt, preferred stock and equity, then it might be appropriate to exclude short-term debt. But MDU's rate base also includes materials and supplies inventories, fuel stocks, and prepayments, which are short-term commitments that will be financed in part with short-term debt. For this reason, he included short-term debt in the capital structure.[60]

On rebuttal, MDU witness Craig Keller argued that the items to which King referred, materials and supplies, prepayments and fuel stocks remain relatively constant, not changing materially from one month to another. While classified as short-term assets, they support long-lived assets such as plant, property, equipment and related items. They are therefore financed by long-term debt, according to Keller.[61]

At the hearing, King responded to Keller by producing Exhibit 13, which shows the month-to-month amounts of each of the major elements of working capital during the 13 months from December 2000 through December 2001. That exhibit demonstrates that net working capital varied from negative $53,000 in January to positive $306,000 in July. These widely varying amounts could not possibly have been financed with long-term debt.

As noted, the second difference between the Staff's and MDU's capital structure relates to the use of historical vs. forecast data. King drew the amounts of debt, preferred stock and common equity from Company supplied data for calendar year 2001. He calculated average long-term debt from Exhibit 2, Statement A, page 2; short-term debt from a response to a data request (Exhibit 15, CWK-1); and preferred stock and common equity from Exhibit 2, Statements A and F, page 1.

MDU's capital structure was presented on Statement F, page 3 as its projected 2003 capital mix. King objected to this use of a projection on the grounds that it is effectively a creation of MDU that has no basis in any verifiable financial statements.[62]

On rebuttal, MDU witness Keller argued that NDCC § 49-05-04.1 permits MDU to use a forecast test year and that Staff's other witness, Majoros, had accepted the 2003 test year as the basis for revenue requirements. Failure to use a forecast capital

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[59] Exhibit 19, MJM-1, page 1.
[60] Exhibit 15, page 4.
[61] Exhibit 23, page 2.

structure would result in a "mismatch" with the rest of the revenue requirement calculation.[63] Keller argued that MDU possesses a financial forecasting system that uses known debt scheduling and projects equity by forecasting earnings and deducting dividends.

In his oral testimony, King pointed out that MDU had used an historical capital structure in its recent electric case. He argued that the purpose of the future test year is to capture exogenous changes that can be objectively determined, such as inflation or the expansion of the system. By contrast, the capital structure is a creation of MDU's management. There is no way of verifying that it will change in the manner MDU predicts. For this reason, most commissions use recent historical capital structures. Otherwise, MDU has the opportunity to game the regulatory system by projecting a more expensive capital structure, one with greater equity than now exists.[64] A comparison of MDU's 2001 capital structure with its forecast 2003 capital structure reveals that this is exactly what MDU has done in this case. For this reason, an historical capital structure should be used in this case.

B. COST OF DEBT

MDU's claimed cost of debt in 2001 is 9.302 percent, and its projected 2003 debt cost is 9.180 percent. These values are calculated on Exhibit 2, Statement F-1, pages 1 and 3. Those pages show only two debt issues, First Mortgage Bonds and Pollution Control Bonds, totaling $133.5 million in 2001 and $132.6 million in 2003.

Yet, Statement A, pages 11 and 12 of that same exhibit reveals that there is substantially more to MDU's debt than these two issues. As of December 31, 2001, there were $405.2 million in senior notes, $219.7 million in commercial paper, a revolving line of credit of $25 million, and term credit agreements of $11.8 million. Using the cost values shown on those pages, King calculated that the blended cost of MDU's debt is 6.167 percent, more than 300 basis points lower than MDU proposes.[65]

It turns out that the difference between Staff and MDU revolves around what "MDU" actually is. According to MDU witness Keller, only the First Mortgage and

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[62] Exhibit 15, page 4.
[63] Exhibit 23, page 4.
[64] Tr. Oct. 7, page 183.

Pollution Control bonds relate to MDU Utilities. All of the other debt pertains to Centennial Holdings, which holds title to the non-regulated operations of the parent Company, MDU Resources Group, Inc. ("MDU Resources"). The two sets of debt are not fungible. MDU has no access to Centennial's debt and vice versa.

On cross-examination, however, Keller made it quite clear that there is no such entity as the Montana-Dakota Utilities Company. The only legal entity is the parent Company, MDU Resources, and only that company can issue debt. Neither the utility operation nor Centennial have any debt in their own right.[66]

Keller testified orally that MDU Resources Group had attempted to build a "firewall" between the debt of MDU Utilities and that of Centennial. The purpose, he argued, was to protect the utility operations from the effect of default on Centennial's debt. If Centennial or one of its subsidiaries goes bankrupt, then the bankruptcy judge would not be able to "collapse the corporation" and gain access to the utility's assets. For this reason, MDU Resources does not commingle the funds raised for the utility with those raised for Centennial.[67]

These are laudable objectives, but it is not clear how far they go. On cross-examination, Keller conceded that if the bankruptcy of either MDU Resources' regulated or its unregulated operations caused the parent to declare bankruptcy, then the bankruptcy court would look at all of MDU Resources' assets to satisfy creditors' claims, including those of the regulated utility.[68]

King suggested that there might be another, less altruistic reason for attempting to isolate Centennial's debt from that of the utility operations. It is to ensure that ratepayers pay the very high costs of the First Mortgage bonds and receive no benefit from MDU Resources' other, lower-cost financing resources.[69] While MDU Resources may have written its low-cost financing instruments to direct funds to Centennial and its subsidiaries, that was an artifice to "game" the regulatory system into ascribing only the

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[65] Exhibit 15, CWK-2.
[66] Tr. Oct 7, page 129.
[67] Tr. Oct 8, pages 380-383.
[68] Tr. Oct 8, page 393.
[69] Exhibit 15, page 7.

highest cost debt to regulated service ratepayers. MDU Resources could have used the Centennial funds anywhere had it written the debt instruments differently.[70]

In the end, all of MDU Resources' debt is secured by all of MDU Resources' assets. This means that in the end, all of its debt is fungible. For this reason, it is appropriate to use the blended cost of all of MDU Resources' debt as the cost of debt for MDU's utility operations.

C. COST OF EQUITY

MDU's rate-of-return witness, J. Stephen Gaske, recommended a return to equity of 13.25 percent. This return was developed using three variants of the Discounted Cash Flow ("DCF") approach, plus a series of "benchmark analyses."

For his DCF results, Gaske drew a distinction between "Investor Requirements" and "Cost of Capital" based on his belief that stock flotation costs, equivalent to 4.75 percent of the return, must be included in the latter. Because MDU's parent company, MDU Resources Group, Inc. is heavily engaged in non-regulated activities, Gaske used a "proxy group" of six companies based on Moody's utility series. His DCF results for these companies were as follows:[71]

	Investor Requirements	Cost of Capital
Second-stage Retention Growth	11.94%	12.51%
Basic DCF	12.61%	13.21%
Primary DCF	12.63%	13.22%

Gaske's benchmark analyses consisted of four risk premium comparisons using historical differences in earned returns to equity from large and, alternatively, small companies relative to current yields on U.S. Treasury bonds and corporate bonds. He also identified the recent returns on per-share book value of S&P 500 corporations and Value Line's list of industrial companies. All of his benchmark indicators were higher than any of his DCF returns.[72]

[70] Tr. Oct. 7, page 185.
[71] Exhibit 4, page 32.
[72] Id.

Gaske's final selection of 13.25 percent was based on his belief that the risk of MDU's gas distribution business is slightly higher than that of his proxy group of gas distribution companies. He based this belief principally on the smaller size of MDU relative to the proxy companies. Small size, argued Gaske, translates into greater risk.[73]

King recommended a very different return to equity: 10.5 percent.[74] Paradoxically, King followed most of the same procedures as Gaske, at least with respect DCF analyses, which was the principal analytical tool used by both witnesses. Like Gaske, King used a comparison group of gas distribution companies. Also like Gaske, King used a forecast of next year's dividends for the dividend yield portion of the DCF formula. King also used both analysts' forecasts and the concept of earnings retention to calculate the growth component of that formula – as do Gaske. Finally, both King and Gaske adjusted their final recommendations based on their assessments of the risk of MDU's gas distribution activities relative to that of the comparison companies.

The explanation for the dramatic 275 basis point (2.75%) difference between the recommendations of the two witnesses lies in the details of the application of the DCF formula. As used by both witnesses, the DCF formula is the sum of next year's dividend yield on MDU's stock and the expected future growth rate in its dividends and earnings.

The differences between the Gaske and King applications of the DCF formula relate to the following elements:

1. Inclusion of flotation costs;
2. Selection of comparison companies;
3. Forecast of next year's dividends;
4. Timing of analysts' forecasts;
5. Computation of earnings retention growth;
6. Presentation of the DCF results; and
7. Adjustment of comparison companies results to reflect MDU's risk.

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[73] Id., page 34.
[74] Exhibit 15, pages 2 and 27.

1. Flotation Costs

As noted earlier, Gaske drew a distinction between "investor requirement" and "cost of capital," with the difference being cost of issuing new shares in public stock offerings. Gaske quantified this cost as 4.75 percent, based on a representative sample of flotation costs incurred with 34 new common stock issues by natural gas transmission and distribution companies between 1992 and 2001.[75]

King agreed with Gaske that flotation costs should be recovered, but he questioned the propriety of applying a ratio for these costs to the entire amount of common equity. Flotation costs are incurred only when a company issues new stock, and then only when there is a public stock offering. Existing stock incurs no flotation cost, and even new stock incurs no such costs if it is distributed as an employee or shareholder benefit either through options or as bonuses.[76]

King noted that the effect of Gaske's flotation cost adjustment is to increase his equity return by 60 basis points, or .60 percentage points. When multiplied by the $1.125 million book equity value of the MDU Resources, Inc., this allowance amounts to $6.75 million annually, which is substantially more than the $5.4 million in flotation costs that MDU has incurred over the past five years.[77]

King suggested that if a flotation cost adder is to be used, it should be equal to a reasonable estimate of the annual flotation cost incurrence divided by the entire amount of MDU's equity. In MDU's case, annual flotation costs during the past five years have been about $1.1 million. MDU's total book equity value is $1,125 million, for a flotation cost allowance of 0.1 percent. This amount is so small as to be lost in the rounding. For this reason, he recommended that there be no explicit flotation cost adder.[78]

During the rebuttal phase of the hearing, Gaske distributed an exhibit that purported to demonstrate that failure to include flotation costs in the return of a company's stock trading at book value would result in the dilution of the book value of that company's shares.[79] On cross-examination, however, Gaske admitted that all of

[75] Exhibit 4, page 12 and JSG-2, Schedule 3.
[76] Exhibit 15, page 28.
[77] Id.
[78] Id.
[79] Exhibit 31.

King's comparison companies had per-share market values higher than book value, and that when such companies sell new stock, the effect is to increase book value, not dilute it.[80]

In Case No. PU-399-01-186, involving MDU's electric rates, the Commission rejected Gaske's flotation cost adder.[81] It should do so again.

2. Selection of Comparison Companies

As noted earlier, both witnesses acknowledged that the heavy involvement of MDU's parent company, MDU Resources Group, Inc., in non-regulated activities effectively precluded using that company as the basis for finding the return to equity of its gas distribution business in North Dakota. Necessarily, this required the selection of companies whose primary business is gas distribution. Gaske picked six companies from Moody's list of natural gas distribution companies.[82] King chose 11 companies from Value Line's Investment Survey based on the criteria that they must have investment grade bond ratings, total operating revenues over $100 million, and derive more than 75 percent of their revenue from gas distribution services.[83] The two lists are as follows:

King Comparison Companies[84]	Gaske Proxy Group[85]
Atmos Energy Corp.	AGL Resources
AGL Resources	Keyspan Corporation
Cascade Natural Gas Corp.	LaClede Group
LaClede Group, Inc.	Northwest Natural Gas
NICOR, Inc.	People's Energy Corp.
Northwest Natural Gas Co.	WGL Holdings, Inc.
People's Energy Corp.	
Piedmont Natural Gas Co.	
South Jersey Industries, Inc.	
Southwest Gas	
WGL Holdings, Inc.	

[80] Tr. Oct 8, page 454.
[81] See Order dated April 24, 2002, ¶ 15.
[82] Exhibit 4, page 13.
[83] Exhibit 15, page 11.
[84] Id., page 12.
[85] Exhibit 4, JSG-2, Schedule 2, page 1.

Five of Gaske's six companies are also represented on King's list. The exception is Keyspan Corporation, which King excluded because that company's gas distribution operations accounted for only about half its revenue.[86] The addition of six more gas distribution companies in King's sample provides a broader and therefore more representative group of companies from which to draw indications as to the cost of equity for gas distribution operations.

3. Forecast of Next Year's Dividends

Both witnesses used a forecast of next year's dividends to identify the dividend yield portion of the DCF formula, and both witnesses based this forecast on a percentage of the 5-year annual earnings growth rate predicted by Zacks Investment Research, Inc. Only the percentage differed. King used a factor 1.5 on the assumption that the next dividend increase would be randomly distributed over the coming year.[87] Gaske used a 1.625 inflator of the growth rate and argued that King's factor does not reflect the present value of next year's dividends and dividend increases.[88] King responded that if he were to reflect the time value of next year's dividend, rather than simply its numerical value, he would reduce the inflator, not increase it as Gaske has done.[89]

In any case, the effect on the final DCF results of this .125 difference in the inflator for the next year's dividend is negligible.[90]

4. Timing of Analysts' Forecasts

One difference between the two witnesses' analyses that was probably unavoidable was their timing. Gaske's testimony was filed on April 12, 2002, concurrently with MDU's initial application for an increase in its gas rates. The record does not disclose when Gaske prepared his testimony, but presumably it was in the months immediately preceding the application, which would be February and March of

[86] Exhibit 17.
[87] Tr. Oct 7, page 188.
[88] Exhibit 24, page 14.
[89] Tr. Oct. 7, pages 188-189.
[90] Id.

2002. This would be consistent with the fact that the latest month shown on Gaske's presentation of bond yields is January 2002.[91]

King filed his testimony on August 30, 2002, so his information on such factors as share prices and investor expectations was gathered approximately six months after Gaske's.

It is not clear how these differences in timing affect the results of the respective analyses. For example, Gaske reported Zacks' consensus 5-year earning growth forecast for the LaClede Group as 12.0 percent.[92] By the time King prepared his testimony, that forecast had dropped to 4.25 percent.[93] On the other hand, Gaske's forecast growth rate for AGL Resources was 7.03 percent, while that reported by King was 11.42 percent. Whatever the effect, King's analysis reflects much more recent data than Gaske's and should be given greater weight.

5. Procedure for Computing Retention Growth

Both witnesses used the same two methods for forecasting the growth component of the DCF formula. One was Zacks Investment Research's consensus forecasts of 5-years' earnings growth. The other was the rate at which the retention of earnings would permit the book value of each share to increase over the coming five years. Both witnesses used Value Line's company reports for this procedure, although again King had access to later reports than did Gaske.

The only methodological difference between the two analyses was King's inclusion of a factor to account for the sale of new stock at market values higher than book value. This inclusion added 100 basis points to the earnings retention growth model developed by King.[94] Although Gaske did not include this factor in his retention growth model, he did not object to King's use of it.

6. Presentation of the DCF Results

Gaske purported to perform three different DCF analyses of his proxy group of companies. One of these analyses, the "basic DCF," was identical to King's "classic

[91] Exhibit 4, JSG-2, Schedule 1, page 2.
[92] Id., page 5.
[93] Exhibit 15, page 15.

DCF" analysis. Both involved combining the forecast dividend yields with Zacks' 5-year consensus forecasts of earning growth.

While the methods were the same, the results were quite different. Gaske's six-company proxy group yielded a median basic DCF return, prior to flotation costs, of 12.61 percent and a mean return of 12.95 percent.[95] King, applying exactly the same procedure to his comparison group of 11 companies, found the average (mean) to be 11.29 percent.[96]

For his other application of the DCF approach, King added the dividend yield to the growth rate indicated by the earnings retention growth model for each of his 11 comparison companies and found the average to be 12.18 percent.[97] Had Gaske done the same thing, he would have added his average dividend yield of 5.14 percent[98] to his retention growth estimate of 5.5 percent[99] for a DCF return indication of 10.64 percent.

Gaske did not. Instead, he diluted his retention growth rate by mixing it one third, with two-thirds represented by the Zacks' 5-year earnings forecasts. The result, not surprisingly, was quite close to the "basic" DCF indications. The median of his "Second-Stage Retention Growth DCF Calculation" was 11.94 percent, the mean 12.25 percent.

Both witness presented a third version of the DCF analysis, but neither should be given any weight. Gaske put forth what he called his "primary" DCF calculation. This was no calculation at all, but merely the adoption of a range of growth estimates pulled from thin air with no support in the data Gaske presents. The range was 6.75 percent to 7.75 percent, asserted by Gaske to have been based on such factors as the 5.5 percent growth in nominal Gross Domestic Product during the past decade, the expected demand growth for natural gas, and investor expectations.[100]

None of these considerations support a growth forecast in the range of 6.75 percent to 7.75 percent. The bottom of this range is well above the 5.5 percent GDP growth cited by Gaske, as well as the 5.5 percent growth indicated by his own earnings

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[94] Id., page 20.
[95] Exhibit 4, JSG-2, Schedule 2, page 7.
[96] Exhibit 15, page 18.
[97] Id. page 20. King refers to this model as the "book value growth" procedure.
[98] Exhibit 4, JSG-2, Schedule 2, page 2.
[99] Id.
[100] Id., pages 20-21.

retention calculation. The top of the range is above the 7.56 percent growth rate predicted by Zacks for the six proxy group companies used by Gaske.[101] This "primary" DCF analysis is without foundation in the data, and it is clearly biased upward.

King also presented a third DCF calculation, but he subsequently discarded it. Noting that analysts' reports always include considerable historical data and therefore might regard history as relevant, King calculated a growth factor for each of his 11 comparison companies based on the each company's historical earnings growth between 1997 and 2001. While the average DCF indication of 11.72 percent might appear reasonable, the variation among the individual company observations was so great as to provide little or no probative value – as King conceded in his testimony.[102]

In presenting his DCF returns, King went one step further than Gaske, and that was to provide his estimate of the DCF return requirements of each of his comparison companies. He did not use a mechanical formula because, as he conceded in his testimony, precision is impossible.[103] He described his procedure orally at the hearing as follows:

> ...what I have done in each case is taken the classic DCF return, which is probably the best estimator, and then turned and looked at the retention growth method. If the retention growth looks like it's totally out of whack with the forecast, and in some cases they are – simply no way that the company could be growing as fast or as slowly as the investor survey shows – I modified that classic DCF in the direction of the retention growth.[104]

[101] Id., JSG-2, Schedule 2, page 7.
[102] Exhibit 15, pages 22, 23.
[103] Id., page 24.
[104] Tr. Oct. 7, page 190.

The results of this procedure were as follows:[105]

	Classic	Book Value Growth	King DCF Return
Atmos Energy Corp.	12.06%	14.42%	12.5%
AGL Resources	16.67%	11.53%	14.0%
Cascade Natural Gas Corp.	10.25%	15.11%	11.0%
LaClede Group, Inc.	10.29%	11.23%	10.5%
NICOR, Inc.	11.51%	15.96%	12.0%
Northwest Natural Gas Co.	10.65%	10.12%	10.5%
People's Energy Corp.	13.13%	12.07%	12.5%
Piedmont Natural Gas Co.	9.42%	11.24%	10.0%
South Jersey Industries, Inc.	8.15%	12.57%	11.0%
Southwest Gas	10.52%	8.53%	10.0%
WGL Holdings, Inc.	8.99%	11.21%	9.5%
Average	**11.29%**	**12.18%**	**11.23%**

In his rebuttal testimony, Gaske made much of the fact that the average of King's selected DCF results was lower than the average of either his classic or his book value growth results.[106] That is the mathematical consequence of King's shrinking of the range of observations. King reduced the effect of the "outlier" highest and lowest observations. In absolute terms, the outliers on the high side diverge more from the mean than those on the low side, even when their percentage difference from the mean is the same.

This mathematical distortion can be avoided by focusing on the median observation of each series, that is, the observation where five values are higher and five are lower. The classic DCF median return is 10.52 percent, the median of the book value growth series is 11.53 percent, and the median of King's selected DCF returns is 11.0 percent. Additionally, it should be noted that in arriving at his final DCF recommended returns, King adjusted seven of the classic returns upward and only four downward.

On rebuttal, Gaske submitted two mechanical recalculations of King's DCF results, one using a 33%/67% weighting of the book value growth and Zacks' forecasts, the other using a 50%/50% weighting. Both yielded average returns considerably

[105] Exhibit 15, pages 23, 24.
[106] Exhibit 24, page 10.

higher than King's 11.23 percent.[107] In performing these calculations, however, Gaske excluded WGL Holdings, ostensibly because, with 74.6 percent of its revenue from regulated gas distribution, it falls outside King's 75 percent criterion.[108] As Gaske admitted on cross-examination, 74.6 percent rounds up to 75 percent.[109] His exclusion biased the results upward because, at 8.99 percent, WGL Holdings' classic DCF return was the lowest in King's comparison group. Moreover, Gaske never explained why his mechanical weightings of King's DCF results were more accurate or valid than King's analysis.

7. Adjustment of Comparison Company Results for MDU's Risk

Possibly the starkest disagreement between Gaske and King relates to the final adjustment each witness made to the DCF returns for his comparison companies to reflect the specific risk of MDU's gas distribution operations.

Having found that the DCF cost of capital (inclusive of flotation cost) for his proxy companies was in the range of 12.51 and 13.22 percent, Gaske selected 13.25 percent as MDU's capital cost. This upward adjustment from the range of proxy group returns was based on Gaske's belief that MDU's overall risks are slightly above average relative to the proxy group.[110]

King's adjustment was in the opposite direction. Having found that the average DCF return for his comparison group is 11.23 percent, King picked 10.5 percent for MDU, which is the midpoint between the group average return and the returns for the least risky companies in the group. The basis of this adjustment was King's belief that MDU is less risky than the comparison group.[111]

In his initial testimony, Gaske discussed four types of risk: business risk, regulatory risk, financial risk and market risk. He found that MDU's regulatory and market risks are not significantly different than from those of his proxy group. MDU's

[107] Id., JSG-4, Schedule 1.
[108] Id., page 12.
[109] Tr. Oct. 8, page 455. King also testified that most of WGL's non-regulated revenue is derived from Washington Gas Energy Services, a supplier of gas to the very same customers who receive gas from its regulated subsidiary. Exhibit 15, page 26.
[110] Exhibit 4, page 34.
[111] Exhibit 15, pages 26, 27.

financial risk is slightly greater because the bonds of MDU Resources Group, Inc. are rated slightly lower than the bonds of the proxy companies.[112]

The major difference in risk, according to Gaske, relates to business risk. MDU's gas distribution operations are a fraction the size of the proxy companies. Those companies are between six and 46 times the size of MDU's gas distribution operations. Based on the historical difference between the earned returns of small and large companies, Gaske believes that MDU's smaller size might require a return more than 100 basis points (1.00 percent) higher than the proxy group. In addition, MDU faces the competition of propane and heating oil for new and existing load in its service territory. Furthermore, its rate structure recovers a substantial portion of its fixed costs in the volumetric component of its rates, and MDU does not have a weather normalization adjustment mechanism. On this basis, Gaske concluded that MDU's North Dakota gas distribution operations face somewhat greater overall business risks than the typical company in his proxy group.[113]

King based his conclusion that MDU's gas distribution business is less risky than his comparison group on two facts. First, unlike eight of the 11 comparison companies, MDU's gas distribution operations have no non-regulated business activities. Second, MDU's equity ratio is higher than all but three of his comparison companies, suggesting a lower level of financial risk. He argued that a good case could be made for setting MDU's rate of return at the bottom of the scale of DCF returns for the comparison companies. However, in light of the possibility that the return set in this case may be in effect for an extended period into the future, he selected the midpoint between the lowest returns in his comparison group and the average.

In his rebuttal testimony, Gaske argued that King had failed to demonstrate any strong correlation between equity return and the equity proportion or the percent gas distribution revenues in his comparison companies. Gaske presented two correlation studies of these variables.[114] One showed a weak, but measurable correlation between

[112] Exhibit 4, pages 29.31.
[113] Id. pages 27-29.
[114] Exhibit 24, pages 22-26.

the percent equity in capital structure and King's estimates of DCF returns. The other showed no correlation between equity return and percent gas distribution revenues.[115]

In his oral testimony at the hearing, King conceded that neither of the two risk factors cited in his testimony are predictors of relative risk, but both are elements of relative risk. A high equity ratio is an indicator of low financial risk, and MDU's equity ratio is about equal to the highest of the equity ratios of within his comparison group.[116] The relationship between financial risk and capital structure, which King cites in this portion of his testimony, was also discussed in Gaske's initial testimony at some length.[117]

King noted that another element of risk is the amount of non-regulated activity. Regulated activities are less risky than non-regulated activities. When regulated earnings are short, MDU can come to the Commission for an increase in rates. If the Commission grants the rate increase, there is no question whether MDU can collect the additional revenue because of its monopoly status. That is not true of non-regulated activities, which by definition do not have the security of revenue recovery that low-risk regulated activities have.[118]

King also cited two further reasons that MDU gas distribution operations have lower risk than many of his comparison companies. Gas companies operating in warmer climates face competition from electric heating that MDU, operating in a cold climate, does not encounter. He testified that in Washington, DC, the Washington Gas Light Company has lost two-thirds to three-quarters of the commercial load to the electric company. For residential customers, heat pumps can combine heating with air conditioning and so compete with gas.[119] King stated that stand-alone heat pump units that do not draw heat from groundwater will not work in North Dakota's climate because they have to be supplemented with electric resistance heating when temperatures fall below about 45 degrees Fahrenheit.[120]

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[115] Id., JSG-4, Schedule 2.
[116] Tr. Oct. 7, page 190.
[117] Exhibit 4, page 30.
[118] Tr. Oct. 7, page 191.
[119] At the hearing, Gaske submitted Exhibit 35, which contained some Washington Gas Light Company Internet advertisements for gas heating. These advertisements confirm that Washington Gas faces stiff competition from electricity for its residential heating load.
[120] Tr. Oct. 7, page 218

The other difference cited by King relates to the intrusion of gas suppliers into the retail gas market. Some of his comparison companies (he cited Washington Gas and Atlanta Gas Light Company) are required to deliver the gas of independent suppliers. The extreme example is Atlanta Gas Light, which no longer buys gas on behalf of its customers. Instead, merchant gas suppliers buy the gas, and Atlanta Gas Light delivers it to end users on behalf of the suppliers. He testified that Atlanta Gas went from some 600,000 customers to 11. When one of these gas suppliers went bankrupt, Atlanta Gas was "stiffed" for several million dollars.[121]

In another example cited by King, Washington Gas has lost two thirds of its commercial load to competitive suppliers. The suppliers have failed to acquire the transportation capacity that Washington Gas had maintained to serve those lost customers, and there is now a risk that in a cold winter, the suppliers will not be able get the required gas to Washington.[122]

King observed that MDU does not have anything like the active competition from suppliers that larger companies serving larger service territories have. It therefore does not face the severe business risks associated with these suppliers.[123]

As regards the alleged risk of small company operations, King suggested that Gaske has conducted an apples-and-oranges comparison. He has compared the risk properties and required returns of large companies with those of small, stand-alone companies. That is not the proper comparison. The relevant objective in this case is to find the risk characteristics the gas operations of a large company. Being part of a large company provides the security of greater financial strength and also diversification of financial resources.[124]

MDU's North Dakota gas distribution operations are not a small, stand-alone company, as are the small companies from which Gaske derives his 100 basis point small-company risk adder. MDU's North Dakota gas distribution operations are merely one part of the overall business of MDU Resources Group, Inc. That company is well within the size range of the companies in both Gaske's and King's comparison groups.

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[121] Tr. Oct. 7, page 193.
[122] Id.
[123] Id.
[124] Id., pages 193, 194.

While MDU's gas distribution operations are small, they have a lower financial risk than do most of King's comparison companies by reason of a high equity ratio. They have no risky, non-regulated activities, as do most of the comparison companies. While MDU faces competition from propane and oil, as do virtually all gas companies, it does not confront effective competition for its heating load from electricity, as do the comparison companies that operate in warmer climates. Finally, MDU does not have the intrusion of independent gas suppliers into its retail market in anything like the degree that some of the comparison companies have. For these reasons, King's conclusion that MDU has somewhat less overall risk than his comparison companies is altogether reasonable.

a. Gaske's "Benchmark Analyses"

Gaske presented two types of "benchmark analyses." In one series, he added the historical differences between Treasury bonds and corporate bonds, on the one hand, and earnings from the common stock of small and, alternatively large companies, on the other. The other benchmark analysis was to identify the recent earned return on book value of S&P's 500 companies and on Value Line's industrial companies. The results of these benchmark analyses are as follows:[125]

Risk Premium Return Based on:	
- U.S. Treasury Bonds	
v. Large Companies	13.3%
v. Small Companies	20.2%
- Corporate Bonds	
v. Large Companies	14.8%
v. Small Companies	22.2%
Alternative Investments	
- S&P 500	21.5%
- Value Line Industrials	29.4%

It is not evident that Gaske used these results in setting his rate of return. At the conclusion of his testimony he appears to conclude from these tests that his 13.5

[125] Exhibit 4, page32.

percent cost of capital, derived from DCF results, is quite conservative relative to these benchmark results. Whatever their use, these results should be disregarded, because their conceptual basis is fatally flawed and the risk premium observations are without value statistically.

Gaske's risk premium analysis purports to measure the required return to equity by adding the historical difference in experienced earnings from stocks and bonds to the current levels of bond yields. These historical differences, as measured by Ibbotson Associates, go back to 1926.[126] The theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials.

King observed that this theory is a statement of faith, not experience, and it defies logic. If investors? short-term expectations are continually being frustrated (as has been the case during the last year), what possible logic supports the proposition that the sum of those failed short-term expectations represents a valid long-term representation of their expectation? King further argued that it is untrue that the differential in required returns between bonds and stocks is fixed and unchanging, as this theory postulates. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.[127]

Quite apart from these conceptual failing, the theory fails statistically. Gaske introduced Exhibit 34, which shows annual returns to large company stocks, small company stocks and long-term corporate bonds. It also shows their differences. The standard deviation every one of these series is greater than the mean of the observations. The means therefore lack statistical significance and are useless as a predictive tool.

At the conceptual level, Gaske's alternative equity investment analysis fares no better. Gaske purports to demonstrate that MDU should be allowed a high return by observing that the returns to book equity on the S&P 500 companies from 1977 to 2000

[126] Id., pages 22-24.
[127] Exhibit 15, pages 31, 32.

have averaged 21.47 percent. He also observes that the book equity returns to 746 industrial, retail and transportation companies included in The Value Line Investment Survey have ranged from 27.57 percent to 31.75 percent over the five years 1996-2000. He argues that the average of 29.4 percent, along with the return of 21.47 percent experienced by S&P's 500 companies, suggests that the 13.25 percent he proposes for MDU is quite low.[128]

King argued that these comparisons are utterly irrelevant. He pointed out that investors in unregulated industrial, retail and transportation firms have no access to book equity value. The only value that is meaningful for investors in such firms is the market value. That is what an investor must pay to acquire the stock, and conversely, the value an investor will receive by selling the stock. Book equity value in an industrial firm is a purely historical number representing the dollars of original investment in equity capital contributed to (or retained by) MDU. It has little relevance to the current market value, even for fairly capital-intensive firms. Since most stocks sell well above their book value, the return that is accessible to investor is considerably less than the 20 to 30 percent noted by Gaske.[129]

King noted that book values are relevant for regulated utilities because regulation makes them so. Regulation sets the earnings allowance for such companies relative to a rate base reflective of the book value of the capital invested utility operations. This condition does not apply to industrial firms.[130]

b. King's Risk Premium Test

In contrast to Gaske, King did not attempt to find any absolute value of equity return using the risk premium approach. He agreed that equity investment, being inherently more risky than debt, requires a higher return. But rather than attempt the difficult (and arguably impossible) task of measuring that risk premium, he looked to the trends in bond yields in comparison to past North Dakota Commission findings of equity return to gas companies. If it appears that bond yields have increased, but he has recommended a reduced return to equity, then there may be reason to question his

[128] Exhibit 4, pages 24-26.
[129] Exhibit 15, page 33.
[130] Id.

finding. On the other hand, if his proposed equity return tracks with the changes in bond yields, then there is at least a "sanity check" on the propriety of his finding.[131]

King identified three gas cases during the past 12 years in which the Commission had found a rate of return to equity. He compared those rates of return with the then-current yields on 10-year Treasury bonds and Aaa Corporate bonds. He then identified the current (that is, August 2002) bond yields. The results of his research are as follows:[132]

Case	Utility	Date	ROE Allowed	10-Yr Treas.	Aaa Corporate
399-90-820	MDU	July 30, 1991	12.0%	8.27%	9.00%
400-95-559	NSP	June 7, 1996	12.0%	6.91%	7.71%
400-00-521	NSP	June 27, 2001	11.5%	5.28%	7.18%
399-02-183	**MDU**	August, 2002	**10.5%***	4.35%	6.45%

While King's recommended equity return is lower than any that have been approved for gas utilities in the past 12 years, this result is justified by the evidence of lower overall capital costs. Those lower capital costs are demonstrated by a dramatic reduction in bond yields relative to their level when the previous gas rate cases were decided. For this reason, King's recommended equity return of 10.5 percent is reasonable.

IV. COST ALLOCATION AND RATE DESIGN

A. CLASS COST OF SERVICES STUDY

A class cost of service study is an analysis of the embedded or incremental costs of providing utility services to the customers or classes of customers that either cause these costs, or to whom these costs can reasonably be allocated. The purpose of a class cost of service study is to provide an indication of what it costs to provide utility service to each customer class. In prior rate applications the Commission has used

[131] Id., page 30.
[132] Id., page 31.

class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers.[133]

MDU Witness, Tamie Aberle, sponsored an embedded cost of service study for the year ended December 31, 2001.[134] This study allocated all of MDU's recorded distribution, general and gas-related common plant among seven categories of customers:

- Residential
- Firm General
- Air Force
- Small Interruptible Sales
- Small Interruptible Transport
- Large Interruptible

The costs allocated to the respective customer classes were in turn subdivided into three categories:

- Capacity related costs that vary with the amount of gas sendout on the peak days of the year. Examples include the sizing of distribution mains and meters to account for the maximum volume of gas handled on any one day.
- Throughput related costs that vary with the total amount of gas distributed throughout the year. Uncollectible accounts is a good example of this type of cost.
- Customer related costs that vary with the number of customers. Examples include the cost of meters, services and billing.

The only controversy relating to this cost of service study concerned the allocation of the cost of mains. Mains constitute 39.1 percent of MDU's gas distribution plant, but their relevance exceeds even this percentage.[135] That is because general and common plant, which account for another 20 percent of total plant, are allocated as overheads to the direct investment, of which mains are the largest component.

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[133] See, for example, Case No. PU-399-90-820, Order dated July 30, 1991, ¶¶56-63; Case No. PU-400-95-559, Order dated August 7, 1996, ¶¶35-43.
[134] Exhibit 2, Statement M.
[135] Exhibit 15, page 38.

In its initial cost of service study, Statement M of Exhibit 2, MDU allocated mains 64 percent on the basis of peak two-day throughput during the year and 36 percent on the basis of the number of customers.

King objected to the allocation or a portion of mains costs on a customer count basis. The arguable justification for doing so is that the purpose of the mains system is to reach customers, and that when more customers are added, the mains system has to be extended. King argued that this is true only at the very edges of the system, where gas mains are being extended to serve new developments in previously unserved areas. Even then, the added cost of mains for new customers can vary dramatically depending on the location of those customers.[136]

King suggested that there is another purpose of mains, which is to deliver gas. He argued that the value derived and the benefits received from the mains system are more related to the amount of gas delivered than to the number of customers. One customer receiving twice as much gas as another customer enjoys exactly twice the BTU heating content. The two cannot be equated in terms of benefit received, yet that is what a customer allocation of mains does. He illustrated his point by using the example of a section of main that changes the number and makeup of customers over a period of several years, but the amount of gas delivered remains the same. The weighting of that main in the cost of service study would change under a customer allocation, but it would remain the same (although shifted among customer classes) if the allocation is made on the basis of annual throughput.[137]

King therefore requested MDU to conduct an alternative study that allocates half the mains cost according to the classes' two-day peak throughput and half on the basis of annual throughput. This study was attached to King's testimony.[138]

On rebuttal, Aberle objected to King's revisions, arguing that main additions are not made only on the edges of the system to provide new service to developments, but are also required to enhance system integrity and maintain pressure throughout the system as customer additions are made. She objected that heating content has no impact on the cost of the mains system. She also objected to the use of a peak-day

[136] Id., page 39.
[137] Id. page 39.
[138] Id., CWK-7.

allocator that assigns costs to the interruptible class and a throughput allocator that assigns costs to the transmission customers. She argued that both of these allocations violate practices previously approved by the Commission.[139] She submitted yet a third cost of service study, one which allocates mains based 50 percent on throughput at the distribution level and 50 percent on peak day use by firm customers.[140]

The results of the three cost of service studies are as follows:

	Statement M	King CWK-7	Aberle TAA-4
Residential	3.083%	7.731%	6.367%
Firm General	3.998%	2.161%	1.106%
Air Force	50.281%	3.502%	69.369%
Small Interruptible Sales	83.992%	38.040%	40.905%
Small Interruptible Transport	169.437%	48.490%	57.738%
Large Interruptible	78.644%	-0.673%	27.320%
Total North Dakota	6.439%	6.442%	6.442%

As among these three studies, the least credible is the Statement M study. Aberle is no doubt correct that the existing mains system must be expanded from time to time to accommodate new customers. She did not mention that this expansion may also be due to increased demand from existing customers. It is not the number of customers that drives these enhancements, but their peak demands on the system. This effect is reflected in the peak two-day allocator used in all three studies. The basic layout of the existing mains system is there to deliver gas to customers. Admittedly, neither the amount of gas delivered nor the number of customers determines the size, hence the cost, of this basic layout of mains. In the absence of a cost-causing element, the next best alternative allocator is one that which reflects the value of the service provided. The value of gas service is best measured by the total amount of gas delivered through the distribution system.

As between CWK-7 and TAA-4, it must be acknowledged that Aberle's allocators are more appropriate. Accordingly, Staff recommends that TAA-4 be adopted as the basis for cost allocation among customer classes. The principal effect is that the Air Force and the Large Interruptible classes are shown to have much higher rates of

[139] Exhibit 26, pages 3, 4.
[140] Id., TAA-4.

return than the two principal classes, residential and firm general. In all three studies, the small interruptible customers generate a much higher than average rate of return.

B. RATE DESIGN

In its initial application, MDU made a number of rate design proposals, as follows:[141]

- Increase residential and firm general service rates by 4.6 percent, reduce the small interruptible class rates by 4.1 percent, and leave the Air Force and large interruptible rates unchanged;
- Separate the commodity rate into a Distribution Delivery Charge and a Cost of Gas charge, eliminating the Purchased Gas Cost Adjustment;
- Eliminate the declining block rate form from the commodity charges and substitute a flat per-dekatherm ("dk") rate;
- Change the customer, or "Basic Service Charge" from a monthly to a daily charge;
- Increase the Basic Service Charges by very large percentages, for example, the residential charge increases from $6.50 to $11.70, the small firm service charge from $8.50 to $24.00 and the large firm service charge from $17.00 to $51.00.
- Eliminate the residential seasonal rate;
- Increase the penalty for failure of interruptible customers to interrupt from $10 to $50 per dk;
- Increase the return check fee to $20;
- Increase the reconnection fees for seasonal customers to match the avoided Basic Service Charges;
- Increase the reconnection charge for disconnected customers for nonpayment to $30;
- Modify the Firm Gas Extension Policy Rate 120 and 124 to reflect MDU ownership of all prospective service lines.

King recommended that the Commission accept a number of these proposals regardless of whether MDU's overall revenue is increased, decreased, or remains unchanged. These consensus proposals are as follows:[142]

- The commodity rate should be separated into two clearly distinct rates, the Distribution Delivery Charge and the Cost of Gas Rate.

[141] Exhibit 9.
[142] Exhibit 15, page 43.

- The declining block rates should be eliminated, and the revenue collected through the higher initial block rates should be reallocated to the Basic Service Charge.
- The residential seasonal rates should be eliminated, since there are no customers on these rates.
- Penalties for failure to interrupt should be increased, since MDU apparently believes that the current penalties are not sufficient to ensure that interruptible customers respond to their calls for interruption or curtailment.
- The reconnection charges for seasonal customers should be adjusted to match the higher Basic Service Charges resulting from the elimination of declining commodity blocks.
- MDU's proposed modifications to the line extension policy should be adopted.

King supported MDU's proposal to eliminate declining block commodity rates on the grounds that this rate structure implicitly encourages customers to use more gas, and it thereby discourages conservation. To the extent that it collects fixed customer costs in the commodity rate, it misstates the cause of the costs. Declining block rates also allow customers who use minor amounts of gas for non-heating purposes to escape the cost of providing the basic elements of service to them.[143]

Using MDU's billing unit counts for the year 2001, King calculated the revenue-neutral increase in monthly customer charges that would result if the present declining block rate structure were eliminated from each rate schedule, as follows:[144]

	Present	Proposed
Small Residential	$6.50	$8.43
Large Residential	$13.00	$15.31
Small Firm Service	$8.50	$14.34
Large Firm Service	$17.00	$45.16

King also recommended that the Commission consider MDU's proposal to convert the customer charges from monthly to daily charges. While this proposal simplifies the calculation of the charge when customers are taking gas for only part of a month, it may not be well received by the average customer as a way of charging for

[143] Id., page 44.
[144] Id., CWK-8.

service. At the hearing, Commissioner Wefald expressed some concern in this regard.[145]

King recommended that the Commission not accept MDU's proposal to increase the reconnection charge for discontinued service to $30. While MDU claimed that this is a cost-based rate, King suggested that there is a legitimate public policy reason for not increasing this rate. The customers to whom this charge applies are almost certainly the lowest income customers. Otherwise, they would not have been disconnected. Since they have to pay their arrearages anyway, they are likely to be suffering some difficulty getting reconnected. To impose on them yet more cost, such as an increase in the reconnection fee, might prevent some of these customers from obtaining vital utility service.[146] MDU did not respond to King's recommendation.

King also took issue with MDU's proposed distribution of any rate increase among customer classes. MDU proposed that residential and firm general service customers receive a rate increase of 4.6 percent, that the Air Force and large interruptible customers receive no increase, and that the small interruptible class receive a reduction of 4.1 percent.[147] King pointed out that the Commission's past practice has been to recognize differences in class rates of return by approving lower rate increases to classes with the highest rates of return. It has not approved rate reductions to some classes when most customers are suffering rate increases.[148] All classes, regardless of their rates of return, should receive some rate increase if overall revenues are increased and a rate reduction if overall revenues are reduced.

King had similar misgivings about MDU's proposal to increase customer charges dramatically, even for the classes for which it was proposing rate reductions or no rate increases. MDU witness, Russell Feingold, argued that shifting revenue recovery from the commodity to the customer component allows MDU to recover much more of its fixed costs on a non-weather sensitive basis. He asserted that this shift also protects customers from the volatility in their gas bills caused by variations in weather.[149]

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[145] Tr. Oct. 7, page 212.
[146] Exhibit 15, pages, 45, 46.
[147] Exhibit 9, TAA-1.
[148] Exhibit 15, page 46, citing Case No. PU-400-00-521, decided June 27, 2001, ¶ 22; Case No. PU-399-90-820, decided July 30, 1991, ¶ 61; and Case No. PU-400-95-559, decided August 7, 1996, ¶¶ 35, 43.
[149] Exhibit 8.

While King understood MDU's rationale, he was concerned with the issue of rate continuity. The sort of changes proposed by MDU will result in dramatically different bills for different types of customers. Very low-use customers might find the increases in their average monthly bills extortionate. Customers accustomed to low gas bills in the summer, that possibly offset high electric bills, could be surprised by the sudden jump in their gas invoices.[150]

King was concerned that customers may also resent high monthly customer charges. When most of the cost of gas is based on the level of gas consumption, customers can avoid high gas bills by conserving gas. But no amount of conservation permits a customer to avoid a monthly customer charge. As long as this charge is not a major portion of the bill, it is likely to be acceptable to most customers. But if it looms as a major element in the cost of gas, customers will come to regard it as a tax from which there is no escape. King suggested that this will not enhance MDU's reputation as a public utility concerned with its customers' good will.[151]

For these reasons, Staff questions the advisability of dramatic increases in the customer charges. If MDU seeks to increase the customer component of its rate schedules, it should do so over a series of rate cases, not as a drastic stoke in a single rate case. In the meantime, customer charges should not be increased by more than twice the overall increase. This ceiling on customer charge increases would be in addition to the increases in customer charges that result from the flattening of the declining block rates. If rates are reduced, the reductions should be flowed entirely into the commodity component of each rate schedule. Customer charges should not be increased when rates are reduced, except to eliminate the declining block feature of the rate schedules.

C. DISTRIBUTION DELIVERY STABILIZATION MECHANISM

If the Commission disapproves of MDU's dramatic increases in customer charges, MDU proposes that, as an alternative, the Commission adopt a Distribution Delivery Stabilization Mechanism ("DDSM"). As described by Feingold, the DDSM

[150] Exhibit 15, page 48.
[151] Id.

would modify the effects of weather variations by adjusting bills for the difference between the actual heating degree days and heating degree days under normal weather. Following a cold winter, the excess in each class's revenue from the greater number of heating degree days would be divided by the projected annual sales volumes in that class and credited to all customers over the following year on a per-dk basis. The revenue shortfall from a warmer than normal winter would similarly be collected through a surcharge to all customers during the subsequent year.[152]

The status of this proposal is unclear. Staff has gone part of the way toward MDU's objective of increasing customer charges. Staff has recommended that the commodity rates be flattened, and the revenue previously collected in the high initial blocks be recovered through increased customer charges. Staff has also recommended that any overall revenue increase be tilted toward the increased customer charges, and any overall rate decrease be flowed through entirely to the commodity charges. At the hearing, Aberle, MDU's rate design witness, could not say whether these concessions to MDU's target of increasing customer charges relative to commodity charges were sufficient to persuade MDU to withdraw the DDSM proposal.[153]

The proposal should be disregarded in any case. As King testified, the value of a weather normalization adjustment should be to ameliorate the volatility in customer bills caused by variations in weather, and particularly the effect of unusually cold winters. In such winters, ratepayers typically experience a "double whammy." First, they consume more gas than usual, which increases their bills even if the price of gas remains the same. Then, because cold winters are usually a widespread phenomenon, the demand for gas is higher across the continent, which means that the price of gas is higher. The result is a further inflation in their bills. Just this sort of inflation occurred across the country during the winter of 2000-2001.[154]

King suggested that MDU's proposal could result in a "triple whammy." If North Dakota experiences an unusually warm winter, and it is followed by an unusually cold winter, ratepayers during the cold winter, already hard-hit, would find themselves

[152] Exhibit 8, page 12-20
[153] Tr. Oct 8., page 498.
[154] Exhibit 15, page 50.

paying a surcharge to make up for the shortfall in revenue collections in the previous year. The effect of MDU's program could be to increase, not decrease the volatility in customers' bills from year to year.[155]

The objection to MDU's proposal is its delayed effect. For a weather normalization adjustment to be beneficial to ratepayers and not just the utility, it must affect their bills when the unusual weather is occurring, not after it has occurred. For this reason, Staff opposes the program offered by MDU.

V. CONCLUSION

Staff requests that the Commission adopt the recommendations presented by Staff witnesses in this case. We believe the adjustments recommended are fair and reasonable to both MDU and its ratepayers.

Dated this 15th day of November, 2002.

William W. Binek
Counsel for Advocacy Staff
Public Service Commission
State Capitol
Bismarck, North Dakota 58505

[155] Id.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

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Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

STAFF PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

November 15, 2002

Appearances

Commissioners: Susan E. Wefald, Leo M. Reinbold, Anthony T. Clark.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy staff.

William P. Pearce, Attorney at Law, 314 E. Thayer Ave., PO Box 400, Bismarck, ND 58502-0400, appearing for Montana-Dakota Utilities Co.

Douglas W. Schulz, Senior Attorney, MDU Resources Group, Inc., PO Box 5650, Bismarck, ND 58506-5650, appearing for Montana-Dakota Utilities Co.

Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

On April 12, 2002, the North Dakota Public Service Commission received an application from Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) to increase its natural gas rates in North Dakota by $2,844,132 annually. MDU's application is based on a calendar 2003 projected test year.

In its application and supporting testimony and exhibits, MDU requests an increase in its rates for gas distribution service of $2,844,132, or approximately 4.1 percent based on a forecast 2003 test year. The primary reasons for MDU's application are increased operation and maintenance costs, depreciation, and taxes other than income, and a higher required rate of return. MDU's requested return on rate base is 11.044 percent, inclusive of a return of 13.25 percent on the 51.687 percent of total capital that MDU asserted to be represented by common equity.

89 PU-399-02-183 Pages: 35

Staff Proposed Findings of Fact,
Conclusions of Law and Order
by Public Service Commission

11/15/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Staff proposes that MDU's test year 2003 rates be decreased by $1,402,000. This reduction is based on a rate of return on rate base of 7.980 percent, inclusive of a 10.5 percent return on 44.55 percent equity proportion of total capital and a much lower cost of debt.

MDU also requested a significant restructuring of its rates, including a separation of gas distribution from gas supply charges, elimination of declining block commodity charges and dramatic increases in customer charges. Additionally, MDU has proposed that all increases be flowed into the firm residential and commercial rate schedules, that no change in rate levels be applied to the Air Force and large interruptible schedules, and that the small interruptible class should receive a rate reduction.

On April 24, 2002, the Commission suspended MDU's rates filed with its Natural Gas Rate Increase Application. On June 5, 2002, the Commission issued its Notice of Hearing Notice of Public Input Sessions, and Notice of Intervention Deadline. Public input sessions were held via video teleconference on July 15, 2002, in Bismarck, Dickinson, Williston, Minot, Devils Lake, and Jamestown. The technical hearing was held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota on October 7-8, 2002.

The Notice of Hearing specified the issues to be considered at the technical hearing, which are:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

The Notice of Hearing provided that any person wishing to intervene as a party in the proceeding must file a petition for intervention by September 9, 2002. No one petitioned to intervene as a party in the proceeding.

The Commission, having reviewed the evidence in the record makes the following:

Findings of Fact

1. MDU is an investor owned utility company operating as a division of MDU Resources Group, Inc. providing natural gas distribution service in North Dakota.

2. The parties do not dispute the:

- 2003 test year for rate determination.
- Jurisdictional cost of service study.
- 2003 test year for rate base (except accumulated reserve for depreciation)
- Cost of preferred equity.
- Test year revenues.

3. The parties dispute the following issues:

- Cost of capital
- Depreciation
- Bonuses and labor expenses
- Supplemental Income Security Plan
- Rate case expense
- General inflation adjustment for expenses
- Other unadjusted operation and maintenance expenses
- Allocation of cost to customer classes
- Rate design
- Distribution Delivery Stabilization Mechanism

Test Year Rate Base

4. MDU and Staff are in agreement on the amount of rate base for the 2003 test year with the exception of accumulated reserve for depreciation. The staff adjustment for this issue is affected by a staff adjustment to depreciation expense of $2,172,000. This adjustment to depreciation expense increases rate base by $1,086 for the 2003 test year.

5. The Commission finds the following 2003 test year rate base:

Average Rate Base	**(Thousands)**	**(Thousands)**
Description	2003 Company Test Year	Staff Adjustments
Plant in Service	$72,793	
Accum. Res. for Depreciation	$49,356	$1,086
Avg. Net Plant in Service	$23,437	
Constr. Work in Progress	$0	
Materials & Supplies	$439	
Fuel Stocks	$22	
Prepayments	$84	
Other	$44	
Accum. Def. Income Taxes	($3,842)	
Accum. Invest. Tax Credits	($231)	
Customer Advances	($272)	
Average Rate Base	$19,681	$20,767

Cost of Capital

6. MDU proposes a post-tax rate of return of 11.044 percent, which includes a 13.25 percent return on the 51.687 percent of its capital represented by common equity. Staff has recommended a return of 7.98 percent, including a 10.5 percent return on 44.55 percent of MDU's capital that it finds to be represented by common equity. Using MDU's 39.61 percent federal and state income tax rate, the pre-tax rates of return can be calculated as follows:

MDU:

	Cost	**Proportion**	**Post-Tax**	**Tax**	**Pre-tax**
Long-term Debt	9.180%	43.039%	3.951%		3.951%
Preferred Stock	4.662%	5.274%	0.334%	0.090%	0.244%
Common Equity	13.250%	51.687%	9.562%	2.713%	6.849%
Total		100.000%	13.847%		11.044%

Staff:

	Cost	Proportion	Post-Tax	Tax	Pre-tax
Long-term Debt	6.167%	47.92%	2.96%		2.96%
Short-term Debt	4.542%	2.78%	0.13%		0.13%
Preferred Stock	4.630%	4.75%	0.31%	.09%	0.22%
Common Equity	10.50%	44.55%	6.53%	1.85%	4.68%
Total		100.00%	9.93%		7.98%

7. The difference between the two pre-tax rates of return is 3.917 percent. When applied to MDU's projected test year rate base of $19,681,000, this difference amounts to $771,000. When applied to the Staff's recommended rate base of $20,768,000, the difference comes to $813,000.

8. As demonstrated in the foregoing tables, the Staff differs from MDU with respect to all of the components that make up the rate of return: the capital structure, the cost of debt, and the cost of equity.

Capital Structure

9. Capital structure refers to the makeup of MDU's capital, that is, the mix of debt, preferred stock and equity. Two factors account for the disagreement between Staff and MDU. The first is Staff's inclusion of short-term debt, and the second is Staff's use of year-end 2001 capital structure instead of MDU's projection of its capital structure into 2003.

10. In its initial filing, MDU excluded all short-term debt from its proposed capital structure. Staff's rate of return witness, Charles W. King, testified that the makeup of the capital structure used to develop a rate of return should reflect the nature of the rate base to which that return is applied. If the rate base consists solely of capital investments in plant and equipment financed by long-term debt, preferred stock and equity, then it might be appropriate to exclude short-term debt. But MDU's rate base also includes materials and supplies inventories, fuel stocks, and prepayments, which are short term commitments that will be financed in part with short-term debt. For this reason, he included short-term debt in the capital structure.

11. On rebuttal, MDU witness Craig Keller argued that the items to which King referred, materials and supplies, prepayments and fuel stocks remain relatively constant, not changing materially from one month to another. While classified as short-term assets, they support long-lived assets such as plant, property, equipment and related items. They are therefore financed by long-term debt, according to Keller.

12. At the hearing, King responded to Keller by producing Exhibit 13, which shows the month-to-month amounts of each of the major elements of working capital during the 13 months from December 2000 through December 2001. That exhibit

demonstrates that net working capital varied from negative $53,000 in January to positive $306,000 in July. King concluded that these widely varying amounts would not have been financed with long-term debt.

13. The second difference between the Staff's and MDU's capital structure relates to the use of historical vs. forecast data. King drew the amounts of debt, preferred stock and common equity from Company supplied data for calendar year 2001. He calculated average long-term debt from Exhibit 2, Statement A, page 2; short-term debt from a response to a data request (Exhibit 15, CWK-1); and preferred stock and common equity from Exhibit 2, Statements A and F, page 1.

14. MDU's capital structure was presented on Statement F, page 3 as its projected 2003 capital mix. King objected to this use of a projection on the grounds that it is effectively a creation of MDU that has no basis in any verifiable financial statements.

15. On rebuttal, MDU witness Keller argued that NDCC § 49-05-04.1 permits MDU to use a forecast test year and that Staff witness, Michael J. Majoros, had accepted the 2003 test year as the basis for revenue requirements. Keller argued that failure to use a forecast capital structure would result in a "mismatch" with the rest of the revenue requirement calculation. Keller argued that MDU possesses a financial forecasting system that uses known debt scheduling and projects equity by forecasting earnings and deducting dividends.

16. In his oral direct testimony, King pointed out that MDU had used an historical capital structure in its recent electric case. He argued that the purpose of the future test year is to capture exogenous changes that can be objectively determined, such as inflation or the expansion of the system. By contrast, the capital structure is a creation of MDU's management. There is no way of verifying that it will change in the manner MDU predicts. For this reason, most commissions use recent historical capital structures. Otherwise, MDU has the opportunity to game the regulatory system by projecting a more expensive capital structure, one with greater equity than now exists. A comparison of MDU's 2001 capital structure with its forecast 2003 capital structure reveals that this is exactly what MDU has done in this case. For this reason, an historical capital structure should be used in this case.

Cost of Debt

17. MDU's claimed cost of debt in 2001 is 9.302 percent, and its projected 2003 debt cost is 9.180 percent. These values are calculated on Exhibit 2, Statement F-1, pages 1 and 3. Those pages show only two debt issues, First Mortgage Bonds and Pollution Control Bonds, totaling $133.5 million in 2001 and $132.6 million in 2003.

18. Statement A, pages 11 and 12 of that same exhibit reveals that there is substantially more to MDU's debt than these two issues. As of December 31, 2001, there were $405.2 million in senior notes, $219.7 million in commercial paper, a

revolving line of credit of $25 million, and term credit agreements of $11.8 million. Using the cost values shown on those pages, King calculated that the blended cost of MDU's debt is 6.167 percent, more than 300 basis points lower than MDU proposes.

19. The difference between Staff and MDU revolves around what "the Company" actually is. According to MDU witness Keller, only the First Mortgage and Pollution Control bonds relate to MDU Utilities. All of the other debt pertains to Centennial Holdings, which holds title to the non-regulated operations of the parent Company, MDU Resources Group, Inc. The two sets of debt are not fungible. MDU has no access to Centennial's debt and vice versa.

20. On cross-examination, however, Keller made it quite clear that there is no such entity as the Montana-Dakota Utilities Company. The only legal entity is the parent Company, MDU Resources Group, and only that company can issue debt. Neither the utility operation nor Centennial has any debt in its own right.

21. At the hearing, Keller testified that MDU had attempted to build a "firewall" between the debt of MDU Utilities and that of Centennial. The purpose, he argued, was to protect the utility operations from the effect of default on Centennial's debt. He stated that if Centennial or one of its subsidiaries should go bankrupt, then the bankruptcy judge would not be able to "collapse the corporation" and gain access to the utility's assets. Keller stated that is the reason MDU does not commingle the funds raised for the utility with those raised for Centennial.

22. These are laudable objectives, but it is not clear how far they go. On cross-examination, Keller conceded that if the bankruptcy of either MDU's regulated or its unregulated operations caused the parent to declare bankruptcy, then the bankruptcy court would look at all of MDU's assets to satisfy creditors' claims, including those of the regulated utility.

23. King suggested that there might be another, less altruistic reason for attempting to isolate Centennial's debt from that of the utility operations. It is to ensure that ratepayers pay the very high costs of the First Mortgage bonds and receive no benefit from the Company's other, lower-cost financing resources. While the Company may have written its low-cost financing instruments to direct funds to Centennial and its subsidiaries, that was an artifice to "game" the regulatory system into ascribing only the highest cost debt to regulated service ratepayers. The Company could have used the Centennial funds anywhere had it written the debt instruments differently.

24. In the end, all of MDU Resources' debt is secured by all of MDU Resources' assets. This means that in the end, all of its debt is fungible. For this reason, the Commission finds it appropriate to use the blended cost of all of MDU Resources' debt as the cost of debt for MDU's utility operations.

Cost of Equity

25. MDU's rate-of-return witness, Dr. J. Stephen Gaske, has recommended a return to equity of 13.25 percent. This return was developed using three variants of the Discounted Cash Flow ("DCF") approach, plus a series of "benchmark analyses."

26. For his DCF results, Gaske drew a distinction between "Investor Requirements" and "Cost of Capital" based on his belief that stock flotation costs, equivalent to 4.75 percent of the return, must be included in the latter. Because MDU's parent company, MDU Resources Group, Inc., is heavily engaged in non-regulated activities Gaske used a "proxy group" of six companies based on Moody's utility series. His DCF results for these companies were as follows:

	Investor Requirements	**Cost of Capital**
Second-stage Retention Growth	11.94%	12.51%
Basic DCF	12.61%	13.21%
Primary DCF	12.63%	13.22%

27. Gaske's benchmark analyses consisted of four risk premium comparisons using historical differences in earned returns to equity from large and, alternatively, small companies relative to current yields on U.S. Treasury bonds and corporate bonds. He also identified the recent returns on per-share book value of S&P 500 corporations and Value Line's list of industrial companies. All of his benchmark indicators were higher than any of his DCF returns.

28. Gaske's final selection of 13.25 percent was based on his belief that the risk of MDU's gas distribution business is slightly higher than that of his proxy group of gas distribution companies. He based this belief principally on the smaller size of MDU relative to the proxy companies.

29. King recommended a very different return to equity: 10.5 percent. King followed most of the same procedures as Gaske using the DCF analyses as the principal analytical tool. Like Gaske, King used a comparison group of gas distribution companies. Also like Gaske, King used a forecast of next year's dividends for the dividend yield portion of the DCF formula. King also used both analysts' forecasts and the concept of earnings retention to calculate the growth component of that formula -- as did Gaske. Finally, both King and Gaske adjusted their final recommendations based on their assessments of the risk of MDU's gas distribution activities relative to that of the comparison companies.

30. The explanation for the dramatic 275 basis point (2.75%) difference between the recommendations of the two witnesses lies in the details of the application of the DCF formula. As used by both witnesses, the DCF formula is the sum of next year's dividend yield on MDU's stock and the expected future growth rate in its dividends and earnings.

31. The differences between the Gaske and King applications of the DCF formula relate to the following elements:

1. Inclusion of flotation costs;
2. Selection of comparison companies;
3. Forecast of next year's dividends;
4. Timing of analysts' forecasts;
5. Computation of earnings retention growth;
6. Presentation of the DCF results; and
7. Adjustment of comparison companies results to reflect MDU's risk.

Flotation Costs

32. Gaske drew a distinction between "investor requirement" and "cost of capital," with the difference being cost of issuing new shares in public stock offerings. Gaske quantified this cost as 4.75 percent, based on a representative sample of flotation costs incurred with 34 new common stock issues by natural gas transmission and distribution companies between 1992 and 2001.

33. King agreed with Gaske that flotation costs should be recovered, but he questioned the propriety of applying a ratio for these costs to the entire amount of common equity. Flotation costs are incurred only when a company issues new stock, and then only when there is a public stock offering. Existing stock incurs no flotation cost, and even new stock incurs no such costs if it is distributed as an employee or shareholder benefit either through options or as bonuses.

34. King noted that the effect of Gaske's flotation cost adjustment is to increase his equity return by 60 basis points, or .60 percentage points. When multiplied by the $1.125 million book equity value of the MDU Resources, Inc., this allowance amounts to $6.75 million annually, which is substantially more than the $5.4 million in flotation costs that the Company has incurred over the past five years.

35. King suggested that if a flotation cost adder is to be used, it should be equal to a reasonable estimate of the annual flotation cost incurrence divided by the entire amount of the Company's equity. In MDU's case, annual flotation costs during the past five years have been about $1.1 million. The Company's total book equity value is $1,125 million, for a flotation cost allowance of 0.1 percent. This amount is so small as to be lost in the rounding. For this reason, he recommended no explicit flotation cost adder.

36. In rebuttal, Gaske distributed an exhibit that purported to demonstrate that failure to include flotation costs in the return of a company's stock trading at book value would result in the dilution of the book value of that company's shares. On cross-examination, however, Gaske admitted that all of King's comparison companies had per-share market values higher than book value, and that when such companies sell new stock,

the effect is to increase book value, not dilute it. On cross-examination, Gaske admitted that his approach to the issue of flotation cost in this proceeding was the same as his approach in Commission Case No. PU-399-01-186[1] involving MDU's electric rates. Gaske also agreed that most regulatory commissions do not allow a flotation cost adder.

37. The Commission rejects Gaske's flotation cost adder.

Selection of Comparison Companies

38. Both King and Gaske acknowledged that the heavy involvement of MDU's parent company, MDU Resources Group, Inc., in non-regulated activities effectively precluded using that company as the basis for finding the return to equity of its gas distribution business in North Dakota. Necessarily, this required the selection of companies whose primary business is gas distribution. Gaske picked six companies from Moody's list of natural gas distribution companies. King chose 11 companies from Value Line's Investment Survey based on the criteria that they must have investment grade bond ratings, total operating revenues over $100 million , and derive more than 75 percent of their revenue from gas distribution services. The two lists are as follows:

King Comparison Companies	**Gaske Proxy Group**
Atmos Energy Corp.	AGL Resources
AGL Resources	Keyspan Corporation
Cascade Natural Gas Corp.	LaClede Group
LaClede Group, Inc.	Northwest Natural Gas
NICOR, Inc.	People's Energy Corp.
Northwest Natural Gas Co.	WGL Holdings, Inc.
People's Energy Corp.	
Piedmont Natural Gas Co.	
South Jersey Industries, Inc.	
Southwest Gas	
WGL Holdings, Inc.	

39. Five of Gaske's six companies are also represented on King's list. The exception is Keyspan Corporation, which King excluded because that company's gas distribution operations accounted for only about half its revenue. We find that King's choice of companies provides a broader and therefore more representative group of companies from which to draw indications as to the cost of equity for gas distribution operations.

[1] Order dated April 24, 2002, ¶ 15

Forecast of Next Year's Dividends

40. Both King and Gaske used a forecast of next year's dividends to identify the dividend yield portion of the DCF formula, and both witnesses based this forecast on a percentage of the 5-year annual earnings growth rate predicted by Zacks Investment Research, Inc. Only the percentage differed. King used a factor 1.5 on the assumption that the next dividend increase would be randomly distributed over the coming year. Gaske used a 1.625 inflator of the growth rate and argued that King's factor does not reflect the present value of next year's dividends and dividend increases. King responded that if he were to reflect the time value of next year's dividend, rather than simply its numerical value, he would reduce the inflator, not increase it as Gaske has done. The effect on the final DCF results of this .125 difference in the inflator for the next year's dividend is negligible. The Commission finds that, since the .125 difference in the inflator for the next year's dividend is negligible, no adjustment will be made for this issue.

Timing of Analysts' Forecasts

41. Gaske's testimony was filed on April 12, 2002, concurrently with MDU's initial application for an increase in its gas rates. The record does not disclose when Gaske prepared his testimony, but presumably it was in the months immediately preceding the application, which would be February and March of 2002. This would be consistent with the fact that the latest month shown on Gaske's presentation of bond yields is January 2002.

42. King filed his testimony on August 30, 2002, so his information on such factors as share prices and investor expectations was gathered approximately six months after Gaske's.

43. It is not clear how these differences in timing affect the results of the respective analyses. For example, Gaske reported Zacks' consensus 5-year earning growth forecast for the LaClede Group as 12.0 percent. By the time King prepared his testimony, that forecast had dropped to 4.25 percent. On the other hand, Gaske's forecast growth rate for AGL Resources was 7.03 percent, while that reported by King was 11.42 percent. We find it is appropriate in this proceeding to use King's analysis that reflects more recent data than Gaske's analysis.

Procedure for Computing Retention Growth

44. Both King and Gaske used the same two methods for forecasting the growth component of the DCF formula. One was Zacks Investment Research's consensus forecasts of 5-years' earnings growth, and the other was the rate at which the retention of earnings would permit the book value of each share to increase over the coming five years. Both witnesses used Value Line's company reports for this procedure, although

again, King had access to later reports than did Gaske. The only methodological difference between the two analyses was King's inclusion of a factor to account for the sale of new stock at market values higher than book value. This inclusion added 100 basis points to the earnings retention growth model developed by King. Although Gaske did not include this factor in his retention growth model, he did not object to King's use of it.

Presentation of the DCF Results

45. Gaske purported to perform three different DCF analyses of his proxy group of companies. One of these analyses, the "basic DCF," was identical to King's "classic DCF" analysis. Both involved combining the forecast dividend yields with Zacks' 5-year consensus forecasts of earning growth.

46. While the methods were the same, the results were quite different. Gaske's six-company proxy group yielded a median basic DCF return, prior to flotation costs, of 12.61 percent and a mean return of 12.95 percent. King, applying exactly the same procedure to his comparison group of 11 companies, found the average (mean) to be 11.29 percent.

47. For his other application of the DCF approach, King added the dividend yield to the growth rate indicated by the earnings retention growth model for each of his 11 comparison companies and found the average to be 12.18 percent. Had Gaske done the same thing, he would have added his average dividend yield of 5.14 percent to his retention growth estimate of 5.5 percent for a DCF return indication of 10.64 percent.

48. Gaske diluted his retention growth rate by mixing it one third, with two-thirds represented by the Zacks' 5-year earnings forecasts. The result was quite close to the "basic" DCF indications. The median of his "Second-Stage Retention Growth DCF Calculation" was 11.94 percent, the mean 12.25 percent.

49. Gaske presented a third version of the DCF analysis. Gaske put forth what he called his "primary" DCF calculation. This was no calculation at all, but merely the adoption of a range of growth estimates pulled from thin air with no support in the data Gaske presents. The range was 6.75 percent to 7.75 percent, asserted by Gaske to have been based on such factors as the 5.5 percent growth in nominal Gross Domestic Product during the past decade, the expected demand growth for natural gas, and investor expectations. None of these considerations support a growth forecast in the range of 6.75 percent to 7.75 percent. The bottom of this range is well above the 5.5 percent GDP growth cited by Gaske, as well as the 5.5 percent growth indicated by his own earnings retention calculation. The top of the range is above the 7.56 percent growth rate predicted by Zacks for the six proxy group companies used by Gaske. This "primary" DCF analysis is biased upward.

50. King also presented a third DCF calculation, but he subsequently discarded it. King calculated a growth factor for each of his 11 comparison companies based on the each company's historical earnings growth between 1997 and 2001. While the average DCF indication of 11.72 percent might appear reasonable, the variation among the individual company observations was so great as to provide little or no probative value -- as King conceded in his testimony.

51. The Commission finds that neither of these third DCF calculations should be given any weight.

52. In presenting his DCF returns, King went one step further than Gaske, and provided his estimate of the DCF return requirements of each of his comparison companies. He did not use a mechanical formula because, as he conceded in his testimony, precision is impossible. He described his procedure orally at the hearing as follows:

> ...what I have done in each case is taken the classic DCF return, which is probably the best estimator, and then turned and looked at the retention growth method. If the retention growth looks like it's totally out of whack with the forecast, and in some cases they are – simply no way that the company could be growing as fast or as slowly as the investor survey shows – I modified that classic DCF in the direction of the retention growth.

53. The results of King's procedure were as follows:

	Classic	Book Value Growth	King DCF Return
Atmos Energy Corp.	12.06%	14.42%	12.5%
AGL Resources	16.67%	11.53%	14.0%
Cascade Natural Gas Corp.	10.25%	15.11%	11.0%
LaClede Group, Inc.	10.29%	11.23%	10.5%
NICOR, Inc.	11.51%	15.96%	12.0%
Northwest Natural Gas Co.	10.65%	10.12%	10.5%
People's Energy Corp.	13.13%	12.07%	12.5%
Piedmont Natural Gas Co.	9.42%	11.24%	10.0%
South Jersey Industries, Inc.	8.15%	12.57%	11.0%
Southwest Gas	10.52%	8.53%	10.0%
WGL Holdings, Inc.	8.99%	11.21%	9.5%
Average	**11.29%**	**12.18%**	**11.23%**

54. Gaske rebutted the fact that the average of King's selected DCF results was lower than the average of either his classic or his book value growth results. This mathematical result stems from King's shrinking of the range of observations. King reduced the effect of the "outlier" highest and lowest observations. In absolute terms, the outliers on the high side diverge more from the mean than those on the low side,

even when their percentage difference from the mean is the same. This mathematical distortion can be avoided by focusing on the median observation of each series, that is, the observation where five values are higher and five are lower. The classic DCF median return is 10.52 percent, the median of the book value growth series is 11.53 percent, and the median of King's selected DCF returns is 11.0 percent. Additionally, it should be noted that in arriving at his final DCF recommended returns, King adjusted seven of the classic returns upward and only four downward.

55. On rebuttal, Gaske submitted two mechanical recalculations of King's DCF results, one using a 33%/67% weighting of the book value growth and Zacks' forecasts, the other using a 50%/50% weighting. Both yielded average returns considerably higher than King's 11.23 percent. In performing these calculations, however, Gaske excluded WGL Holdings, ostensibly because, with 74.6 percent of its revenue from regulated gas distribution, it falls outside King's 75 percent criterion. As Gaske admitted on cross-examination, 74.6 percent rounds up to 75 percent. His exclusion biased the results upward because, at 8.99 percent, WGL Holdings' classic DCF return was the lowest in King's comparison group. Moreover, Gaske never explained why his mechanical weightings of King's DCF results were more accurate or valid than King's analysis.

Adjustment of Comparison Company Results for MDU's Risk

56. King and Gaske disagree about the final adjustment each witness made to the DCF returns for his comparison companies to reflect the specific risk of MDU's gas distribution operations.

57. Having found that the DCF cost of capital (inclusive of flotation cost) for his proxy companies was in the range of 12.51 and 13.22 percent, Gaske selected 13.25 percent as MDU's capital cost. This upward adjustment from the range of proxy group returns was based on Gaske's belief that MDU's overall risks are slightly above-average relative to the proxy group.

58. King's adjustment was in the opposite direction. Having found that the average DCF return for his comparison group is 11.23 percent, King picked 10.5 percent for MDU, which is the midpoint between the group average return and the returns for the least risky companies in the group. The basis of this adjustment was King's belief that MDU is less risky than the comparison group.

59. In his initial testimony, Gaske discussed four types of risk: business risk, regulatory risk, financial risk and market risk. He found that MDU's regulatory and market risks are not significantly different than from those of his proxy group. MDU's financial risk is slightly greater because the bonds of MDU Resources Group are rated slightly lower than the bonds of the proxy companies. The major difference in risk, according to Gaske, relates to business risk. MDU's gas distribution operations are a fraction the size of the proxy companies. Those companies are between six and 46

times the size of MDU's gas distribution operations. Based on the historical difference between the earned returns of small and large companies, Gaske believes that MDU's smaller size might require a return more than 100 basis points (1.00 percent) higher than the proxy group. In addition, MDU faces the competition of propane and heating oil for new and existing load in its service territory. Furthermore, its rate structure recovers a substantial portion of its fixed costs in the volumetric component of its rates, and MDU does not have a weather normalization adjustment mechanism. On this basis, Gaske concluded that MDU's North Dakota gas distribution operations face somewhat greater overall business risks than the typical company in his proxy group.

60. King based his conclusion that MDU's gas distribution business is less risky than his comparison group on two facts. First, unlike eight of the 11 comparison companies, MDU's gas distribution operations have no non-regulated business activities. Second, MDU's equity ratio is higher than all but three of his comparison companies, suggesting a lower level of financial risk. He argued that a good case could be made for setting MDU's rate of return at the bottom of the scale of DCF returns for the comparison companies. However, in light of the possibility that the return set in this case may be in effect for an extended period into the future, he selected the midpoint between the lowest returns in his comparison group and the average.

61. In his rebuttal testimony, Gaske argued that King had failed to demonstrate any strong correlation between equity return and the equity proportion or the percent gas distribution revenues in his comparison companies. Gaske presented two correlation studies of these variables. One showed a weak, but measurable correlation between the percent equity in capital structure and King's estimates of DCF returns. The other showed no correlation between equity return and percent gas distribution revenues.

62. King conceded that neither of the two risk factors cited in his testimony are predictors of relative risk, but both are elements of relative risk. A high equity ratio is in indicator of low financial risk, and MDU's equity ratio is about equal to the highest of the equity ratios of within his comparison group. The relationship between financial risk and capital structure, which King cites in this portion of his testimony, was also discussed in Gaske's initial testimony at some length.

63. King noted that another element of risk is the amount of non-regulated activity. Regulated activities are less risky than non-regulated activities. When regulated earnings are short, MDU can come to the Commission for an increase in rates. If the Commission grants the rate increase, there is no question whether MDU can collect the additional revenue because of its monopoly status. That is not true of non-regulated activities, which by definition do not have the security of revenue recovery that low-risk regulated activities have.

64. King cited two further reasons that MDU gas distribution operations have lower risk than many of his comparison companies. Gas companies operating in warmer climates face competition from electric heating that MDU, operating in a cold climate, does not encounter. He testified that in Washington, DC, the Washington Gas Light

Company has lost two-thirds to three-quarters of the commercial load to the electric company. For residential customers, heat pumps can combine heating with air conditioning and so compete with gas.[2] King stated that stand-alone heat pump units that do not draw heat from groundwater will not work in North Dakota's climate because they have to be supplemented with electric resistance heating when temperatures fall below about 45 degrees Fahrenheit.[3]

65. The other difference cited by King relates to the intrusion of gas suppliers into the retail gas market. Some of his comparison companies (he cited Washington Gas and Atlanta Gas Light Company) are required to deliver the gas of independent suppliers. The extreme example is Atlanta Gas Light, which no longer buys gas on behalf of its customers. Instead, merchant gas suppliers buy the gas, and Atlanta Gas Light delivers it to end users on behalf of the suppliers. He testified that Atlanta Gas went from some 600,000 customers to 11. When one of these gas suppliers went bankrupt, Atlanta Gas was "stiffed" for several million dollars.[4] In another example cited by King, Washington Gas has lost two thirds of its commercial load to competitive suppliers. The suppliers have failed to acquire the transportation capacity that Washington Gas had maintained to serve those lost customers, and there is now a risk that in a cold winter, the suppliers will not be able get the required gas to Washington.[5]

66. King observed that MDU does not the active competition from suppliers that larger companies serving larger service territories have. It therefore does not face the severe business risks associated with these suppliers.

67. King stated that Gaske conducted an apples-and-oranges comparison regarding the alleged risk of small company operations. Gaske has compared the risk properties and required returns of large companies with those of small, stand-alone companies. King says that is not the proper comparison. King states that the relevant objective in this case is to find the risk characteristics of the gas operations of a large company. Being part of a large company provides the security of greater financial strength and also diversification of financial resources. King states that MDU's North Dakota gas distribution operations are not a small, stand-alone company, as are the small companies from which Gaske derives his 100 basis point small-company risk adder. MDU's North Dakota gas distribution operations are merely one part of the overall business of MDU Resources Group. That company is well within the size range of the companies in both King's and Gaske's comparison groups.

68. King stated that while MDU's gas distribution operations are small, they have a lower financial risk than do most of King's comparison companies by reason of a high equity ratio. They have no risky, non-regulated activities, as do most of the comparison companies. While MDU faces competition from propane and oil, as do virtually all gas

[2] At the hearing, Gaske submitted Exhibit 35, which contained some Washington Gas Light Company Internet advertisements for gas heating. These advertisements confirm that Washington Gas faces stiff competition from electricity for its residential heating load.
[3] Tr. Oct 7, page 218
[4] Tr. Oct 7 page 193.
[5] Id.

companies, it does not confront effective competition for its heating load from electricity, as do the comparison companies that operate in warmer climates. Finally, MDU does not have the intrusion of independent gas suppliers into its retail market in anything like the degree that some of the comparison companies have. For these reasons, King's conclusion that MDU has somewhat less overall risk than his comparison companies is altogether reasonable.

69. We agree with King's conclusions and find that MDU has less overall risk than his comparison companies.

Gaske's "Benchmark Analyses"

70. Gaske presented two types of "benchmark analyses." In one series, he added the historical differences between Treasury bonds and corporate bonds, on the one hand, and earnings from the common stock of small and, alternatively large companies, on the other. The other benchmark analysis was to identify the recent earned return on book value of S&P's 500 companies and on Value Line's industrial companies. The results of these benchmark analyses are as follows:

Risk Premium Return Based on:	
- U.S. Treasury Bonds	
v. Large Companies	13.3%
v. Small Companies	20.2%
- Corporate Bonds	
v. Large Companies	14.8%
v. Small Companies	22.2%
Alternative Investments	
- S&P 500	21.5%
- Value Line Industrials	29.4%

71. Gaske appears to conclude from these tests that his 13.5 percent cost of capital, derived from DCF results, is quite conservative relative to these benchmark results. King argued that these comparisons are irrelevant. King argued that these results should be disregarded, because their conceptual basis is fatally flawed and the risk premium observations are without value statistically.

72. Gaske's risk premium analysis purports to measure the required return to equity by adding the historical difference in experienced earnings from stocks and bonds to the current levels of bond yields. These historical differences, as measured by Ibbotson Associates, go back to 1926. The theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials.

73. King observed that this theory is a statement of faith, not experience, and it defies logic. If investors' short term expectations are continually being frustrated (as has been the case during the last year), what logic supports the proposition that the sum of those failed short-term expectations represents a valid long-term representation of their expectations? King further argued that it is untrue that the differential in required returns between bonds and stocks is fixed and unchanging, as this theory postulates. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.

74. King stated that quite apart from this conceptual failing, the theory fails statistically. King referred to Exhibit 34 introduced by Gaske which shows annual returns to large company stocks, small company stocks and long-term corporate bonds, and it also shows their differences. King pointed out that the standard deviation of every one of these series is greater than the mean of the observations. King argued that the means therefore lack statistical significance and are useless as a predictive tool.

75. Gaske purports to demonstrate under his alternative equity investment analysis that MDU should be allowed a high return by observing that the returns to book equity on the S&P 500 companies from 1977 to 2000 have averaged 21.47 percent. He also observes that the book equity returns to 746 industrial, retail and transportation companies included in The Value Line Investment Survey have ranged from 27.57 percent to 31.75 percent over the five years 1996-2000. He argues that the average of 29.4 percent, along with the return of 21.47 percent experienced by S&P's 500 companies, suggests that the 13.25 percent he proposes for MDU is quite low.

76. King argued that these comparisons are irrelevant. He pointed out that investors in unregulated industrial, retail and transportation firms have no access to book equity value. The only value that is meaningful for investors in such firms is the market value. That is what an investor must pay to acquire the stock, and conversely, the value an investor will receive by selling the stock. Book equity value in an industrial firm is a purely historical number representing the dollars of original investment in equity capital contributed to (or retained by) the company. It has little relevance to the current market value, even for fairly capital intensive firms. Since most stocks sell well above their book value, the return that is accessible to investor is considerably less than the 20 to 30 percent noted by Gaske.

77. King noted that book values are relevant for regulated utilities because regulation makes them so. Regulation sets the earnings allowance for such companies relative to a rate base reflective of the book value of the capital invested utility operations. This condition does not apply to industrial firms.

King's Risk Premium Test

78. King did not attempt to find any absolute value of equity return using the risk premium approach. He agreed that equity investment, being inherently more risky than debt, requires a higher return. But rather than attempt the difficult (and arguably impossible) task of measuring that risk premium, he looked to the trends in bond yields in comparison to past North Dakota Commission findings of equity return to gas companies. King stated that if it appears that bond yields have increased, but he has recommended a reduced return to equity, then there may be reason to question his finding. On the other hand, if his proposed equity return tracks with the changes in bond yields, then there is at least a "sanity check" on the propriety of his finding.

79. King identified three gas cases during the past 12 years in which the Commission had found a rate of return to equity. He compared those rates of return with the then-current yields on 10-year Treasury bonds and Aaa Corporate bonds. He then identified the current (that is, August 2002) bond yields. The results of his research are as follows:

Case	**Utility**	**Date**	**ROE Allowed**	**10-Yr Treas.**	**Aaa Corporate**
399-90-820	MDU	July 30, 1991	12.0%	8.27%	9.00%
400-95-559	NSP	June 7, 1996	12.0%	6.91%	7.71%
400-00-521	NSP	June 27, 2001	11.5%	5.28%	7.18%
399-02-183	**MDU**	August , 2002	**10.5%***	4.35%	6.45%

80. We find that, while King's recommended equity return is lower than any that have been approved for gas utilities in the past 12 years, the evidence of lower overall capital costs justifies this result. Those lower capital costs are demonstrated by a dramatic reduction in bond yields relative to their level when the previous gas rate cases were decided. For this reason, we find that King's recommended equity return of 10.5 percent is reasonable.

Depreciation

81. Staff has determined that test year depreciation expense should be reduced by $2,172,000. MDU's current depreciation expense is based on rates developed in a 1991 study performed by Stone & Webster. Staff witness Michael J. Majoros performed a series of studies that suggested MDU's depreciation rates are excessive. First, he found that annual depreciation accruals during the past five years have exceeded utility construction and acquisition by $28.5 million. When common plant construction and acquisition is added, the five-year accruals still exceeded expenditures by $409,000. While it is not the purpose of depreciation to fund construction, this comparison indicates that MDU has obtained substantial cash flow from depreciation. Majoros noted that in *Lindheimer v. Illinios Bell Telephone Company,* 292 U.S. 151 (1934), the

Supreme Court found that excessive depreciation results in the extraction of capital from ratepayers.

82. Majoros next observed that as of the end of 2001, the ratio of depreciation reserve to the original cost of distribution plant came to 70.7 percent. Based on his experience, this level of depreciation reserve is extraordinarily high and suggests that prior depreciation rates have been excessive. Majoros stated that the likely source of these excessive rates is the 140 percent negative salvage adjustment for Account 380 – Services.[6]

83. Majoros adjusted MDU's salvage factors based on an obvious inconsistency between the net salvage assumed in the Stone and Webster study and actual net salvage that MDU has experience during the past five years. The Stone & Webster study developed depreciation rates that resulted in a large recovery of "negative salvage," that is, cost of removal. Specifically, its depreciation rates were designed to recover total gas plant of $102.5 million plus negative salvage (removal) costs of $46.9 million.

84. Majoros found that MDU's actual net salvage experience has been positive. In every year since 1997, MDU has received more in salvage value for its retired gas and common plant than it has paid in removal cost. The total cumulative 5-year net positive salvage receipts for gas plant have amounted to $1,444,452. For common plant, net positive salvage receipts have come to $5,529,260.

85. We find that MDU has experienced positive net salvage.

86. To correct for over-recovery of net salvage, Majoros proposed to adopt the Stone & Webster lives and survivor curves for each account with no net salvage overlay. The account-by-account depreciation rates would thus represent pure depreciation, that is, solely the recovery of original cost. To recognize net salvage, Majoros proposed to deduct from total annual depreciation the average annual amount of net positive salvage for gas plant, plus the net positive salvage of common plant distributed between gas and electric operations based on their respective net salvage amounts. Total depreciation of test year plant would be $1,937,000. The annualized positive salvage offset would be $848,000, for a net test-year depreciation expense of $1,089,000.

87. Majoros noted that, in addition to matching net salvage accruals with actual net salvage experience, his treatment of removal costs conforms with Generally Accepted Accounting Principles ("GAAP") as recently refined in Statement of Financial Accounting

[6] Late Filed Exhibit 1 explains the source of the 140% negative salvage for the Service account. It compares the original cost of retired services with the cost of removal. The composite ratio of original cost to removal cost for all Services removed between 1996 and 2000 is 138%. The removed services date back to 1926, but all of the removal costs were incurred since 1996. The ratio is so high because it compares dollars spent up to 75 years ago with dollars spent only since 1996. The result is a ratio that captures the inflation that has taken place over the past 75 years. When that ratio is then applied to current plant balances to calculate depreciation expense, it effectively projects that same rate of inflation to the end of the current plant's life. Ratepayers are thus being forced to pay for future inflation that presumably will match past inflation. By charging ratepayers now for inflation in the future, this practice fails to recognize the much higher present value of current ratepayer dollars over the Company's future removal cost dollars.

Standards No. 143 ("FAS 143"). That standard, which MDU must adopt this year, requires companies to determine whether they have a legal obligation to retire property and incur the cost of removal or dismantlement. If they do, they must declare the present value of the future "asset retirement obligation" costs as a liability on their books to be amortized over the remaining life of the asset. If they do not, then the American Institute of Certified Public Accounts' Statement of Position on Property, Plant and Equipment would require that these costs be expensed as they are incurred.

88. Majoros testified that MDU has not determined whether it has asset retirement obligations, or what the present value of those obligations might be. For this reason, Majoros' adjustment reflected net salvage experience as a rolling five-year average of actual net removal costs.

89. In rebuttal, MDU witness John A. Jeter, a retired accountant from Arthur Anderson & Co. argued that Majoros had not done a depreciation study, that his review of the current depreciation rates is superficial and contains many errors, and that he has no basis for proposing changes in depreciation rates. According to Jeter, the current depreciation rates are based on a comprehensive study prepared in 1991 and used beginning 1994. He argued that no adjustment of depreciation rates should be entertained until the current depreciation study is completed and an appropriate review has taken place.

90. Jeter asserted that the 1991 depreciation study by Stone & Webster is a much more reliable source of information regarding net salvage than a cursory look at net salvage for all accounts over a five year period. Jeter did not explain the reason, nor did he refute Majoros' observation that the Stone & Webster study had recommended large negative salvage allowances, while MDU's actual net salvage experience has consistently been positive.

91. Jeter's principal response was to attack Majoros' net salvage proposal to adjust overall depreciation by $848,000 based on the past five years' actual experience. He argued that the net salvage amounts used by Majoros varied from year to year and that they reflected the sale of an office building for approximately $4.6 million. Jeter also noted that the electric net salvage amounts – not at issue in this case -- included an insurance adjustment.

92. Jeter also argued that Majoros has allocated common property net salvage based on the direct net salvage amounts of the gas and electric operations, which is not the basis used by MDU. He failed to mention how MDU does allocate these common net salvage amounts. He concludes, "the proposed adjustment is not supported by any evidence and should not be approved."

93. The variability of net salvage from year to year is the very reason Majoros used a five-year average of net salvage experience. Jeter never explained why it should be the basis for rejecting Majoros' adjustment.

94. Jeter's statement that the Majoros depreciation adjustment is "not supported by any evidence" is incorrect. During his re-cross examination, Jeter read the following passage from the NARUC Public Utilities Depreciation Manual, dated August 1, 1996:

> When estimating future net salvage, every effort should be made to ensure that the estimate is as accurate as possible. Normally, the process would start by analyzing past salvage and cost-of-removal data and by using the results of this analysis to project future gross salvage and costs of removal.

95. Majoros analyzed past salvage and cost-of-removal data and found that over the past five years salvage has consistently been greater than cost of removal for both gas plant and common plant. His adjustment reflects that finding.

96. MDU urges the Commission to defer any consideration of depreciation until its new depreciation study, currently being conducted by AUS Consulting, is completed by the end of this year.

97. The Commission believes that no element of MDU's revenue requirement should be exempted from this proceeding. MDU has specifically included depreciation expense in its application and has the burden to prove its case. Therefore, we reject the suggestion that we should decide all issues of MDU's applications with the exception of depreciation. Under N.D.C.C. § 49-05-06, the Commission must decide on the evidence before it by December 12, 2002. MDU's request to defer any consideration of depreciation until the new depreciation study is completed is denied.

98. MDU should not be permitted to continue to charge ratepayers depreciation expense that is excessive. A new depreciation study will not alter the fact that in recent years net salvage has consistently been positive, while the current depreciation rates incorporate a very large allowance for negative salvage.

99. MDU contends that over-depreciation is good for ratepayers. Had Majoros' adjustment been implemented in 1995, MDU's revenue requirement would be higher than it is now. MDU argues that the cumulative effect of overcharging depreciation is to reduce the rate base to the point where the reduction in return and income allowances exceeds the overstated depreciation expense. Jeter multiplied Majoros' $2.172 million depreciation expense reduction by the 8 years since 1995 to derive a presumed increment in the rate base of $17.376 million. He then calculates that at MDU's proposed 11.044 percent return and 39.61 percent tax rate, the revenue requirement increase from this rate base increment would be $3.2 million, which is more than Majoros' depreciation expense reduction of $2.172 million.

100. On cross-examination, Jeter admitted that MDU's plant in 1995 was smaller than it is now, so Majoros' depreciation adjustment would have been smaller if applied in 1995. Therefore, Jeter's calculation of the impact of over-depreciation is likely incorrect. Nevertheless, we find there is no justification for charging ratepayers depreciation in

excess of that determined under regulatory depreciation practices. Over-depreciation results in the extraction of capital from ratepayers and is improper from a legal, a regulatory, an economic, and an accounting standpoint.

101. We agree with staff's proposal for depreciation expense and its impact on test year rate base.

Operation and Maintenance Expense

Bonuses and 2003 Labor Expenses

102. Staff witness Majoros proposed to eliminate bonuses from the forecast test year and to hold test year labor costs to their 2002 levels. MDU included average bonuses for the years 1999-2001 in the amount of 6.1 percent of labor costs. Applied to the $8,239,000 in labor costs in 2002, the bonus elimination comes to $503,000. The 2003 labor cost increase eliminated by Majoros amounts to $236,000. These direct labor cost adjustments reduce payroll taxes by $40,000 in 2002 and $60,000 in 2003. [7]

103. Majoros testified that given the state of the economy and the fact that MDU is requesting a rate increase, it would be unreasonable to include bonuses in the revenue requirement.

104. Majoros accepted the 2002 labor cost increase, but objected to extrapolating that increase through 2003. Majoros charted the overall pattern of operating and maintenance costs since 1996 and found that these costs remained relatively stable through the year 2000. Since that time they have since taken a sharp upturn, and MDU projects a 5.7 percent increase each year from 2000 through 2003. This rate of increase exceeds predicted inflation of 2.8 percent annually.

105. MDU witness, Richard D. Spratt, MDU's Vice President – Human Relations, testified on rebuttal. Spratt argued that bonuses are an integral part of overall compensation philosophy to remain competitive with other employers. Part of that compensation is intentionally put at risk in the form of bonuses that are paid on the basis of various goals, including the MDU's overall profitability. Spratt presented the results of an industry survey that showed most utilities pay bonuses not only to management employees, but to salaried and hourly employees as well. Spratt stated that the elimination of bonuses would risk rendering MDU uncompetitive relative to other employers.

106. The issue before the Commission is not whether MDU should pay bonuses or increase salaries. The issue that the Commission must decide is whether such bonuses and raises properly should be included as elements of a rate increase.

[7] Calculated from the data presented on Exhibit 19, MJM-9, pages 1 and 2.

107. C. Wayne Fox, President of MDU Utilities Company, stated that from 1994 through 2001 the Consumer Price Index has risen nearly 20 percent, and in spite of that increase MDU has been able to hold the line on gas rates by finding ways of operating the business more efficiently and taking advantage of new technology. MDU even reduced its rates in 1999, and it did this through improved efficiency. Fox testified that MDU has reduced its employees by 30 percent since 1994. In that year there were 248 customers per MDU employee. In 2001, one employee was serving 370 customers. Then suddenly, beginning in 2001, MDU lost its ability to stay ahead of inflation. MDU's rate increase application not only implies but asserts that this loss of efficiency will continue through 2003. MDU witness, Rita Mulkern testified that while all the past employee reductions are reflected in the 2001 base period data, no further reductions are forecast for 2002 and 2003.[8]

108. During her examination of Mulkern, Commissioner Wefald alluded to the possibility that the Commission might want to give MDU an incentive to practice savings and to find ways to achieve new savings.[9]

109. We find that MDU's rate increase application provides no incentives to improve efficiency. The deterioration in productivity improvement during the years 2001 and 2002 is simply extrapolated into 2003. MDU should not be encouraged to perpetuate its own loss of efficiency. While the 2002 increases in labor costs should be allowed because they have already happened, no further deterioration of labor productivity should be built into the revenue requirement imposed on ratepayers. For this reason, the 2003 labor cost increase are disallowed.

110. The same objective of incentivizing MDU to regain its previous levels of productivity improvement applies to bonuses, only here the incentives apply directly to employees. Apparently, a significant portion of MDU's bonuses is granted on the basis of MDU's overall profitability. Spratt testified that two years ago, presumably in 2000, 75 percent of MDU's employees received 7 percent bonus. Last year, 2001, their bonus was 0.6 percent.[10] Presumably, these bonus levels reflected the fact that in 2000, MDU earned 11.96 percent on its North Dakota Gas Operations, but in 2001, it earned only1.6 percent.

111. If profitability drives bonuses, as it appears, then it is altogether inappropriate to include bonuses in a revenue requirement that drives a rate increase. The reason MDU needs the rate increase is that it is not profitable. If it becomes profitable as a result of a rate increase, that profitability will not have come about because the employees have performed particularly well. To the contrary, it will be because the employees have not performed well, and MDU needs rescue from the Commission.

112. We find that the revenue requirement imposed on ratepayers should not include rewards for poor performance. For this reason, bonuses should be disallowed.

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[8] Tr. Oct 8, page 473.
[9] Tr. Oct 8, page 475.
[10] Tr. Oct 8, page 510.

SISP Costs

113. The Supplemental Income Security Plan ("SISP") is a plan that provides supplemental pension benefits to key employees. "Key employees" are officers, directors and senior managers of MDU Resources and MDU Utilities. The plan is expected to cost $259,000 in 2002 and $265,000 in test year 2003.

114. SISP was initiated in 1982, but MDU never sought its inclusion in revenue requirement until Case No. PU-399-01-186. In its April 24, 2002 decision in that case, the Commission accepted Staff's observation that this plan benefits only the top few employees, those that are already quite well paid. The Commission concluded that it is inappropriate for ratepayers to bear the expense of the SISP costs.[11]

115. MDU witness, Richard A. Espland, acknowledged that his testimony was essentially the same as it was in Case No. PU-399-01-186.[12] Espland acknowledged that SISP benefits only MDU's high salaried employees with income ranges from a low of $75,000 to its president at around $250,000 to $300,000.[13] Espland also agreed that none of the Public Utility Commission's in the jurisdictions where MDU provides natural gas utility services have approved a ratepayer funded SISP program.[14] The Commission took administrative notice of the Findings of Fact, Conclusions of Law and Order in Case No. PU-399-01-186.

116. We find that the exclusion of SISP was appropriate in Case No. PU-399-01-186, and the exclusion of SISP is even more appropriate in this case. Case No. PU-399-01-186 was a Staff-initiated proceeding to reduce MDU's electric rates. This case is a MDU-initiated rate increase proceeding. As noted earlier, one of the reasons MDU seeks to increase rates after an eight-year period of price stability is a result of management's failure to maintain its previous rate of productivity improvement. The management personnel who are most responsible for this failure are the very employees who benefit from SISP. This is not the time to reward them at ratepayers' cost. For this reason, the SISP expense should be disallowed again in this case.

Rate Case Expense Amortization

117. MDU proposes to amortize $168,000 in rate case expenses over three years at $56,000 per year. Staff witness Majoros proposes to amortize the same amount over five years at $34,000 per year, for a difference in annual cost recognition of $22,000. Mulkern suggested that if the five-year amortization is adopted, the unamortized balance should be included as a rate base addition.

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[11] Case No. PU-399-01-186, Findings of Fact, Conclusions of Law and Order, April 24, 2002, ¶68.
[12] Tr. Oct 7, page 148
[13] Tr. Oct 7, page 151
[14] Tr. Oct 7, pages 151-152

118. The basis of Majoros' proposal is the historical period between rate cases. Fox stated in his direct testimony that MDU's last rate increase, in Case No. PU-399-94-297, was decided in 1994, and a rate reduction occurred in 1999 in Case No. PU-399-96-325. This represents two rate cases in eight years, or one every four years. MDU has rounded down to three, and Staff has rounded up to five.

119. We find that there is an important reason for adopting a longer, rather than a shorter amortization period for rate case expenses. Once an amortization becomes embedded in the revenue requirement, it remains there until a new revenue requirement has been calculated resulting in the very real possibility that MDU will over-collect its rate case expenses. MDU is protected from under-recovery of rate case expenses in the event it has another rate case in less than five years, because the amortization can be continued in the new rate case so that MDU ultimately recovers its costs, but only its costs. We find that 5 years is the appropriate amortization period for rate case expenses.

General Inflation Adjustment and Other Unadjusted O&M Expenses

120. In 2001, MDU incurred $89,780,000 in O&M expenses, of which $76,842,000 represented the cost of acquiring gas. Of the remaining $12,938,000 O&M cost relating to distribution, MDU developed specific forecasts for $9,249,000 based on projected changes for various categories of costs, e.g. labor, benefits, insurance, advertising. This left a catch-all category of $3,689,000 of "other" O&M costs, which MDU assumed would increase between 2001 and 2003 by 2.8 percent annually, the assumed rate of general inflation.

121. Majoros noted that the Commission had never previously allowed this sort of inflation-based adjustment, and he recommended that it not start now. The elimination of this adjustment reduces test-year expenses by $209,000.

122. Of the $3,689,000 in 2001 costs within the "other" O&M category, $1,709,000 is non-labor Administrative and General costs. The second largest component of the "other" O&M category, accounting for $981,000 in 2001, is Customer Accounts, a portion of which is accounts receivable.[15] We find that accounts receivable should not vary by general inflation, but rather by the overall size of the total amount billed to customers, including the cost of gas. As demonstrated graphically in Mulkern's rebuttal exhibit RAM-2, gas prices spiked in the last months of 2000 and the first months of 2001, but have since moderated, falling to levels equal or below their 1999 values.[16]

123. MDU's proposal to increase "other" O&M costs at the rate of inflation through 2003 is rejected.

[15] Tr. Oct 8, page 469.
[16] Exhibit 25, RAM-2.

Earnings

124. The Commission finds the following summary of fair and reasonable test year revenue and expenses:

Description	(ND Thousands) 2003 Test Year
Sales	$67,962
Transportation	900
Other	287
Total Revenues	$69,149
Cost of Gas	$50,072
Other O & M Expense	$13,109
Total O & M Expense	$63,181
Depreciation	$1,089
Taxes Other Than Income	$1,292
Current Income Tax Expense	($529)
Deferred Income Taxes	$1,612
Total Expenses	$66,645
Net Regulated Income	$2,504
Income Tax Calculation:	
Net Income Before Taxes	$3,587
Less Interest Deduction:	
Rate Base	$20,767
Weighted Cost of Debt	3.081%
Calculated Interest Deduction	$640
Other Tax Adjustments	$4,282
Taxable Income	($1,335)
Combined Tax Rate	39.61%
Income Tax Expense	($529)

125. The Commission finds that for the 2003 test year, MDU has excess revenue of $1.402 million as follows:

Description	(ND Thousands) 2003 Test Year
Average Rate Base	$20,767
ROR Required	7.979%
Return Required	$1,657
Return Earned	$2,504
Return (Excess) Deficiency	($847)
Tax Factor	1.656
Revenue (Excess) Deficiency	($1,402)

Cost Allocation and Rate Design

Class Cost of Services Study

126. A class cost of service study is an analysis of the embedded or incremental costs of providing utility services to the customers or classes of customers that either cause these costs, or to whom these costs can reasonably be allocated. The purpose of a class cost of service study is to provide an indication of what it costs to provide utility service to each customer class. In prior rate applications the Commission has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers.

127. MDU Witness Tammie Aberle sponsored an embedded cost of service study for the year ended December 31, 2001. This study allocated all of MDU's recorded distribution, general and gas-related common plant among seven categories of customers:

- Residential
- Firm General
- Air Force
- Small Interruptible Sales
- Small Interruptible Transport
- Large Interruptible

128. The costs allocated to the respective customer classes were in turn subdivided into three categories:

- Capacity related costs that vary with the amount of gas sendout on the peak days of the year. Examples include the sizing of distribution mains and meters to account for the maximum volume of gas handled on any one day.

- Throughput related costs that vary with the total amount of gas distributed throughout the year. Uncollectible accounts is a good example of this type of cost.
- Customer related costs that vary with the number of customers. Examples include the cost of meters, services and billing.

129. The only controversy relating to this cost of service study concerned the allocation of the cost of mains. Mains constitute 39.1 percent of MDU's gas distribution plant, but their relevance exceeds even this percentage. That is because general and common plant, which account for another 20 percent of total plant, are allocated as overheads to the direct investment, of which mains are the largest component.

130. In its initial cost of service study, Statement M of Exhibit 2, MDU allocated mains 64 percent on the basis of peak two-day throughput during the year and 36 percent on the basis of the number of customers.

131. King objected to the allocation of a portion of mains costs on a customer count basis. The arguable justification for doing so is that the purpose of the mains system is to reach customers, and that when more customers are added, the mains system has to be extended. King argued that this is true only at the very edges of the system, where gas mains are being extended to serve new developments in previously unserved areas. Even then, the added cost of mains for new customers can vary dramatically depending on the location of those customers.

132. King testified that another purpose of mains is to deliver gas. He argued that the value derived and the benefits received from the mains system are more related to the amount of gas delivered than to the number of customers. One customer receiving twice as much gas as another customer enjoys exactly twice the BTU heating content. The two cannot be equated in terms of benefit received, yet that is what a customer allocation of mains does. He illustrated his point by using the example of a section of main that changes the number and makeup of customers over a period of several years, but the amount of gas delivered remains the same. The weighting of that main in the cost of service study would change under a customer allocation, but it would remain the same (although shifted among customer classes) if the allocation were made on the basis of annual throughput.

133. King therefore asked that MDU conduct an alternative study to allocate half the mains cost according to the classes' two-day peak throughput and half on the basis of annual throughput.

134. On rebuttal, Aberle objected to King's revisions, arguing that main additions are not made only on the edges of the system to provide new service to developments, but are also required to enhance system integrity and maintain pressure throughout the system as customer additions are made. She objected that heating content has no impact on the cost of the mains system. She also objected to the use of a peak-day allocator that assigns costs to the interruptible class and a throughput allocator that

assigns costs to the transmission customers. She argued that both of these allocations violate practices previously approved by the Commission. She submitted yet a third cost of service study, one which allocates mains based 50 percent on throughput at the distribution level and 50 percent on peak day use by firm customers.

135. The results of the three cost of service studies show the rate of return from each customer class as follows:

	MDU Statement M	**King CWK-7**	**Aberle TAA-4**
Residential	3.083%	7.731%	6.367%
Firm General	3.998%	2.161%	1.106%
Air Force	50.281%	3.502%	69.369%
Small Interruptible Sales	83.992%	38.040%	40.905%
Small Interruptible Transport	169.437%	48.490%	57.738%
Large Interruptible	78.644%	-0.673%	27.320%
Total North Dakota	6.439%	6.442%	6.442%

136. As noted earlier, the Commission has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers. We appreciate the information provided by each of the studies because it quantifies the impact that a change in allocation factor has on the rates of return from customer classes. The studies also show that, regardless of the allocator used to allocate mains to customer classes, some customer classes are providing a much higher return on MDU's investment to serve than are other customer classes. In all three studies, the small interruptible customers generate a much higher than average rate of return.

Rate Design

137. In its initial application, MDU made a number of rate design proposals, as follows:

- Increase residential and firm general service rates by 4.6 percent, reduce the small interruptible class rates by 4.1 percent, and leave the Air Force and large interruptible rates unchanged;
- Separate the commodity rate into a Distribution Delivery Charge and a Cost of Gas charge, eliminating the Purchased Gas Cost Adjustment;
- Eliminate the declining block rate form from the commodity charges and substitute a flat per-dekatherm ("dk") rate;
- Change the customer, or "Basic Service Charge" from a monthly to a daily charge;
- Increase the Basic Service Charges by very large percentages, for example, the residential charge increases from $6.50 to $11.70, the small firm service charge from $8.50 to $24.00 and the large firm service charge from $17.00 to $51.00.
- Eliminate the residential seasonal rate;

- Increase the penalty for failure of interruptible customers to interrupt from $10 to $50 per dk;
- Increase the return check fee to $20;
- Increase the reconnection fees for seasonal customers to match the avoided Basic Service Charges;
- Increase the reconnection charge for disconnected customers for nonpayment to $30;
- Modify the Firm Gas Extension Policy Rate 120 and 124 to reflect MDU ownership of all prospective service lines.

138. King recommended that the Commission accept a number of these proposals regardless of whether MDU's overall revenue is increased, decreased, or remains unchanged. These consensus proposals are as follows:

- The commodity rate should be separated into two clearly distinct rates, the Distribution Delivery Charge and the Cost of Gas Rate.
- The declining block rates should be eliminated, and the revenue collected through the higher initial block rates should be reallocated to the Basic Service Charge.
- The residential seasonal rates should be eliminated, since there are no customers on these rates.
- Penalties for failure to interrupt should be increased, since MDU apparently believes that the current penalties are not sufficient to ensure that interruptible customers respond to their calls for interruption or curtailment.
- The reconnection charges for seasonal customers should be adjusted to match the higher Basic Service Charges resulting from the elimination of declining commodity blocks.
- MDU's proposed modifications to the line extension policy should be adopted.

139. King supported MDU's proposal to eliminate declining block commodity rates on the grounds that this rate structure implicitly encourages customers to use more gas, and it thereby discourages conservation. To the extent that it collects fixed customer costs in the commodity rate, it misstates the cause of the costs. Declining block rates also allow customers who use minor amounts of gas for non-heating purposes to escape the cost of providing the basic elements of service to them. We find that the declining block rate should be eliminated to eliminated to more closely reflect cost causation in rates to customers.

140. Using MDU's billing unit counts for the year 2001, King calculated the revenue-neutral increase in monthly customer charges that would result if the present declining block rate structure were eliminated from each rate schedule, as follows:

	Present	Proposed
Small Residential	$6.50	$8.43
Large Residential	$13.00	$15.31
Small Firm Service	$8.50	$14.34
Large Firm Service	$17.00	$45.16

141. The Commission finds that, at a minimum, the monthly customers charge level should be at the amounts shown in the previous table to produce revenue-neutral levels for eliminating the present declining block rates.

142. King also recommended that the Commission consider MDU's proposal to convert the customer charges from monthly to daily charges. This proposal simplifies the calculation of the charge when customers are taking gas for only part of a month. We agree that MDU's monthly customer charge should be converted to a daily customer charge as proposed.

143. King recommended that the Commission reject MDU's proposal to increase the reconnection charge for discontinued service to $30. While MDU claimed that this is a cost-based rate, King suggested that there is a legitimate public policy reason for not increasing this rate. The customers to whom this charge applies are almost certainly the lowest income customers. Otherwise, they would not have been disconnected. Since they have to pay their arrearages anyway, they are likely to be suffering some difficulty getting reconnected. To impose on them yet more cost, such as an increase in the reconnection fee, might prevent some of these customers from obtaining vital utility service. MDU did not respond to King's recommendation. We find MDU's proposal to increase the reconnection charge should be denied.

144. MDU proposed that residential and firm general service customers receive a rate increase of 4.6 percent, that the Air Force and large interruptible customers receive no increase, and that the small interruptible class receive a reduction of 4.1 percent. King pointed out that the Commission's past practice has been to recognize differences in class rates of return by approving lower rate increases to classes with the highest rates of return. It has not approved rate reductions to some classes when most customers are suffering rate increases. We find that all classes, regardless of their rates of return, should receive some rate increase if overall revenues are increased and a rate reduction if overall revenues are reduced.

145. King had similar misgivings about MDU's proposal to increase customer charges dramatically, even for the classes for which it was proposing rate reductions or no rate increases. MDU witness Russell Feingold argued that shifting revenue recovery from the commodity to the customer component allows MDU to recover much more of its fixed costs on a non-weather sensitive basis. He asserted that this shift also protects customers from the volatility in their gas bills caused by variations in weather.

146. King was concerned with the issue of rate continuity. The sort of changes proposed by MDU would result in dramatically different bills for different types of customers. Very low-use customers might find the increases in their average monthly bills extortionate. Customers accustomed to low gas bills in the summer, that possibly offset high electric bills, could be surprised by the sudden jump in their gas invoices.

147. King was concerned that customers may also resent high monthly customer charges. When most of the cost of gas is based on the level of gas consumption, customers can avoid high gas bills by conserving gas. But no amount of conservation permits a customer to avoid a monthly customer charge. As long as this charge is not a major portion of the bill, it is likely to be acceptable to most customers. But if it looms as a major element in the cost of gas, customers will come to regard it as a tax from which there is no escape.

148. King recommended that customer charges should not be increased by more than twice the overall increase. This ceiling on customer charge increases would be in addition to the increases in customer charges that result from the flattening of the declining block rates. If rates are reduced, the reductions should be flowed entirely into the commodity component of each rate schedule. Customer charges should not be increased when rates are reduced, except to eliminate the declining block feature of the rate schedules.

149. The Commission agrees with King's recommendation concerning customer charges.

Distribution Delivery Stabilization Mechanism

150. If the Commission disapproves of MDU's dramatic increases in customer charges, MDU proposes that, as an alternative, the Commission adopt a Distribution Delivery Stabilization Mechanism ("DDSM"). As described by Feingold, the DDSM would modify the effects of weather variations by adjusting bills for the difference between the actual heating degree days and heating degree days under normal weather. Following a cold winter, the excess in each class's revenue from the greater number of heating degree days would be divided by the projected annual sales volumes in that class and credited to all customers over the following year on a per-dk basis. The revenue shortfall from a warmer than normal winter would similarly be collected through a surcharge to all customers during the subsequent year.

151. Staff has gone part of the way toward MDU's objective of increasing customer charges. Staff has recommended that the commodity rates be flattened, and the revenue previously collected in the high initial blocks be recovered through increased customer charges. Staff has also recommended that any overall revenue increase be tilted toward the increased customer charges, and any overall rate decrease be flowed through entirely to the commodity charges. At the hearing, Aberle, MDU's rate design witness, could not say whether these concessions to MDU's target of increasing

customer charges relative to commodity charges were sufficient to persuade MDU to withdraw the DDSM proposal.

152. King testified that the value of a weather normalization adjustment should be to ameliorate the volatility in customer bills caused by variations in weather, and particularly the effect of unusually cold winters. In such winters, ratepayers typically experience a "double whammy." First, they consume more gas than usual, which increases their bills even if the price of gas remains the same. Then, because cold winters are usually a widespread phenomenon, the demand for gas is higher across the continent, which means that the price of gas is higher. The result is a further inflation in their bills. Just this sort of inflation occurred across the country during the winter of 2000-2001.

153. King suggested that MDU's proposal could result in a "triple whammy." If North Dakota experiences an unusually warm winter, and it is followed by an unusually cold winter, ratepayers during the cold winter, already hard-hit, would find themselves paying a surcharge to make up for the shortfall in revenue collections in the previous year. The effect of MDU's program could be to increase, not decrease the volatility in customers' bills from year to year.

154. The Commission finds that MDU's proposal should be denied because of its delayed effect. For a weather normalization adjustment to be beneficial to ratepayers and not just the utility, it must affect their bills when the unusual weather is occurring, not after it has occurred.

From the foregoing Findings of Fact, the Commission makes its:

Conclusions of Law

1. The Commission has jurisdiction over the parties in and the subject matter of this proceeding.

2. MDU is entitled to rates and charges necessary to provide it an opportunity to earn a reasonable rate of return on its North Dakota electric property, used and useful, for the service and convenience of the public in North Dakota.

3. MDU's existing natural gas rates yield excess revenues of $1.402 million per year.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

Order

The Commission orders:

1. MDU shall implement a rate reduction sufficient to produce a total annual rate revenue decrease of $1.402 million.

2. MDU shall file revised tariff sheets reflecting the rate reduction to be effective for natural gas service rendered on and after January 1, 2003.

PUBLIC SERVICE COMMISSION

Anthony T. Clark **Commissioner**	**Susan E. Wefald** **President**	**Leo M. Reinbold** **Commissioner**

APPROVED

DATE: 11-6-02

MOTION

November 6, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission bill Montana-Dakota Utilities Co. for costs incurred to date in Case No. PU-399-02-183, Montana-Dakota Utilities Co., Natural Gas Rate Increase, Application.

88 **PU-399-02-183** Pages 3

Utility Valuation Motion/Letter/Billing Statement
by Public Service Commission

11/06/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

November 6, 2002

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

RE: Case No. PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the November 6, 2002 Public Service Commission meeting for the expenses incurred to date in Case No. PU-399-02-183.

Under N.D.C.C. 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Administrative Staff Officer
701-328-2401

Enc.

Billing Statement

November 6, 2002

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

Expenses Incurred to Date:

Consulting Services	$12,420.00

Amount Due:

Montana-Dakota Utilities Co.	$12,420.00

Send Payment and a Copy of this Statement To:

Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

PY-399-02-183

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Douglas W Schulz
MDU
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 3-14-03

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 2510 0001 2975 2631

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1035

PY-399-02-183

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

William Pearce
PO Box 400
Bismarck ND 58502-0400

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) Roger Krause C. Date of Delivery 3-14-03

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 2510 0001 2975 2648

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1035

PY-399-02-183

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
MDU
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 3.14.03

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

PU-399-02-183

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

William Pearce
PO Box 400
Bismarck ND 58502-0400

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) Roger Francis | C. Date of Delivery 12-20

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 1940 0005 3425 2375

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

PU-399-02-183

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] | C. Date of Delivery 12 2002

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 1940 0005 3425 2382

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

PU-399-02-183

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Douglas W Schultz
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] | C. Date of Delivery 12 2002

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number 7001 1940 0005 3425 2374

PU-399-02-183

ENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Douglas W Schulz
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 12/11/02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 1940 0005 3425 2306

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

PU-399-02-183

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
MDU
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 12-11-02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 1940 0005 3425 2276

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

PU-399-02-183

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Ord Ball — B. Date of Delivery 11-12-02

C. Signature
X Ord Ball ☐ Agent ☒ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* 7001 2510 0001 2975 3102

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

PU-399-02-183

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
William P Pearce
PO Box 400
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Roger Krance ☒ Agent ☐ Addressee

B. Received by *(Printed Name)* Roger Krance — C. Date of Delivery 12-11-02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Transfer from service label)* 7001 1940 0005 3425 2313

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

RECEIVED
AUG 26 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

PROTECTIVE AGREEMENT

I understand that an application has been filed with the Commission or that the Commission has granted trade secret protection to certain information filed by Montana-Dakota Utilities Co. in the captioned matter. I agree to keep the designated information confidential and to be bound by the terms of this agreement, North Dakota Administrative Code Chapter 69-02-09, and any Commission order regarding trade secret protection issued in this case.

I intend to review the following trade secret information:

All trade secret information relating to this proceeding including trade secret information contained in responses to data requests.

Dated: August 23, 2002

(Signature of person reviewing information)

WARNING: A violation of this agreement may subject the violator to civil and criminal liability.

Legal/Word/SLS/Protective Agreement

162 PU-399-02-183 Pages. 3
Protective Agreements for Trade Secret
by Public Service Commission
02/16/2006 CC: Comm Legal PUD (4) Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

(case title and number)
XTO Southern Pine Lateral
PU-399-02-183

PROTECTIVE AGREEMENT

I understand that the Commission has granted Trade Secret protection to certain information filed by XTO in the captioned matter. I agree to keep the designated information confidential and to be bound by the terms of this agreement, North Dakota Administrative Code chapter 69-02-09, and any Commission order regarding trade secret protection issued in this case.

I intend to review the following trade secret information:
Response to Data Request - Duffy dtd 8-23-02

Dated: 8-23-02

(signature of person reviewing information)

WARNING: A violation of this agreement may subject the violator to civil and criminal liability.

cgc\protagmt

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

(case title and number)
MDU Natural Gas Rate Increase
PU-399-02-183

PROTECTIVE AGREEMENT

I understand that the Commission has granted Trade Secret protection to certain information filed by MDU in the captioned matter. I agree to keep the designated information confidential and to be bound by the terms of this agreement, North Dakota Administrative Code chapter 69-02-09, and any Commission order regarding trade secret protection issued in this case.

I intend to review the following trade secret information:

Response to Data Request - dated 8-9-02

Dated: 8-13-02

(signature of person reviewing information)

WARNING: A violation of this agreement may subject the violator to civil and criminal liability.

cgc\protagmt

161 **PU-399-02-183** Pages: 0

Trade Secret Material shredded

by Public Service Commission

02/16/2006 CC: Comm Legal PUD (4) Mike .

APPROVED

DATE: 8-28-03

KMF

MOTION

August 28, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission approve tariff changes effective for bills rendered on or after September 1, 2003 filed in compliance with the Commission's July 31, 2003 Order Approving Settlement Agreement in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application, Case No. PU-399-02-183.

JRL/sdh

160 **PU-399-02-183** Pages: 1

Motion to approve compliance tariffs

by Public Service Commission

08/28/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **15th day of August, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with fully prepaid, securely sealed and each containing a photocopy of:

Staff Response to Compliance Filing

The envelope were addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Dan Kuntz
P O Box 1695
Bismarck ND 58502-0400

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sandra L Scott

Subscribed and sworn to before me
this **15th day of August, 2003**.

Susan K. Richter
Notary Public

SEAL

SUSAN K. RICHTER
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 15, 2004

159 PU-399-02-183 Pages: 1

Affidavit of Service

by Public Service Commission

08/15/2003 CC: Comm Legal Illona, Pat, Jerry Mike

RECEIVED
AUG 15 2003
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

STAFF RESPONSE TO COMPLIANCE FILING

August 15, 2003

On August 8, 2003, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) filed tariff changes to comply with the Order of the Commission dated July 31, 2003. The Commission's Order adopted a Settlement Agreement by which MDU is to implement a rate decrease sufficient to provide a total annual revenue decrease of $362,085 effective for service rendered on or after September 1, 2003. The Settlement Agreement indicated that the rate reduction is to be applied to the rate classes in the same manner as the increase that was effective with rate change granted December 12, 2002. Settlement Agreement indicated that the rate change is to be implemented as a reduction to the distribution delivery charge.

MDU's compliance tariffs provide a total annual revenue decrease of $361,426. The rate reduction is split between the Residential and Firm General Service classes in approximately the same proportion as the rate change granted December 12, 2002, that is 61.3% of the decrease is allocated to the Residential customers and 38.7% is allocated to the Firm General Service customers. This results in a 0.55% reduction to each class of customer.

The rate reduction was applied to the Distribution Delivery Charge per dekatherm. The Residential distribution charge was reduced from $0.669 to $0.641 which results in a reduction in annual revenue to MDU of $221,196. The Firm General Service distribution charge was reduced from $0.498 to $0.473 which results in a reduction in annual revenue to MDU of $140,231.

Staff believes that MDU's compliance filing satisfies the Commission's Order.

William W. Binek
Chief Counsel

158 PU-399-02-183 Pages: 1

Staff Response to Compliance Filing

by Public Service Commission

08/15/2003 CC: Comm Legal Illona, Pat, Jerry Mike

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

August 7, 2003

RECEIVED
AUG 8 2003
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

Executive Secretary
North Dakota Public Service Commission
State Capitol
Bismarck, ND 58505-0480

Re: Case No. PU-399-02-183
Compliance Tariffs –
Depreciation Settlement

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits an original and seven copies of revised natural gas tariff sheets and supporting workpaper in compliance with the Settlement Agreement approved by the North Dakota Public Service Commission (Commission) on July 31, 2003.

The rates set forth on the revised tariff sheets will result in a reduction in annual revenues of $362,085. The rate reduction was applied to the distribution delivery charge component in a manner consistent with that of the increase authorized on December 10, 2002. The overall affect is a decrease in authorized revenues of .55% for the residential and firm general customer classes.

Montana-Dakota hereby requests that the change to the distribution delivery charges reflected on the tariffs attached hereto be approved in conjunction with the implementation of the September 2003 Purchased Gas Cost Adjustment (PGA) on a bills rendered basis September 1, 2003. The Rate Summary Sheet reflecting the revised distribution delivery charge rates and the September PGA items will be filed in conjunction with the Company's PGA filing.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto.

Sincerely,

Donald R. Ball

Donald R. Ball
Assistant Vice President –
Regulatory Affairs

157 PU-399-02-183 Pages: 13
Revised natural gas tariff sheets
by Montana-Dakota Utilities Co., a Division of MDU Re
08/08/2003 CC: Comm Legal Illona, Pat, Jerry Mike

Montana-Dakota Utilities Co.
Gas Utility - North Dakota
Allocation of Revenues as Authorized for Case No. PU-399-02-183 1/
Reflecting Order Approving Settlement Agreement on Depreciation Study

	Authorized Increase in Revenue	Allocation of Original Increase	Decrease Due to Depreciation Settlement	Authorized Dk	Authorized Revenue Reflecting Decr	Distribution Delivery Charge Per Dk			
						Current 2/	Decrease due Depr Settlement	9/01/03 Rates	% Decrease
Residential	$1,208,221	61.2688%	($221,845)	7,899,840	$40,188,874	$0.669	($0.028)	$0.641	-0.55
Firm General Service	763,779	38.7312%	(140,240)	5,609,220	25,401,736	0.498	(0.025)	0.473	-0.55%
Air Force									
Firm						0.138		0.138	0.00%
Interruptible						0.120		0.120	0.00%
	0	0.0000%	0	1,051,240	2,580,856				
Small Interruptible									
Sales						0.871		0.871	0.00%
Transportation						0.427		0.427	0.00%
	0	0.0000%	0	1,520,140	1,961,155				
Large Interruptible									
Sales						0.719		0.719	0.00
Transportation						0.298		0.298	0.00
	0	0.0000%	0	2,246,820	342,596				
Total North Dakota	$1,972,000	100.0000%	($362,085)	18,327,260	$70,475,217				

Authorized Increase	$1,972,000
Depr Settlement Decr	362,085
Proposed Increase	$1,609,915

1/ Rates effective with service rendered on and after December 12, 2002, implemented on December 18, 2002 per Compliance Filing dated December 13, 2002.
2/ Interruptible and transportation rates reflect the maximum distribution delivery charge.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
2nd Revised Sheet No. 4
Canceling 1st Revised Sheet No. 4

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.29 per day
Distribution Delivery Charge:	$.641 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

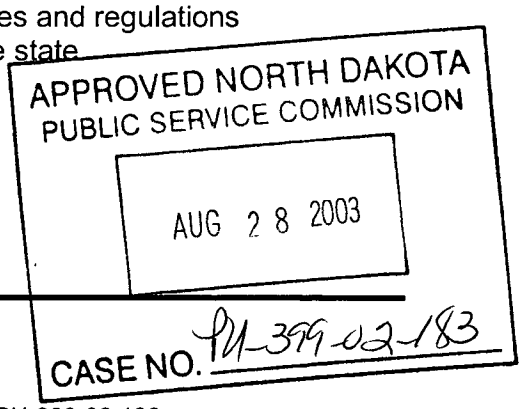
Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.



Date Filed: August 7, 2003

Effective Date:

Issued By: Donald R. Ball
Assistant Vice President -
Regulatory Affairs

Case No.: PU-399-02-183

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
2nd Revised Sheet No. 13
Canceling 1st Revised Sheet No. 13

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.473 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 129 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
AUG 28 2003
CASE NO. PU-399-02-183

Date Filed:	August 7, 2003	**Effective Date:**	
Issued By:	Donald R. Ball Assistant Vice President - Regulatory Affairs	**Case No.:**	PU-399-02-183

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
2nd Revised Sheet No. 15
Canceling 1st Revised Sheet No. 15

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.473 per dk
Cost of Gas:	
Winter- Bills rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Bills rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
AUG 28 2003
CASE NO. PU-399-02-183

Date Filed: August 7, 2003 **Effective Date:**

Issued By: Donald R. Ball
Assistant Vice President - Regulatory Affairs

Case No.: PU-399-02-183

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
2nd Revised Sheet No. 32
Canceling 1st Revised Sheet No. 32

RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.29 per day
Distribution Delivery Charge:	$.641 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

RECEIVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
AUG 28 2003
PU-399-02-183
CASE NO. PU-399-02-183

Date Filed:	August 7, 2003	**Effective Date:**	
Issued By:	Donald R. Ball Assistant Vice President - Regulatory Affairs	**Case No.:**	PU-399-02-183

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
2nd Revised Sheet No. 34
Canceling 1st Revised Sheet No. 34

FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.473 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

The cost of propane as defined in the Purchased Propane Cost Adjustment Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
AUG 28 2003
CASE NO. PU-399-02-183

Date Filed: August 7, 2003
Effective Date:

Issued By: Donald R. Ball
Assistant Vice President - Regulatory Affairs

Case No.: PU-399-02-183

Tariffs Reflecting Changes

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 4
Canceling Original Sheet No. 4

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.29 per day
Distribution Delivery Charge:	$.~~669~~ 641 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Assistant Vice President -
Regulatory Affairs

Case No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 13
Canceling Original Sheet No. 13

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.~~498~~ 473 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Gas:

The cost of gas includes all applicable cost of gas items as defined in the Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Assistant Vice President - Regulatory Affairs

Case No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 15
Canceling Original Sheet No. 15

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.~~498~~ 473 per dk
Cost of Gas:	
Winter- Bills rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
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Minimum Bill:

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Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
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State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 32
Canceling Original Sheet No. 32

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Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

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Distribution Delivery Charge:	$.~~669~~ 641 per dk
Cost of Propane:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Purchased Propane:

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General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 34
Canceling Original Sheet No. 34

FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

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For customers with meters rated under 500 cubic feet per hour	$0.50 per day
For customers with meters rated over 500 cubic feet per hour	$1.70 per day
Distribution Delivery Charge:	$.~~498~~ 473 per dk
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Minimum Bill:

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **4th day of August, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Order Approving Settlement Agreement

The envelope was addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2410 0003 4912 3464

Dan Kuntz
P O Box 1695
Bismarck ND 58502-0400
Cert. No. 7001 2410 0003 4912 3471

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2410 0003 4912 3488

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **4th day of August, 2003**.

Sandra L Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **4th day of August, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Order Approving Settlement Agreement

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **4th day of August, 2003**.

Sandra L Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

ccano@mh.com
Craig Cano
Gas Utility Report
1200 G St NW Ste 1100
Washington DC 20005

inland@btigate.com
Inland Oil & Gas Corp
PO Box 1313
Bismarck ND 58502-1313

jason_gustafson@bobcat.com
Jason Gustafson
Melroe Company
P O Box 128
Gwinner ND 58040-0128

craig_scott@bobcat.com
Craig Scott
Melroe Company
P O Box 128
Gwinner ND 58040-0128

balld@mdu.mdures.com
Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

collinsk@mdu.mdures.com
Karen Collins
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

mdickerson@state.nd.us
Marcy Dickerson
State Tax Department
State Capitol
Bismarck ND 58505

dave.sederquist@xcelenergy.com
Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58108-2747

F James Moriarty
2333 Plum Grove Dr
O'Fallon MO 63366

Steven Tomac
2498 59th St
St Anthony ND 58566-9640

Will Kaul
Cooperative Power Association
P O Box 800
Elk River MN 55330-0800

Patricia Estes
Daily News
PO Box 760
Wahpeton ND 58074-0760

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Frank Morehouse
Great Plains Natural Gas Co
PO Box 176
Fergus Falls MN 56548-0176

Jay Casler
INDEPTH DATA INC
44 S Bdwy 18th Fl
White Plains NY 10601-4425

Karyn Grass
IPAMS
6620 Denver Club Bldg 518 17th St
Denver CO 80202-4167

Rick Jensen
KHND AM Radio
PO Box 6
Harvey ND 58341-0006

Kelley Richardson
King Publishing Co
PO Box 52210
Knoxville TN 37950-2210

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

Minnesota PUC
121 E 7th Pl Ste 350
St Paul MN 55101-2147

Bruce Imsdahl
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Ron Tipton
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

Robert Burns
National Regulatory Research Inst
406 Bevis Hall 1080 Carmack
Columbus OH 43210

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Scott Speaker
Natural Gas Week
1401 New York Ave NW Ste 500
Washington DC 20005-2150

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Jamie Seitz
Xcel Energy
825 Rice St
St Paul MN 55117

Paul Lehman
Xcel Energy
512 Nicollet Mall
Minneapolis MN 55402

Helbling, Sharon D.

From: Helbling, Sharon D.
Sent: Monday, August 04, 2003 8:55 AM
To: 'balld@mdu.mdures.com'; 'ccano@mh.com'; 'collinsk@mdu.mdures.com'; 'craig_scott@bobcat.com'; 'dave.sederquist@xcelenergy.com'; 'inland@btigate.com'; 'jason_gustafson@bobcat.com'; 'mdickerson@state.nd.us'
Subject: Order Approving Settlement Agreement Case NO. PU-399-02-183 MDu Natural Gas Rate Increase

1.doc

MOTION

APPROVED
DATE: 7-31-03
KMF

July 31, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission adopt the Order Approving Settlement Agreement in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application, Case No. PU-399-02-183.

JRL/sdh

155 PU-399-02-183 Pages: 1
Motion
by Public Service Commission
07/31/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

ORDER APPROVING SETTLEMENT AGREEMENT

July 31, 2003

Appearances

Commissioners: Tony Clark, Leo M. Reinbold, Susan E. Wefald

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy staff.

Daniel S. Kuntz, Attorney at Law, 316 North Fifth Street, PO Box 1695, Bismarck, ND 58502-1695 appearing for Montana-Dakota Utilities Co.

Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

On December 18, 2002, the Public Service Commission issued its Corrected Findings of Fact, Conclusions of Law and Order resolving all issues in this proceeding except depreciation. The Commission accepted a proposal by the parties to continue the issue of depreciation pending completion of a depreciation study. The Commission required that Montana-Dakota Utilities Co. (MDU) file its depreciation study by January 31, 2003, which would then be subject to Commission Staff (Staff) review including discovery, testimony and hearing. MDU's depreciation study was to include natural gas and common plant facilities. Any resulting change in depreciation expense ordered by the Commission at the conclusion of the review would be reflected in rates on a prospective basis.

On January 31, 2003, MDU filed its depreciation study.

On March 12, 2003, the Commission issued a Notice of Hearing and Procedural Schedule, scheduling a public hearing to begin on April 22, 2003, subsequently rescheduled to July 1, 2003, at the Commission Hearing Room at the Commission's

154 PU-399-02-183 Pages: 21
Order Approving Settlement Areement
by Public Service Commission
07/31/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

offices in Bismarck. The notice identified the following issues to be considered in this proceeding:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is the appropriate treatment of plant retirement costs?

3. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

On July 1, 2003, a hearing was convened as scheduled. A motion for continuance to an informal hearing on July 9, 2003 was immediately granted to allow time for the parties to finalize a settlement agreement.

On July 8, 2003, the parties filed a Settlement Agreement intended to resolve all issues in this proceeding.

On July 9, 2003 the Commission discussed the Settlement Agreement with the parties at an informal hearing.

Settlement Agreement

The Settlement Agreement is a negotiated settlement, subject to Commission approval, and does not establish any principle or precedent, except as expressly provided therein.

Attachment 1 to the Settlement Agreement is a schedule by functional plant categories and accounts of existing and agreed upon depreciation rates and the annual system-wide depreciation expenses based on depreciable plant in service on December 31, 2001. The Settlement Agreement provides an effective date of September 1, 2003, for the proposed new depreciation schedules and resulting retail rates.

The parties agree that the rate impact of the depreciation schedules agreed to in attachment 1 decreases MDU's annual revenue requirement by $362,085. The Settlement Agreement provides that MDU file revised tariff sheets not less than ten days prior to the effective date and proportions the revenue decrease among the customer rate classes in the same manner as prescribed for the increase authorized by the Commission in its order of December 18, 2003.

Having reviewed the testimony and other information provided by the parties, the Commission finds the Settlement Agreement is a fair and reasonable resolution of the remaining issues in this Case. The resulting rates and charges for retail natural gas service will provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota. The Commission

concludes that the Settlement Agreement is in the public interest and should be approved.

Order

1. The attached Settlement Agreement is approved.

2. The depreciation rates for natural gas and common utility plant agreed to in Attachment 1 to the attached Settlement Agreement are approved.

3. MDU shall file revised tariff sheets as agreed to in the attached Settlement Agreement effective for service rendered on or after September 1, 2003.

PUBLIC SERVICE COMMISSION

Susan E. Wefald	**Tony Clark**	**Leo M. Reinbold**
Commissioner	**President**	**Commissioner**

ZUGER KIRMIS & SMITH

COUNSELORS AND ATTORNEYS AT LAW

Lyle W. Kirmis
Lance D. Schreiner, P.C.
James S. Hill, P.C.
Patrick J. Ward
Rebecca S. Thiem, P.C.
Daniel S. Kuntz, P.C.
Jerry W. Evenson, P.C.
Lawrence A. Dopson
Lawrence E. King, P.C.
Tracy Vigness Kolb, P.C.
Shawnda R. Reid
Constance N. Hofland
Paul R. Sanderson

316 North Fifth Street
Provident Building
P.O. Box 1695
Bismarck, ND 58502-1695
(701) 223-2711
fax (701) 223-7387
www.zkslaw.com
email: zkslaw@zkslaw.com

Of Counsel
John A. Zuger

Thomas O. Smith
1944-2001

RECEIVED
JUL - 8 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

July 8, 2003

Mr. Jon Mielke
Executive Secretary
ND Public Service Commission
600 East Boulevard Avenue -- 12th Floor
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co. Depreciation Study – Case No. PU-399-02-183

Dear Mr. Mielke:

Enclosed for filing are the original and seven copies of the a Settlement Agreement entered into by Montana-Dakota Utilities Co. and the Staff of the North Dakota Public Service Commission. Acceptance of this Settlement Agreement by the Public Service Commission would resolve all outstanding continued issues in this case. The parties to the Settlement Agreement request that the Agreement be brought to the attention of the Public Service Commission for consideration at the informal hearing on this matter scheduled for July 9, 2003.

Please contact me or Bill Binek if you have any questions regarding this Agreement.

Sincerely,

Daniel S. Kuntz

Enclosures

c: Don Ball
Bill Binek

151 PU-399-02-183 Pages: 1
Cover letter re Settlement Agreement
by Montana-Dakota Utilities Co , a Division of MDU Re
07/08/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

JUL - 8
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.	)	Case No. PU-399-02-183
Depreciation Study	)	

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into by and between Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company") and the Staff of the North Dakota Public Service Commission ("Staff"). This Settlement Agreement resolves all outstanding continued issues in this case in a manner consistent with the public interest and will result in just and reasonable depreciation rates and expense accruals for the Company's natural gas distribution operations in North Dakota.

PROCEDURAL HISTORY

1. On April 12, 2002, Montana-Dakota filed an application for an increase in its North Dakota retail natural gas rates based on a 2003 projected test year. The North Dakota Public Service Commission ("Commission") suspended Montana-Dakota's rate filing and set the matter for investigation and hearing. The disputed issues between Montana-Dakota and the Staff included the proper depreciation rates and depreciation expenses for the test year. The Staff's witness recommended that the test year depreciation expenses proposed by the Company be reduced. The Company's witness maintained that no depreciation rate adjustments should be entertained until a depreciation study being conducted by the Company was completed and reviewed.

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Settlement Agreement
by Montana-Dakota Utilities Co., a Division of MDU R
07/08/2003 CC: Comm Legal Illona, Pat, Jerry Mike

Montana-Dakota asked the Commission to defer any consideration of the depreciation issue until Montana-Dakota's new depreciation study was complete, Montana-Dakota agreed to submit the new depreciation study for review by January 31, 2003 as a continued issue in this proceeding subject to the standard and customary contested case process with all parties having rights of discovery, testimony, rebuttal testimony, hearing and briefing.

2. In its Order issued December 18, 2002, the Commission approved continuation of the depreciation issue. Montana-Dakota was directed to file its depreciation study as soon as possible but no later than January 31, 2003. Any resulting changes in depreciation expense ordered by the Commission at the conclusion of the review of the depreciation study would be reflected in rates on a prospective basis.

3. On January 31, 2003, Montana-Dakota filed depreciation studies prepared by AUS Consultants related to Montana-Dakota's common and gas division utility plant.

4. On March 12, 2003, the Commission issued a Notice of Hearing and Procedural Schedule setting the following issues for consideration on Montana-Dakota's depreciation studies:

1. What is the value of Montana-Dakota's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is the appropriate treatment of plant retirement costs?
3. What rates and charges are necessary to provide a just and reasonable rate of return on Montana-Dakota's property, used and useful, for the service and convenience of the public in North Dakota?

A hearing on the above issues was scheduled for April 22, 2003. On April 23, 2003, the Commission rescheduled the hearing to July 1, 2003.

5. The Company's depreciation studies indicated the Company's existing depreciation rates, applied to total system-wide depreciable gas division utility plant in service as of December 31, 2001 resulted in an annual depreciation expense of $7,694,754. In comparison, application of the study's proposed depreciation rates to the same depreciable plant in service as of December 31, 2001 would result in an annual depreciation expense of $8,010,389; an increase of $315,635 from existing rates. The composite annual depreciation rate under the existing rates is 4.52% while the Company's study recommended a proposed composite depreciation rate of 4.70%.

6. For common utility plant, the studies indicated the application of existing rates to total system-wide depreciable common plant in service as of December 31, 2001 resulted in an annual depreciation expense of $2,167,043. Application of the proposed depreciation rates to the total system-wide depreciable common plant in service as of December 31, 2001 would result in an annual depreciation expense of $2,666,460; an increase of $499,417 from the existing rates. The composite annual depreciation rate for common plant under the existing rates is 5.84%, while the studies proposed composite depreciation rate for common plant would be 7.18%.

7. On April 7, 2003, the consultant for the Staff, Charles W. King, filed direct testimony reviewing and critiquing the depreciation study prepared by AUS Consultants. Mr. King also recommended alternative depreciation rates for the gas division and common utility plant of Montana-Dakota. The following is a comparison of the Company's existing

depreciation rates as well as those recommended by the Company and the Staff:

Plant Category	Existing Composite Rate	Existing Annual Expense	Company Proposal Composite Rate	Company Proposal Annual Expense	Staff Proposal Composite Rate	Staff Proposal Annual Accrual
Gas Distribution	4.46%	$6,758,717	4.01%	$6,082,611	2.33%	$3,535,250
Gas General	4.98%	$ 936,037	10.25%	$1,927,777	5.27%	$ 990,871
Common	5.84%	$2,167,042	7.18%	$2,666,459	5.27%	$1,955,583

8. On April 28, 2003, the Company filed rebuttal testimony of Earl M. Robinson responding to the testimony and recommendations of Mr. King.

9. Following the analysis of the depreciation studies and the testimony of the parties respective witnesses, settlement discussions were held between the Staff and Company representatives in accordance with the Commission's proposed settlement guidelines (July 1994). As a result of those discussions, the parties have reached this Settlement Agreement. The parties agree the Settlement Agreement resolves all issues in the proceeding in a manner consistent with applicable law and the settlement guidelines.

10. The Settlement Agreement is supported by the administrative record. Accordingly, the parties jointly recommend the Commission issue an Order: (a) approving this Settlement Agreement in its entirety, without conditions or modifications; (b) approving the depreciation rates for the Company's natural gas distribution and common utility plant; and (c) directing the Company to file revised rate schedules reflecting the impact of the proposed depreciation rates on the Company's existing natural gas retail rates in North Dakota and implementing changes in its natural gas retail rates consistent with this

Settlement Agreement.

TERMS OF SETTLEMENT AGREEMENT

Attachment 1 is a schedule by functional plant categories and accounts of the existing and agreed depreciation rates and the annual system-wide depreciation expenses based upon depreciable plant in service at December 31, 2001. A comparison of the existing rates and expenses, the Company proposal, the Staff proposal, and the recommended depreciation rates and annual expense accruals based on December 31, 2001 system-wide plant in service is shown in Attachment 2.

Staff and Montana-Dakota agree and recommend that the Commission approve the recommended depreciation rates on Attachment 1.

The recommended depreciation rates were arrived through negotiations based upon the studies and testimony provided by the expert consultants for the Staff and the Company. Although the Staff and the Company agree and recommend the depreciation rates set forth on Attachment 1, the parties do not adopt or recommend as part of this Settlement Agreement the amount or a methodology for determining net salvage and average service lives for the various plant accounts. Nothing in this Settlement Agreement shall limit the authority of the Commission to establish, or the Staff and the Company to advocate, in future proceedings, the appropriate methodology or the appropriate amounts of net salvage and average service lives for the various plant accounts.

EFFECTIVE DATE OF REVISED RATES

Subject to approval by the Commission of this Settlement Agreement, the revised depreciation rates and the resulting retail rate change will become effective September 1,

2003.

RETAIL RATE ADJUSTMENT

Upon approval of the Settlement Agreement by the Commission, the Company shall file revised tariff sheets reflecting changes to its North Dakota retail natural gas rates based upon the depreciation rate changes which is a reduction in annual revenues of $362,085. Attachment 3 shows the calculation of the North Dakota natural gas retail rate reduction to reflect the recommended depreciated rates and expense accruals. The rate reduction shall be applied to the rate classes in the same manner as the increase that was effective with service rendered December 12, 2002. The applicable change will be implemented as a reduction to the distribution delivery charge component of the rate. The revised tariff sheets shall be filed not less than ten (10) days prior to the effective date.

OTHER TERMS AND CONDITIONS

A. Basis of Settlement.

It is agreed this Settlement Agreement contains negotiated depreciation rates and accrual amounts subject to approval by the Commission. The Settlement Agreement does not establish any principle or precedent regarding the methodology for establishing depreciation rates.

B. Effect of the Settlement Negotiations.

It is understood and agreed that all offers of settlement and discussions related to this Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Public Service Commission does not approve this Settlement Agreement, it shall not constitute

part of the record in this proceeding and no part thereof may used by any party for any purpose in this proceeding or otherwise.

C. Applicability and Scope.

This Settlement Agreement shall be binding on the parties hereto, and their successors, assigns, agents and representatives. Consistent with the Commission's 1994 proposed settlement guidelines, this Settlement Agreement does not set policy or overturn precedent.

D. Effective Date.

This Settlement Agreement shall be effective on the date of final Commission Order approving the Settlement Agreement with the revised depreciation rates and corresponding revised retail rates effective on the dates specified herein. If the Commission Order modifies or conditions approval, this Settlement Agreement shall be deemed terminated if either party files a letter with the Commission within 3 (three) business days of notice of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

Dated this 8th day of July, 2003.

Montana-Dakota Utilities Co.

By: Ronald R. Hall
Its: Assistant Vice President - Regulatory Affairs

Dated this 8th day of July, 2003.

North Dakota Public Service Commission

By: [signature]
Chief Counsel

Montana-Dakota Utilities Company
Gas Division
SETTLEMENT POSITION
Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	Distribution Plant						
374.20	Rights of Way	89,641	2.56%	2,313	0.75%	672	-1,640
375.00	Distr. Meas & Reg Station Structures	521,210	2.40%	12,509	2.57%	13,395	886
376.00	Mains	78,334,154	4.05%	3,172,533	1.92%	1,504,016	-1,668,517
378.00	Meas & Reg Station Equip-General	1,367,334	2.30%	31,449	2.96%	40,473	9,024
379.00	Meas & Reg Station Equip-City Gate	1,009,137	2.74%	27,650	3.54%	35,723	8,073
380.00	Services	32,476,717	7.60%	2,468,231	5.66%	1,838,182	-630,048
381.00	Meters	30,462,008	2.58%	785,920	3.19%	971,738	185,818
383.00	Service Regulators	4,296,862	2.37%	101,836	2.59%	111,289	9,453
385.00	Industrial Meas. & Reg. Station Equipment	578,200	1.91%	11,044	3.04%	17,577	6,534
						4,533,066	
	MISCELLANEOUS EQUIPMENT						
386.10	Miscellaneous Property on Customers Premise	1,680	9.35%	157	5.19%	87	-70
386.20	CNG Refueling station	432,811	9.35%	40,468	3.70%	16,014	-24,454
	TOTAL Account 386	434,491	9.35%	40,625	3.71%	16,101	-24,524
	OTHER EQUIPMENT						
387.10	Cathodic Protection Equipment	1,450,657	5.21%	75,579	5.75%	83,413	7,834
387.20	Other Distribution Equipment	557,184	5.21%	29,029	1.42%	7,912	-21,117
	TOTAL Account 387	2,007,841	5.21%	104,609	4.55%	91,325	-13,284
	TOTAL Distribution Plant	151,577,594	4.46%	6,758,717	3.06%	4,640,492	-2,118,225
	General Plant						
390.00	General Structures	1,922,983	2.34%	44,998	3.73%	71,727	26,729
	OFFICE FURNITURE & EQUIPMENT						
391.10	Office Furniture & Equipment	544,275	4.05%	22,043	4.97%	27,034	4,991
391.30	Computer Equipment - PC	780,995	12.50%	97,624	26.13%	204,035	106,411
	TOTAL Account 391	1,325,269	9.03%	119,667	17.44%	231,069	111,401
	TRANSPORTATION EQUIPMENT						
392.10	Transportation Equipment (Trailers)	147,187	5.74%	8,449	4.36%	6,417	-2,031
392.20	Transportation Equipment (Cars & Trucks)	6,080,561	5.74%	349,024	21.13%	1,284,823	935,798
	TOTAL Account 392	6,227,748	5.74%	357,473	20.73%	1,291,240	933,767
393.00	Stores Equipment	186,729	0.90%	1,681	2.49%	4,658	2,978
	TOOLS, SHOP & GARAGE EQ.						
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,422	3.57%	89,087	6.62%	165,153	76,067
394.20	Tools, Shop & Garage Equip. (Unitized)	299,810	4.83%	14,481	2.40%	7,201	-7,280
394.30	Vehicle Maintenance Equipment	31,177	4.21%	1,313	5.78%	1,803	491
394.40	Vehicle Refueling Equipment	361,344	9.35%	33,786	4.72%	17,065	-16,721
	TOTAL Account 394	3,187,752	4.35%	138,666	6.00%	191,222	52,557
395.00	Laboratory Equipment	271,033	2.32%	6,288	7.67%	20,801	14,513
	POWER OPERATED EQUIPMENT						
396.10	Work Equipment (Trailers)	293,543	4.83%	14,178	5.76%	16,908	2,730
396.20	Power Operated Equipment	4,081,768	4.83%	197,149	0.00%	0	-197,149
	TOTAL Account 396	4,375,312	4.83%	211,328	0.39%	16,908	-194,419
	COMMUNICATION EQUIPMENT						
397.10	Radio Communication Equip (Fixed)	481,655	3.67%	17,677	7.37%	35,511	17,834
397.20	Radio Communication Equip (Mobile)	401,528	3.67%	14,736	7.34%	29,469	14,733
397.30	General Telephone Communication Equip.	90,518	6.56%	5,938	9.88%	8,941	3,003
397.50	Supervisory & Telemetering Equip.	124,167	6.67%	8,282	0.25%	311	-7,971
397.60	SCADA System	30,894	15.07%	4,656	0.00%	0	-4,656
397.80	Network Equipment	30,338	12.50%	3,792	26.26%	7,968	4,176
	TOTAL Account 397	1,159,100	4.75%	55,081	7.09%	82,199	27,119
398.00	Miscellaneous Equipment	145,270	0.59%	857	1.27%	1,851	994
	TOTAL General Plant	18,801,196	4.98%	936,037	10.17%	1,911,676	975,638
	TOTAL Depreciable Plant	170,378,791	4.52%	7,694,754	3.85%	6,552,168	-1,142,587
	NON-DEPRECIABLE PLANT						
374.10	Land (Distribution)	108,920					
389.00	Land & Land Rights (General)	301,149					
	Total Land	410,069					
	INTANGIBLE PLANT						
303.00	Miscellaneous Intangible Plant	477,530					
	Total Intangible Plant	477,530					
	TOTAL Non-Depreciable Plant	887,598					
	TOTAL Plant in Service	171,266,389					

Attachment 1

Montana-Dakota Utilities Company
Common Plant
MDU Settlement
Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	General Plant						
390.0	General Structures	18,048,459.30	3.76%	678,622.07	2.93%	528,819.86	-149,802.21
	OFFICE FURNITURE & EQUIPMENT						
391.1	Office Furniture & Equipment	3,716,416.91	1.48%	55,002.97	4.95%	184,032.14	129,029.17
391.2	Computer Equipment - Honeywell	93,392.30	14.17%	13,233.69	1.52%	1,416.58	-11,817.11
391.3	Computer Equipment - PC	4,212,743.17	12.50%	526,592.90	23.29%	981,147.88	454,554.98
391.5	Computer Equipment - Other	820,399.57	26.51%	217,487.93	0.46%	3,797.58	-213,690.35
	TOTAL Account 391	8,842,951.95	9.19%	812,317.49	13.24%	1,170,394.18	358,076.69
	TRANSPORTATION EQUIPMENT						
392.1	Transportation Equipment (Trailers)	251,165.84	5.74%	14,416.92	0.00%	0.00	-14,416.92
392.2	Transportation Equipment (Cars & Trucks)	4,429,701.58	5.74%	254,264.87	13.33%	590,479.22	336,214.35
	TOTAL Account 392	4,680,867.42	5.74%	268,681.79	12.61%	590,479.22	321,797.43
393.0	Stores Equipment	47,385.55	3.36%	1,592.15	2.80%	1,327.61	-264.54
	TOOLS, SHOP & GARAGE EQ.						
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026.00	3.44%	8,084.89	6.11%	14,362.50	6,277.61
394.3	Vehicle Maintenance Equipment	102,746.14	4.46%	4,582.48	-0.14%	-142.68	-4,725.16
394.4	Vehicle Refueling Equipment	838,830.77	8.42%	70,629.55	-1.09%	-9,108.58	-79,738.13
	TOTAL Account 394	1,176,602.91	7.08%	83,296.92	0.43%	5,111.24	-78,185.68
396.2	Power Operated Equipment	157,572.62	4.83%	7,610.76	2.69%	4,238.70	-3,372.06
	COMMUNICATION EQUIPMENT						
397.1	Radio Communication Equip. (Fixed)	646,187.02	4.33%	27,979.90	4.99%	32,241.83	4,261.93
397.2	Radio Communication Equip. (Mobile)	1,285,023.00	6.68%	85,839.54	4.08%	52,474.26	-33,365.28
397.3	General Telephone Communication Equip.	779,821.23	10.62%	82,817.01	8.72%	68,036.36	-14,780.65
397.5	Supervisory & Telemetering Equip.	48,295.94	0.59%	284.95	0.35%	170.00	-114.95
397.8	Network Equipment	824,948.21	12.50%	103,118.53	17.95%	148,037.04	44,918.51
	TOTAL Account 397	3,584,275.40	8.37%	300,039.93	8.40%	300,959.49	919.56
398.0	Miscellaneous Equipment	592,894.94	2.51%	14,881.66	2.41%	14,291.82	-589.84
	Sub-Total (General Plant) Amortization	**10,031,367.58**	**6.83%**	**685,535.25**	**5.09%**	**510,936.46**	**-174,598.79**
	TOTAL General Plant	37,131,010.09	5.84%	2,167,042.77	7.04%	2,615,622.12	448,579.35
	TOTAL Depreciable Plant	37,131,010.09	5.84%	2,167,042.77	7.04%	2,615,622.12	448,579.35
	Amortizable Plant						
392.3	Aircraft Equipment	1,024,349.51					
	TOTAL Amortizable Plant	1,024,349.51					
	NON-DEPRECIABLE PLANT						
389.0	Land & Land Rights (General)	1,547,408.83					
	Total Land	1,547,408.83					
	INTANGIBLE PLANT						
303.0	Miscellaneous Intangible Plant	13,553,859.20					
	Total Intangible Plant	13,553,859.20					
	TOTAL Non-Depreciable Plant	15,101,268.03					
	TOTAL Plant in Service	53,256,627.63					

Montana-Dakota Utilities Co.
Gas Division
Depreciation Rate and Expense Summary
Natural Gas and Common Utility Plant
Plant in Service as of December 31, 2001

Plant Category	Existing Composite Rate	Existing Annual Expense	Company Proposal Composite Rate	Company Proposal Annual Expense	Staff Proposal Composite Rate	Staff Proposal Annual Accrual	Recommended Composite Rate	Recommended Annual Accrual	Net Change Depr. Exp.
Gas Distribution	4.46%	$6,758,717	4.01%	$6,082,611	2.33%	$3,535,250	3.06%	$4,640,492	$(2,118,225)
Gas General	4.98%	$ 936,037	10.25%	$1,927,777	5.27%	$ 990,871	10.17%	$1,911,676	$ 975,638
Common	5.84%	$2,167,042	7.18%	$2,666,459	5.27%	$1,955,583	7.04%	$2,615,622	$ 448,579

Attachment 2

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF DEPRECIATION EXPENSE
EFFECT OF SETTLEMENT DEPRECIATION RATES
PROJECTED 2003
GAS UTILITY - NORTH DAKOTA

	Current Depreciation	Settlement Depreciation	Change
Distribution	$2,690,680	$1,805,130	($885,550)
General	119,859	215,359	95,500
General Intangible	4,538	4,538	0
Common	238,018	305,243	67,225
Common Intangible	228,014	228,014	0
Gas Plant Leased to Other	1,063	421	(642)
Acquisition Adjustment	2,819	2,819	0
Total	$3,284,991	$2,561,524	($723,467)
Clearing Accounts	217,834	551,917	334,083
Total Change	$3,502,825	$3,113,441	($389,384)

Total Reserve Change **$396,694**

Average change in reserve **$198,347**

Rate Base Effect

	% of Capital Per Order	Cost Per Order	Weighted Post-Tax Cost A x B	Income Tax Effect @39.61% Order p. 25	Weighted Pre-Tax Cost C + D
Long Term Debt	41.733%	9.180%	3.831%		3.831%
Short Term Debt	3.034%	4.542%	0.138%		0.138%
Preferred	5.114%	4.630%	0.237%	0.155%	0.392%
Common	50.119%	11.329%	5.678%	3.724%	9.402%
Total	100.0000%		9.884%		13.763%
Rate Base Increment (Col. F Total x .5)					**198,347**
Increment in Return and Taxes					**$ 27,299**

Net **($362,085)**

Attachment 3

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - CURRENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Current Depreciation Rate	Annual Depreciation	To Clearing Accounts	Clearing to Expense 4/
	Distribution Plant					
374.1	Land	$41,469				
374.2	Rights of Way	44,601	2.58%	$1,151		
375	Structures & Improvements	179,173	2.40%	4,300		
376	Mains	28,120,227	4.18%	1,175,425		
378	Meas. & Reg. Equip.-General	681,852	2.30%	15,683		
379	Meas. & Reg. Equip.-City Gate	173,090	2.74%	4,743		
380	Services	12,766,171	8.22%	1,049,379		
381	Positive Meters	12,966,012	2.58%	334,523		
383	Service Regulators	1,802,033	2.37%	42,708		
385	Ind. Meas. & Reg. Station Eqpt	369,082	1.91%	7,049		
386.1	Misc. Property on Cust. Premis	1,671	9.35%	156		
386.2	Other Property on Cust. Premi	112,613	9.35%	10,529		
387.1	Cathodic Protection Equip.	539,727	5.21%	28,120		
387.2	Other Distribution Equip.	324,654	5.21%	16,914		
	Total Distribution Plant	$58,122,375		$2,690,680		
	General Plant					
389	Land	$132,345				
390	Structures and Improvements	768,163	2.34%	17,975		
391.1	Furniture and Fixtures	191,945	4.05%	7,774		
391.3	Computer Equip. - PC	284,866	12.50%	35,608		
392.1	Trans. Equip., Non-Unitized	35,658	5.74% 2/		2,047	$1,876
392.2	Trans. Equip., Unitized	2,246,685	5.74% 2/		128,960	118,179
393	Stores Equipment	63,744	0.90%	574		
394.1	Tools,Shop&Gar. Eq.-Non-Un.	1,015,785	3.57%	36,264		
394.2	Tools,Shop&Gar. Eq.-Unitized	106,208	4.83% 2/		5,130	5,130
394.3	Vehicle Maintenance Equip.	5,668	4.21%	239		
394.4	Vehicle Refueling Equip.	83,804	9.35%	7,836		
395	Laboratory Equipment	117,959	2.32%	2,737		
396.1	Power Operated Equip.	97,778	4.83% 2/		4,723	1,594
396.2	Work Equipment Trailers	1,255,833	4.83% 2/		60,657	20,466
397.1	Radio Comm. Equip.-Fixed	104,542	3.67%	3,837		
397.2	Radio Comm. Equip.-Mobile	84,686	3.67%	3,108		
397.3	General Tele. Comm. Equip.	34,864	6.56%	2,287		
397.5	Supervisory & Tele. Equip.	1,580	6.67%	105		
397.8	Network Equipment	9,689	12.50%	1,211		
398	Miscellaneous Equipment	51,562	0.59%	304		
	Total General Plant	$6,693,364		$119,859	$201,517	$147,245
303	Intangible Plant - General	$207,216	2.19% 3/	4,538		

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - CURRENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Current Depreciation Rate	Annual Depreciation	To Clearing Accounts	Clearing to Expense 4/
	Common Plant					
389	Land	$191,572				
390	Structures and Improvements	2,270,865	3.76%	85,385		
391.1	Furniture and Fixtures	465,980	1.48%	6,897		
391.2	Computer Equip.- Bull/AS400	10,590	14.17% 1/			
391.3	Computer Equip. - PC	724,856	12.50%	90,607		
391.5	Computer Equip. - Other	113,466	26.51% 1/			
392.1	Trans. Equip., Non-Unitized	33,295	5.74% 2/		1,911	1,751
392.2	Trans. Equip., Unitized	608,336	5.74% 2/		34,918	31,999
392.3	Aircraft	243,401	15.00% 2/		36,510	36,510
393	Stores Equipment	4,744	3.36%	159		
394.1	Tools, Shop & Gar. Equip.	43,006	3.44%	1,479		
394.3	Vehicle Maint. Equip.	13,926	4.46%	621		
394.4	Vehicle Refueling Equip.	106,704	8.42%	8,984		
396.2	Work Equipment Trailers	20,203	4.83% 2/		976	329
397.1	Radio Comm. Equip.-Fixed	106,748	4.33%	4,622		
397.2	Radio Comm. Equip.-Mobile	150,883	6.68%	10,079		
397.3	General Tele. Comm. Equip.	110,151	10.62%	11,698		
397.5	Supervisory & Tele. Equip.	9,333	0.59%	55		
397.8	Network Equipment	124,138	12.50%	15,517		
398	Miscellaneous Equipment	76,293	2.51%	1,915		
	Total Common Plant	$5,428,490		$238,018	$74,315	$70,589
303	Intangible Plant - Common	2,233,244	10.21% 3/	228,014		
386.3	Gas Plant Leased to Others	11,374	9.35%	1,063		
114.2	Acquisition Adjustment	97,266		2,819		
	Total Gas Plant in Service	$72,793,329		$3,284,991	$275,832	$217,834

Summary			
Distribution	$58,133,749	$2,691,743	
General	6,693,364	119,859	147,245
General Intangible	207,216	4,538	
Common	5,428,490	238,018	70,589
Common Intangible	2,233,244	228,014	0
Acquisition Adj.	97,266	2,819	0
Total	$72,793,329	$3,284,991	$217,834

1/ Fully depreciated.
2/ Charged to a clearing account.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - CURRENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Current Depreciation Rate	Annual Depreciation	To Clearing Accounts	Clearing to Expense 4/

3/ Amortized. Rate reflects annual amortization/plant.
4/ % to clearing - Vehicles - 91.64%, work equipment -33.74% and others 100%.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - SETTLEMENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Settlement Depreciation Rate	Annual Depreciation	To Clearing Accounts	Clearing to Expense 4
	Distribution Plant					
374.1	Land	$41,469				
374.2	Rights of Way	44,601	0.75%	$335		
375	Structures & Improvements	179,173	2.57%	4,605		
376	Mains	28,120,227	1.92%	539,908		
378	Meas. & Reg. Equip.-General	681,852	2.96%	20,183		
379	Meas. & Reg. Equip.-City Gate	173,090	3.54%	6,127		
380	Services	12,766,171	5.66%	722,565		
381	Positive Meters	12,966,012	3.19%	413,616		
383	Service Regulators	1,802,033	2.59%	46,673		
385	Ind. Meas. & Reg. Station Eqpt.	369,082	3.04%	11,220		
386.1	Misc. Property on Cust. Premise	1,671	5.19%	87		
386.2	Other Property on Cust. Premise	112,613	3.70%	4,167		
387.1	Cathodic Protection Equip.	539,727	5.75%	31,034		
387.2	Other Distribution Equip.	324,654	1.42%	4,610		
	Total Distribution Plant	$58,122,375		$1,805,130		
	General Plant					
389	Land	$132,345				
390	Structures and Improvements	768,163	3.73%	28,652		
391.1	Furniture and Fixtures	191,945	4.97%	9,540		
391.3	Computer Equip. - PC	284,866	26.13%	74,435		
392.1	Trans. Equip., Non-Unitized	35,658	4.36% 2/		1,555	$1,425
392.2	Trans. Equip., Unitized	2,246,685	21.13% 2/		474,725	435,038
393	Stores Equipment	63,744	2.49%	1,587		
394.1	Tools,Shop&Gar. Eq.-Non-Un.	1,015,785	6.62%	67,245		
394.2	Tools,Shop&Gar. Eq.-Unitized	106,208	2.40% 2/		2,549	2,549
394.3	Vehicle Maintenance Equip.	5,668	5.78%	328		
394.4	Vehicle Refueling Equip.	83,804	4.72%	3,956		
395	Laboratory Equipment	117,959	7.67%	9,047		
396.1	Power Operated Equip.	97,778	5.76% 2/		5,632	1,900
396.2	Work Equipment Trailers	1,255,833	- 2/			
397.1	Radio Comm. Equip.-Fixed	104,542	7.37%	7,705		
397.2	Radio Comm. Equip.-Mobile	84,686	7.34%	6,216		
397.3	General Tele. Comm. Equip.	34,864	9.88%	3,445		
397.5	Supervisory & Tele. Equip.	1,580	0.25%	4		
397.8	Network Equipment	9,689	26.26%	2,544		
398	Miscellaneous Equipment	51,562	1.27%	655		
	Total General Plant	$6,693,364		$215,359	$484,461	$440,912
303	Intangible Plant - General	$207,216	2.19% 3/	4,538		

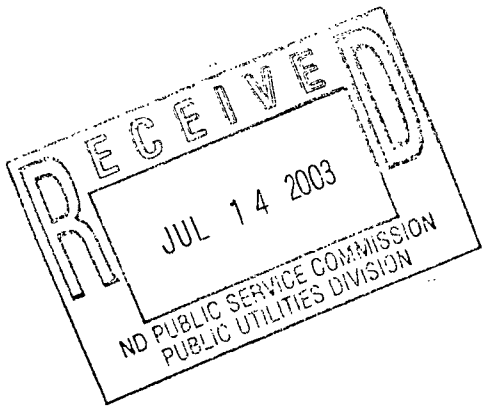
MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - SETTLEMENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Settlement Depreciation Rate	Annual Depreciation	To Clearing Accounts	Clearing to Expense 4
	Common Plant					
389	Land	$191,572				
390	Structures and Improvements	2,270,865	2.93%	66,536		
391.1	Furniture and Fixtures	465,980	4.95%	23,066		
391.2	Computer Equip.- Bull/AS400	10,590	1.52% 1/			
391.3	Computer Equip. - PC	724,856	23.29%	168,819		
391.5	Computer Equip. - Other	113,466	0.46% 1/			
392.1	Trans. Equip., Non-Unitized	33,295	- 2/			
392.2	Trans. Equip., Unitized	608,336	13.33% 2/		81,091	74,312
392.3	Aircraft	243,401	15.00% 2/		36,510	36,510
393	Stores Equipment	4,744	2.80%	133		
394.1	Tools, Shop & Gar. Equip.	43,006	6.11%	2,628		
394.3	Vehicle Maint. Equip.	13,926	-0.14%	(19)		
394.4	Vehicle Refueling Equip.	106,704	-1.09%	(1,163)		
396.2	Work Equipment Trailers	20,203	2.69% 2/		543	183
397.1	Radio Comm. Equip.-Fixed	106,748	4.99%	5,327		
397.2	Radio Comm. Equip.-Mobile	150,883	4.08%	6,156		
397.3	General Tele. Comm. Equip.	110,151	8.72%	9,605		
397.5	Supervisory & Tele. Equip.	9,333	0.35%	33		
397.8	Network Equipment	124,138	17.95%	22,283		
398	Miscellaneous Equipment	76,293	2.41%	1,839		
	Total Common Plant	$5,428,490		$305,243	$118,144	$111,005
303	Intangible Plant - Common	2,233,244	10.21% 3/	228,014		
386.3	Gas Plant Leased to Others	11,374	3.70%	421		
114.2	Acquisition Adjustment	97,266		2,819		
	Total Gas Plant in Service	$72,793,329		$2,561,524	$602,605	$551,917

Summary			
Distribution	$58,133,749	$1,805,551	
General	6,693,364	215,359	440,912
General Intangible	207,216	4,538	0
Common	5,428,490	305,243	111,005
Common Intangible	2,233,244	228,014	0
Acquisition Adj.	97,266	2,819	0
Total	$72,793,329	$2,561,524	$551,917

1/ Fully depreciated.
2/ Charged to a clearing account.
3/ Amortized. Rate reflects annual amortization/plant.
4/ % to clearing - Vehicles - 91.64%, work equipment -33.74% and others 100%.

SNAVELY KING MAJOROS O'CONNOR & LEE, INC.
ECONOMIC AND MANAGEMENT CONSULTANTS



June 30, 2003

Billed through 06/25/03

2-109-00000-003 CWK

Patrick Fahn
North Dakota Public Service Commission
State Capitol -12th Floor
Bismarck, ND 58505-0480

For services rendered and expenses incurred in connection with the depreciation phase of the gas rate increase case by Montana-Dakota Utilities, Case No. Pu-399-02-183

FEES

King, C.	17.50 hrs	120 /hr	2,100.00
Majoros, M.	6.00 hrs	120 /hr	720.00
Schneider, M.	7.00 hrs	45 /hr	315.00
TOTAL FEES	30.50		$ 3,135.00

EXPENSES

Communications, Telephone	0.81
TOTAL EXPENSES	$ 0.81

TOTAL FEES AND EXPENSES	$ 3,135.81
PREVIOUSLY BILLED	15,474.20
TOTAL BILLED TO DATE	$18,610.01
BUDGET	15,000.00
OVERRUN	$ 3,610.01
BALANCE DUE THIS INVOICE	**$0.00**

153 PU-399-02-183 Pages: 6

Bill for services rendered and expenses incurred
by Snavely King Majoros O'Connor & Lee, Inc

07/14/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

1220 L STREET, NW, SUITE 410, WASHINGTON, DC 20005-(202)371-1111, FAX (202)842-4966

1471 CASTILLO DELMAR, CAROLINA, PR 00979-(809)783-7683, FAX(809)783-7559

SK&A

Page____ of ____

SNAVELY, KING & ASSOCIATES, INC.
PROJECT ACTIVITY REPORT

Charles W. King
BWV12

For Period Beginning_____
Ending_____

Client North Dakota PSC v. MDU Billing Code 2-109

Date	Hours	Activity
6/3	7.5	Negotiations w. MDU
6/4	5.5	Develop settlement spreadsheet
6/5	1.0	Finalize settlement sheets; confer w. client
6/24	1.0	Review settlement sheets from Robinson
6/25	2.5	Review settlement; prepare impact estimate
Page Total	[illegible]	
Month Total	17.5	

SKA Form MTR-3

Name Majoros
Employee # BPM26

SK&A
ECONOMIC CONSULTANTS

For Period Beginning: **4/26/2003**
Ending: **5/25/2003**

Client: North Dakota -MDU depreciation
Billing Code: 2-109

Date	Hours	Activity
Thu, 22 May	6.00	data request
Page Total	6.00	
Month Total	6.00	

SKA Form MTR-3

SK Snavely King Majoros O'Connor & Lee

Economic and Management Consultants

1220 L St. N.W. Suite 410 Washington, D.C. 20005 (202) 371-9149

Name: Michael Schneider
Employee #

For Period Beginning: 26-May-03
and Ending: 25-Jun-03

Client: MDU
Billing Code: 2-109

Date	Hours	Activity
June 5, 2003	7.00	Gen Arm Updates
Page Total	7.00	
Month Total		
SKA Form MTR-3		

Account Number	Bill Date	ment Due Date
030 237 1228 001	APR 28, 2003	MAY 23, 2003

Location: 011 024 2327 003

SNAVELEY KING & ASSOC
1220 L ST NW STE 410
WASHINGTON DC 20005-4018

TELEPHONE NUMBER: 202 371 1111

AT&T All in One Service

Call Detail

For Customer Care: 1 877 325-0445

ITEM	DATE	TIME (hh:mm:ss)	DAY OF WEEK	PLACE	AREA CODE/ NUMBER	DURATION (hh:mm:ss)	CALL TYPE	AMOUNT
PRIMARY ACCOUNT CODE: 02104 LONG DISTANCE SERVICE								
TOTALS FOR ACCOUNT CODE: 02104						**0:11:00**		**$0.98**
PRIMARY ACCOUNT CODE: 02108								
STATE-TO-STATE CALLS								
1	4/08/03	10:23:47A	TUE	TO CHICAGO	IL 312 782-7606	3:00	DDC	0.27
2	4/08/03	10:26:04A	TUE	TO CHICAGO	IL 312 782-7606	3:00	DDC	0.27
3	4/08/03	10:54:30A	TUE	TO CHICAGO	IL 312 782-7606	2:00	DDC	0.18
4	4/08/03	11:38:02A	TUE	TO CHICAGO	IL 312 782-7606	13:00	DDC	1.16
5	4/08/03	5:35:33P	TUE	TO O FALLON	IL 618 624-4500	2:00	DDC	0.18
6	4/11/03	9:46:58A	FRI	TO CHICAGO	IL 312 782-7606	2:00	DDC	0.18
7	4/11/03	9:48:41A	FRI	TO CHICAGO	IL 312 782-7606	2:00	DDC	0.18
8	4/11/03	10:54:05A	FRI	TO CHICAGO	IL 312 782-7606	49:00	DDC	4.36
9	4/11/03	4:59:46P	FRI	TO CHICAGO	IL 312 782-7606	2:00	DDC	0.18
10	4/22/03	3:37:01P	TUE	TO CHICAGO	IL 312 782-7606	2:00	DDC	0.18
11	4/22/03	3:38:58P	TUE	TO O FALLON	IL 618 624-1110	1:00	DDC	0.09
12	4/22/03	3:39:29P	TUE	TO O FALLON	IL 618 624-4500	7:00	DDC	0.62
13	4/24/03	5:10:33P	THU	TO COLUMBUS	OH 614 292-2831	1:00	DDC	0.09
14	4/24/03	5:13:12P	THU	TO COLUMBUS	OH 614 292-4417	1:00	DDC	0.09
15	4/24/03	5:58:55P	THU	TO COLUMBUS	OH 614 292-2831	2:00	DDC	0.18
16	4/24/03	6:00:47P	THU	TO COLUMBUS	OH 614 292-2831	2:00	DDC	0.18
17	4/24/03	6:02:36P	THU	TO COLUMBUS	OH 614 292-4417	3:00	DDC	0.27
18	4/25/03	11:07:17A	FRI	TO COLUMBUS	OH 614 292-9007	1:00	DDC	0.09
19	4/25/03	3:06:43P	FRI	TO COLUMBUS	OH 614 292-2831	2:00	DDC	0.18
SUBTOTAL						**1:40:00**		**$8.93**
TOTALS FOR ACCOUNT CODE: 02108						**1:40:00**		**$8.93**
PRIMARY ACCOUNT CODE: 02109								
STATE-TO-STATE CALLS								
20	4/05/03	8:49:44A	SAT	TO SEVERN	MD 410 987-3569	1:00	DDC	0.09
21	4/07/03	4:02:56P	MON	TO BISMARCK	ND 701 222-7606	2:00	DDC	0.18
22	4/07/03	4:05:12P	MON	TO BISMARCK	ND 701 328-2410	2:00	DDC	0.18
23	4/08/03	2:54:48P	TUE	TO MALDEN	MA 781 388-8425	2:00	DDC	0.18
SUBTOTAL						**0:07:00**		**$0.63**
TOTALS FOR ACCOUNT CODE: 02109						**0:07:00**		**$0.63**
PRIMARY ACCOUNT CODE: 02110								
STATE-TO-STATE CALLS								
24	3/31/03	9:56:17A	MON	TO LANSING	MI 517 373-1123	26:00	DDC	2.31
25	4/03/03	9:41:58A	THU	TO LANSING	MI 517 373-1123	3:00	DDC	0.27
26	4/08/03	10:52:29A	TUE	TO LANSING	MI 517 373-1123	1:00	DDC	0.09
27	4/10/03	3:20:59P	THU	TO LANSING	MI 517 373-1123	2:00	DDC	0.18
28	4/15/03	9:06:40A	TUE	TO LANSING	MI 517 373-1123	2:00	DDC	0.18
29	4/18/03	9:08:50A	FRI	TO LANSING	MI 517 373-1123	25:00	DDC	2.23

AT&T Call Type Information:
DDC-Direct Dialed Call
CCS-Calling Card Station Call
CCO-Operator Handled Card Call
CCP-Calling Card Person Call
OHS-Operator Handled Station Call
ODR-Operator Handled Station Call-Dial Rate
OHP-Operator Handled Person Call
OCP-Operator Handled Person Collect Call

Account Number	Bill Date	Payment Due Date
030 237 1228 001	MAY 28, 2003	JUN 23, 2003

Location: 011 024 2327 003

SNAVELEY KING & ASSOC
1220 L ST NW STE 410
WASHINGTON DC 20005-4018

TELEPHONE NUMBER: 202 371 111

AT&T All in One Service

Call Detail

For Customer Care: 1 877 325-0445

ITEM	DATE	TIME (hh:mm:ss)	DAY OF WEEK	PLACE	AREA CODE/ NUMBER	DURATION (hh:mm:ss)	CALL TYPE	AMOUNT
LONG DISTANCE SERVICE								
PRIMARY ACCOUNT CODE: 02109								
STATE-TO-STATE CALLS								
1	5/02/03	1:54:45P	FRI	TO BISMARCK	ND 701 328-4088	1:00	DDC	0.09
2	5/02/03	1:57:07P	FRI	TO BISMARCK	ND 701 328-4077	1:00	DDC	0.09
SUBTOTAL						0:02:00		$0.18
TOTALS FOR ACCOUNT CODE: 02109						0:02:00		$0.18
PRIMARY ACCOUNT CODE: 02111								
STATE-TO-STATE CALLS								
3	5/01/03	3:50:50P	THU	TO ATLANTA	GA 404 656-0980	1:00	DDC	0.09
SUBTOTAL						0:01:00		$0.09
TOTALS FOR ACCOUNT CODE: 02111						0:01:00		$0.09
PRIMARY ACCOUNT CODE: 02992								
STATE-TO-STATE CALLS								
4	4/29/03	8:21:44A	TUE	TO TALLAHASSE	FL 850 413-6770	2:00	DDC	0.18
5	5/12/03	5:03:49P	MON	TO OCEAN CITY	MD 410 524-5577	1:00	DDC	0.09
6	5/15/03	2:19:51P	THU	TO INDIANAPLS	IN 317 232-2709	2:00	DDC	0.18
7	5/15/03	2:21:32P	THU	TO INDIANAPLS	IN 317 233-2010	3:00	DDC	0.27
8	5/15/03	3:58:10P	THU	TO CHASE	MD 410 335-6489	2:00	DDC	0.18
9	5/20/03	11:34:11A	TUE	TO NO PHOENIX	AZ 602 274-9944	6:00	DDC	0.53
SUBTOTAL						0:16:00		$1.43
TOTALS FOR ACCOUNT CODE: 02992						0:16:00		$1.43
PRIMARY ACCOUNT CODE: 03070								
STATE-TO-STATE CALLS								
10	5/22/03	2:55:30P	THU	TO CEDAR RPDS	IA 319 790-7767	1:00	DDC	0.09
SUBTOTAL						0:01:00		$0.09
TOTALS FOR ACCOUNT CODE: 03070						0:01:00		$0.09
PRIMARY ACCOUNT CODE: 03238								
STATE-TO-STATE CALLS								
11	5/08/03	3:03:21P	THU	TO PITTSBURGH	PA 412 393-1502	3:00	DDC	0.27
12	5/08/03	3:36:04P	THU	TO PITTSBURGH	PA 412 350-6109	1:00	DDC	0.09
13	5/08/03	4:22:07P	THU	TO JOHNSTOWN	PA 814 533-8430	2:00	DDC	0.18
14	5/08/03	4:24:49P	THU	TO SPRINGDALE	PA 724 275-1501	2:00	DDC	0.18
SUBTOTAL						0:08:00		$0.72

AT&T Call Type Information:
DDC-Direct Dialed Call
CCS-Calling Card Station Call
CCO-Operator Handled Card Call
CCP-Calling Card Person Call
OHS-Operator Handled Station Call
ODR-Operator Handled Station Call-Dial Rate
OHP-Operator Handled Person Call
OCP-Operator Handled Person Collect Call

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MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS DIVISION
NDPSC DEPRECIATION INVESTIGATION

PRIMARY ISSUES OF DISAGREEMENT BETWEEN MDU AND PSC STAFF WITNESSES:

- Treatment of Net Negative Salvage.

- Determination of Average Service Lives.

Existing & Proposed Depreciation Accruals – Total Company

	Existing	Company Proposal	Staff Proposal
Gas Distribution	6,758,717	6,082,612	3,535,230
Gas General	936,037	1,927,778	990,871
Total	7,694,754	8,010,390	4,526,101
Common Plant	2,167,042	2,666,460	1,955,583

152 PU-399-02-183 Pages: 4
Summary of Settlement Agreement
by Montana-Dakota Utilities Co., a Division of MDU R
07/09/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

Net Negative Salvage Issues –

- MDU witness applied an inflation factor to estimate future removal costs in determining net negative salvage ratios.

- Staff witness applied a discount factor to current removal costs in determining future net negative salvage costs.

  - Both methodologies depart from "conventional approach" of determining net negative salvage.

Settlement Position –

- Used "conventional approach" in calculating net negative salvage based on current costs.

- Conventional approach has traditionally been used to determine net negative salvage for depreciation rates approved or accepted by NDPSC.

- Settlement does not establish precedent and preserves the right of both parties to advocate, and for the Commission to consider, appropriate methodologies for determining net negative salvage in future proceedings.

Average Lives Issues –

- Accounts having the greatest $$ impact are:

	MDU Proposed Lives	Staff Proposed Lives	Settlement Position
Mains	45	58	54
Services	40	55	40

- Differences reflect professional differences of opinion.
- Settlement lives for Mains and Services are consistent with industry averages.

Settlement Impact –

TOTAL COMPANY
December 31, 2001 Plant in Service

	Existing	Settlement	Change
Gas Distribution	6,758,717	4,640,492	(2,118,225)
Gas General	936,037	1,911,676	975,639
Total	7,694,754	6,552,168	(1,142,586)
Common	2,167,042	2,615,622	448,579

North Dakota Retail Rate Impact – ($362,085)

* See Settlement Attachment 3

ZUGER KIRMIS & SMITH

COUNSELORS AND ATTORNEYS AT LAW

Lyle W. Kirmis
Lance D. Schreiner, P.C.
James S. Hill, P.C.
Patrick J. Ward
Rebecca S. Thiem, P.C.
Daniel S. Kuntz, P.C.
Jerry W. Evenson, P.C.
Lawrence A. Dopson
Lawrence E. King, P.C.
Tracy Vigness Kolb, P.C.
Shawnda R. Reid
Constance N. Hofland
Paul R. Sanderson

316 North Fifth Street
Provident Building
P.O. Box 1695
Bismarck, ND 58502-1695
(701) 223-2711
fax (701) 223-7387
www.zkslaw.com
email: zkslaw@zkslaw.com

Of Counsel
John A. Zuger

Thomas O. Smith
1944-2001

RECEIVED
JUL - 8 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

July 8, 2003

Mr. Jon Mielke
Executive Secretary
ND Public Service Commission
600 East Boulevard Avenue -- 12th Floor
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co. Depreciation Study – Case No. PU-399-02-183

Dear Mr. Mielke:

Enclosed for filing are the original and seven copies of the a Settlement Agreement entered into by Montana-Dakota Utilities Co. and the Staff of the North Dakota Public Service Commission. Acceptance of this Settlement Agreement by the Public Service Commission would resolve all outstanding continued issues in this case. The parties to the Settlement Agreement request that the Agreement be brought to the attention of the Public Service Commission for consideration at the informal hearing on this matter scheduled for July 9, 2003.

Please contact me or Bill Binek if you have any questions regarding this Agreement.

Sincerely,

Daniel S. Kuntz

Enclosures

c: Don Ball
Bill Binek

151 PU-399-02-183 Pages: 1
Cover letter re Settlement Agreement
by Montana-Dakota Utilities Co., a Division of MDU R
07/08/2003 CC: Comm Legal Illona, Pat, Jerry Mike

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NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.) Case No. PU-399-02-183
Depreciation Study)

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into by and between Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company") and the Staff of the North Dakota Public Service Commission ("Staff"). This Settlement Agreement resolves all outstanding continued issues in this case in a manner consistent with the public interest and will result in just and reasonable depreciation rates and expense accruals for the Company's natural gas distribution operations in North Dakota.

PROCEDURAL HISTORY

1. On April 12, 2002, Montana-Dakota filed an application for an increase in its North Dakota retail natural gas rates based on a 2003 projected test year. The North Dakota Public Service Commission ("Commission") suspended Montana-Dakota's rate filing and set the matter for investigation and hearing. The disputed issues between Montana-Dakota and the Staff included the proper depreciation rates and depreciation expenses for the test year. The Staff's witness recommended that the test year depreciation expenses proposed by the Company be reduced. The Company's witness maintained that no depreciation rate adjustments should be entertained until a depreciation study being conducted by the Company was completed and reviewed.

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Settlement Agreement
by Montana-Dakota Utilities Co., a Division of MDU R
07/08/2003 CC. Comm Legal Illona, Pat, Jerry Mike .

Montana-Dakota asked the Commission to defer any consideration of the depreciation issue until Montana-Dakota's new depreciation study was complete, Montana-Dakota agreed to submit the new depreciation study for review by January 31, 2003 as a continued issue in this proceeding subject to the standard and customary contested case process with all parties having rights of discovery, testimony, rebuttal testimony, hearing and briefing.

2. In its Order issued December 18, 2002, the Commission approved continuation of the depreciation issue. Montana-Dakota was directed to file its depreciation study as soon as possible but no later than January 31, 2003. Any resulting changes in depreciation expense ordered by the Commission at the conclusion of the review of the depreciation study would be reflected in rates on a prospective basis.

3. On January 31, 2003, Montana-Dakota filed depreciation studies prepared by AUS Consultants related to Montana-Dakota's common and gas division utility plant.

4. On March 12, 2003, the Commission issued a Notice of Hearing and Procedural Schedule setting the following issues for consideration on Montana-Dakota's depreciation studies:

1. What is the value of Montana-Dakota's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is the appropriate treatment of plant retirement costs?
3. What rates and charges are necessary to provide a just and reasonable rate of return on Montana-Dakota's property, used and useful, for the service and convenience of the public in North Dakota?

A hearing on the above issues was scheduled for April 22, 2003. On April 23, 2003, the Commission rescheduled the hearing to July 1, 2003.

5. The Company's depreciation studies indicated the Company's existing depreciation rates, applied to total system-wide depreciable gas division utility plant in service as of December 31, 2001 resulted in an annual depreciation expense of $7,694,754. In comparison, application of the study's proposed depreciation rates to the same depreciable plant in service as of December 31, 2001 would result in an annual depreciation expense of $8,010,389; an increase of $315,635 from existing rates. The composite annual depreciation rate under the existing rates is 4.52% while the Company's study recommended a proposed composite depreciation rate of 4.70%.

6. For common utility plant, the studies indicated the application of existing rates to total system-wide depreciable common plant in service as of December 31, 2001 resulted in an annual depreciation expense of $2,167,043. Application of the proposed depreciation rates to the total system-wide depreciable common plant in service as of December 31, 2001 would result in an annual depreciation expense of $2,666,460; an increase of $499,417 from the existing rates. The composite annual depreciation rate for common plant under the existing rates is 5.84%, while the studies proposed composite depreciation rate for common plant would be 7.18%.

7. On April 7, 2003, the consultant for the Staff, Charles W. King, filed direct testimony reviewing and critiquing the depreciation study prepared by AUS Consultants. Mr. King also recommended alternative depreciation rates for the gas division and common utility plant of Montana-Dakota. The following is a comparison of the Company's existing

depreciation rates as well as those recommended by the Company and the Staff:

Plant Category	Existing Composite Rate	Existing Annual Expense	Company Proposal Composite Rate	Company Proposal Annual Expense	Staff Proposal Composite Rate	Staff Proposal Annual Accrual
Gas Distribution	4.46%	$6,758,717	4.01%	$6,082,611	2.33%	$3,535,250
Gas General	4.98%	$ 936,037	10.25%	$1,927,777	5.27%	$ 990,871
Common	5.84%	$2,167,042	7.18%	$2,666,459	5.27%	$1,955,583

8. On April 28, 2003, the Company filed rebuttal testimony of Earl M. Robinson responding to the testimony and recommendations of Mr. King.

9. Following the analysis of the depreciation studies and the testimony of the parties respective witnesses, settlement discussions were held between the Staff and Company representatives in accordance with the Commission's proposed settlement guidelines (July 1994). As a result of those discussions, the parties have reached this Settlement Agreement. The parties agree the Settlement Agreement resolves all issues in the proceeding in a manner consistent with applicable law and the settlement guidelines.

10. The Settlement Agreement is supported by the administrative record. Accordingly, the parties jointly recommend the Commission issue an Order: (a) approving this Settlement Agreement in its entirety, without conditions or modifications; (b) approving the depreciation rates for the Company's natural gas distribution and common utility plant; and (c) directing the Company to file revised rate schedules reflecting the impact of the proposed depreciation rates on the Company's existing natural gas retail rates in North Dakota and implementing changes in its natural gas retail rates consistent with this

Settlement Agreement.

TERMS OF SETTLEMENT AGREEMENT

Attachment 1 is a schedule by functional plant categories and accounts of the existing and agreed depreciation rates and the annual system-wide depreciation expenses based upon depreciable plant in service at December 31, 2001. A comparison of the existing rates and expenses, the Company proposal, the Staff proposal, and the recommended depreciation rates and annual expense accruals based on December 31, 2001 system-wide plant in service is shown in Attachment 2.

Staff and Montana-Dakota agree and recommend that the Commission approve the recommended depreciation rates on Attachment 1.

The recommended depreciation rates were arrived through negotiations based upon the studies and testimony provided by the expert consultants for the Staff and the Company. Although the Staff and the Company agree and recommend the depreciation rates set forth on Attachment 1, the parties do not adopt or recommend as part of this Settlement Agreement the amount or a methodology for determining net salvage and average service lives for the various plant accounts. Nothing in this Settlement Agreement shall limit the authority of the Commission to establish, or the Staff and the Company to advocate, in future proceedings, the appropriate methodology or the appropriate amounts of net salvage and average service lives for the various plant accounts.

EFFECTIVE DATE OF REVISED RATES

Subject to approval by the Commission of this Settlement Agreement, the revised depreciation rates and the resulting retail rate change will become effective September 1,

2003.

RETAIL RATE ADJUSTMENT

Upon approval of the Settlement Agreement by the Commission, the Company shall file revised tariff sheets reflecting changes to its North Dakota retail natural gas rates based upon the depreciation rate changes which is a reduction in annual revenues of $362,085. Attachment 3 shows the calculation of the North Dakota natural gas retail rate reduction to reflect the recommended depreciated rates and expense accruals. The rate reduction shall be applied to the rate classes in the same manner as the increase that was effective with service rendered December 12, 2002. The applicable change will be implemented as a reduction to the distribution delivery charge component of the rate. The revised tariff sheets shall be filed not less than ten (10) days prior to the effective date.

OTHER TERMS AND CONDITIONS

A. Basis of Settlement.

It is agreed this Settlement Agreement contains negotiated depreciation rates and accrual amounts subject to approval by the Commission. The Settlement Agreement does not establish any principle or precedent regarding the methodology for establishing depreciation rates.

B. Effect of the Settlement Negotiations.

It is understood and agreed that all offers of settlement and discussions related to this Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Public Service Commission does not approve this Settlement Agreement, it shall not constitute

part of the record in this proceeding and no part thereof may used by any party for any purpose in this proceeding or otherwise.

C. Applicability and Scope.

This Settlement Agreement shall be binding on the parties hereto, and their successors, assigns, agents and representatives. Consistent with the Commission's 1994 proposed settlement guidelines, this Settlement Agreement does not set policy or overturn precedent.

D. Effective Date.

This Settlement Agreement shall be effective on the date of final Commission Order approving the Settlement Agreement with the revised depreciation rates and corresponding revised retail rates effective on the dates specified herein. If the Commission Order modifies or conditions approval, this Settlement Agreement shall be deemed terminated if either party files a letter with the Commission within 3 (three) business days of notice of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

Dated this 8th day of July, 2003.

Montana-Dakota Utilities Co.

By: Donald R. Ball
Its: Assistant Vice President - Regulatory Affairs

Dated this 8th day of July, 2003.

North Dakota Public Service Commission

By: [signature]
Chief Counsel

Montana-Dakota Utilities Company
Gas Division
SETTLEMENT POSITION
Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	Distribution Plant						
374.20	Rights of Way	89,641	2.58%	2,313	0.75%	672	-1,640
375.00	Distr. Meas & Reg Station Structures	521,210	2.40%	12,509	2.57%	13,395	886
376.00	Mains	78,334,154	4.05%	3,172,533	1.92%	1,504,016	-1,668,517
378.00	Meas & Reg Station Equip-General	1,367,334	2.30%	31,449	2.96%	40,473	9,024
379.00	Meas & Reg Station Equip-City Gate	1,009,137	2.74%	27,650	3.54%	35,723	8,073
380.00	Services	32,476,717	7.60%	2,468,231	5.66%	1,838,182	-630,048
381.00	Meters	30,462,008	2.58%	785,920	3.19%	971,738	185,818
383.00	Service Regulators	4,296,862	2.37%	101,836	2.59%	111,289	9,453
385.00	Industrial Meas. & Reg. Station Equipment	578,200	1.91%	11,044	3.04%	17,577	6,534
						4,533,066	
	MISCELLANEOUS EQUIPMENT						
386.10	Miscellaneous Property on Customers Premise	1,680	9.35%	157	5.19%	87	-70
386.20	CNG Refueling station	432,811	9.35%	40,468	3.70%	16,014	-24,454
	TOTAL Account 386	434,491	9.35%	40,625	3.71%	16,101	-24,524
	OTHER EQUIPMENT						
387.10	Cathodic Protection Equipment	1,450,657	5.21%	75,579	5.75%	83,413	7,834
387.20	Other Distribution Equipment	557,184	5.21%	29,029	1.42%	7,912	-21,117
	TOTAL Account 387	2,007,841	5.21%	104,609	4.55%	91,325	-13,284
	TOTAL Distribution Plant	151,577,594	4.46%	6,758,717	3.06%	4,640,492	-2,118,225
	General Plant						
390.00	General Structures	1,922,983	2.34%	44,998	3.73%	71,727	26,729
	OFFICE FURNITURE & EQUIPMENT						
391.10	Office Furniture & Equipment	544,275	4.05%	22,043	4.97%	27,034	4,991
391.30	Computer Equipment - PC	780,995	12.50%	97,624	26.13%	204,035	106,411
	TOTAL Account 391	1,325,269	9.03%	119,667	17.44%	231,069	111,401
	TRANSPORTATION EQUIPMENT						
392.10	Transportation Equipment (Trailers)	147,187	5.74%	8,449	4.36%	6,417	-2,031
392.20	Transportation Equipment (Cars & Trucks)	6,080,561	5.74%	349,024	21.13%	1,284,823	935,798
	TOTAL Account 392	6,227,748	5.74%	357,473	20.73%	1,291,240	933,767
393.00	Stores Equipment	186,729	0.90%	1,681	2.49%	4,658	2,978
	TOOLS, SHOP & GARAGE EQ.						
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,422	3.57%	89,087	6.62%	165,153	76,067
394.20	Tools, Shop & Garage Equip. (Unitized)	299,810	4.83%	14,481	2.40%	7,201	-7,280
394.30	Vehicle Maintenance Equipment	31,177	4.21%	1,313	5.78%	1,803	491
394.40	Vehicle Refueling Equipment	361,344	9.35%	33,786	4.72%	17,065	-16,721
	TOTAL Account 394	3,187,752	4.35%	138,666	6.00%	191,222	52,557
395.00	Laboratory Equipment	271,033	2.32%	6,288	7.67%	20,801	14,513
	POWER OPERATED EQUIPMENT						
396.10	Work Equipment (Trailers)	293,543	4.83%	14,178	5.76%	16,908	2,730
396.20	Power Operated Equipment	4,081,768	4.83%	197,149	0.00%	0	-197,149
	TOTAL Account 396	4,375,312	4.83%	211,328	0.39%	16,908	-194,419
	COMMUNICATION EQUIPMENT						
397.10	Radio Communication Equip. (Fixed)	481,655	3.67%	17,677	7.37%	35,511	17,834
397.20	Radio Communication Equip. (Mobile)	401,528	3.67%	14,736	7.34%	29,469	14,733
397.30	General Telephone Communication Equip.	90,518	6.56%	5,938	9.88%	8,941	3,003
397.50	Supervisory & Telemetering Equip.	124,167	6.67%	8,282	0.25%	311	-7,971
397.60	SCADA System	30,894	15.07%	4,656	0.00%	0	-4,656
397.80	Network Equipment	30,338	12.50%	3,792	26.26%	7,968	4,176
	TOTAL Account 397	1,159,100	4.75%	55,081	7.09%	82,199	27,119
398.00	Miscellaneous Equipment	145,270	0.59%	857	1.27%	1,851	994
	TOTAL General Plant	18,801,196	4.98%	936,037	10.17%	1,911,676	975,638
	TOTAL Depreciable Plant	170,378,791	4.52%	7,694,754	3.85%	6,552,168	-1,142,587
	NON-DEPRECIABLE PLANT						
374.10	Land (Distribution)	108,920					
389.00	Land & Land Rights (General)	301,149					
	Total Land	410,069					
	INTANGIBLE PLANT						
303.00	Miscellaneous Intangible Plant	477,530					
	Total Intangible Plant	477,530					
	TOTAL Non-Depreciable Plant	887,598					
	TOTAL Plant in Service	171,266,389					

Attachment 1

Montana-Dakota Utilities Company
Common Plant
MDU Settlement
Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	General Plant						
390.0	General Structures	18,048,459.30	3.76%	678,622.07	2.93%	528,819.86	-149,802.21
	OFFICE FURNITURE & EQUIPMENT						
391.1	Office Furniture & Equipment	3,716,416.91	1.48%	55,002.97	4.95%	184,032.14	129,029.17
391.2	Computer Equipment - Honeywell	93,392.30	14.17%	13,233.69	1.52%	1,416.58	-11,817.11
391.3	Computer Equipment - PC	4,212,743.17	12.50%	526,592.90	23.29%	981,147.88	454,554.98
391.5	Computer Equipment - Other	820,399.57	26.51%	217,487.93	0.46%	3,797.58	-213,690.35
	TOTAL Account 391	8,842,951.95	9.19%	812,317.49	13.24%	1,170,394.18	358,076.69
	TRANSPORTATION EQUIPMENT						
392.1	Transportation Equipment (Trailers)	251,165.84	5.74%	14,416.92	0.00%	0.00	-14,416.92
392.2	Transportation Equipment (Cars & Trucks)	4,429,701.58	5.74%	254,264.87	13.33%	590,479.22	336,214.35
	TOTAL Account 392	4,680,867.42	5.74%	268,681.79	12.61%	590,479.22	321,797.43
393.0	Stores Equipment	47,385.55	3.36%	1,592.15	2.80%	1,327.61	-264.54
	TOOLS, SHOP & GARAGE EQ.						
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026.00	3.44%	8,084.89	6.11%	14,362.50	6,277.61
394.3	Vehicle Maintenance Equipment	102,746.14	4.46%	4,582.48	-0.14%	-142.68	-4,725.16
394.4	Vehicle Refueling Equipment	838,830.77	8.42%	70,629.55	-1.09%	-9,108.58	-79,738.13
	TOTAL Account 394	1,176,602.91	7.08%	83,296.92	0.43%	5,111.24	-78,185.68
396.2	Power Operated Equipment	157,572.62	4.83%	7,610.76	2.69%	4,238.70	-3,372.06
	COMMUNICATION EQUIPMENT						
397.1	Radio Communication Equip. (Fixed)	646,187.02	4.33%	27,979.90	4.99%	32,241.83	4,261.93
397.2	Radio Communication Equip. (Mobile)	1,285,023.00	6.68%	85,839.54	4.08%	52,474.26	-33,365.28
397.3	General Telephone Communication Equip.	779,821.23	10.62%	82,817.01	8.72%	68,036.36	-14,780.65
397.5	Supervisory & Telemetering Equip.	48,295.94	0.59%	284.95	0.35%	170.00	-114.95
397.8	Network Equipment	824,948.21	12.50%	103,118.53	17.95%	148,037.04	44,918.51
	TOTAL Account 397	3,584,275.40	8.37%	300,039.93	8.40%	300,959.49	919.56
398.0	Miscellaneous Equipment	592,894.94	2.51%	14,881.66	2.41%	14,291.82	-589.84
	Sub-Total (General Plant) Amortization	**10,031,367.58**	**6.83%**	**685,535.25**	**5.09%**	**510,936.46**	**-174,598.79**
	TOTAL General Plant	37,131,010.09	5.84%	2,167,042.77	7.04%	2,615,622.12	448,579.35
	TOTAL Depreciable Plant	37,131,010.09	5.84%	2,167,042.77	7.04%	2,615,622.12	448,579.35
	Amortizable Plant						
392.3	Aircraft Equipment	1,024,349.51					
	TOTAL Amortizable Plant	1,024,349.51					
	NON-DEPRECIABLE PLANT						
389.0	Land & Land Rights (General)	1,547,408.83					
	Total Land	1,547,408.83					
	INTANGIBLE PLANT						
303.0	Miscellaneous Intangible Plant	13,553,859.20					
	Total Intangible Plant	13,553,859.20					
	TOTAL Non-Depreciable Plant	15,101,268.03					
	TOTAL Plant in Service	53,256,627.63					

Montana-Dakota Utilities Co.
Gas Division
Depreciation Rate and Expense Summary
Natural Gas and Common Utility Plant
Plant in Service as of December 31, 2001

Plant Category	Existing Composite Rate	Existing Annual Expense	Company Proposal Composite Rate	Company Proposal Annual Expense	Staff Proposal Composite Rate	Staff Proposal Annual Accrual	Recommended Composite Rate	Recommended Annual Accrual	Net Change Depr. Exp.
Gas Distribution	4.46%	$6,758,717	4.01%	$6,082,611	2.33%	$3,535,250	3.06%	$4,640,492	$(2,118,2
Gas General	4.98%	$ 936,037	10.25%	$1,927,777	5.27%	$ 990,871	10.17%	$1,911,676	$ 975,638
Common	5.84%	$2,167,042	7.18%	$2,666,459	5.27%	$1,955,583	7.04%	$2,615,622	$ 448,579

Attachment 2

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF DEPRECIATION EXPENSE
EFFECT OF SETTLEMENT DEPRECIATION RATES
PROJECTED 2003
GAS UTILITY - NORTH DAKOTA

	Current Depreciation	Settlement Depreciation	Change
Distribution	$2,690,680	$1,805,130	($885,550)
General	119,859	215,359	95,500
General Intangible	4,538	4,538	0
Common	238,018	305,243	67,225
Common Intangible	228,014	228,014	0
Gas Plant Leased to Other	1,063	421	(642)
Acquisition Adjustment	2,819	2,819	0
Total	$3,284,991	$2,561,524	($723,467)
Clearing Accounts	217,834	551,917	334,083
Total Change	$3,502,825	$3,113,441	($389,384)

Total Reserve Change **$396,694**

Average change in reserve **$198,347**

Rate Base Effect

	% of Capital Per Order	Cost Per Order	Weighted Post-Tax Cost A x B	Income Tax Effect @39.61% Order p. 25	Weighted Pre-Tax Cost C + D
Long Term Debt	41.733%	9.180%	3.831%		3.831%
Short Term Debt	3.034%	4.542%	0.138%		0.138%
Preferred	5.114%	4.630%	0.237%	0.155%	0.392%
Common	50.119%	11.329%	5.678%	3.724%	9.402%
Total	100.0000%		9.884%		13.763%
Rate Base Increment (Col. F Total x .5)					**198,347**
Increment in Return and Taxes					**$ 27,299**

Net **($362,085)**

Attachment 3

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - CURRENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Current Depreciation Rate	Annual Depreciation	To Clearing Accounts	Clearing to Expense 4/
	Distribution Plant					
374.1	Land	$41,469				
374.2	Rights of Way	44,601	2.58%	$1,151		
375	Structures & Improvements	179,173	2.40%	4,300		
376	Mains	28,120,227	4.18%	1,175,425		
378	Meas. & Reg. Equip.-General	681,852	2.30%	15,683		
379	Meas. & Reg. Equip.-City Gate	173,090	2.74%	4,743		
380	Services	12,766,171	8.22%	1,049,379		
381	Positive Meters	12,966,012	2.58%	334,523		
383	Service Regulators	1,802,033	2.37%	42,708		
385	Ind. Meas. & Reg. Station Eqpt	369,082	1.91%	7,049		
386.1	Misc. Property on Cust. Premis	1,671	9.35%	156		
386.2	Other Property on Cust. Premi	112,613	9.35%	10,529		
387.1	Cathodic Protection Equip.	539,727	5.21%	28,120		
387.2	Other Distribution Equip.	324,654	5.21%	16,914		
	Total Distribution Plant	$58,122,375		$2,690,680		
	General Plant					
389	Land	$132,345				
390	Structures and Improvements	768,163	2.34%	17,975		
391.1	Furniture and Fixtures	191,945	4.05%	7,774		
391.3	Computer Equip. - PC	284,866	12.50%	35,608		
392.1	Trans. Equip., Non-Unitized	35,658	5.74% 2/		2,047	$1,876
392.2	Trans. Equip., Unitized	2,246,685	5.74% 2/		128,960	118,179
393	Stores Equipment	63,744	0.90%	574		
394.1	Tools,Shop&Gar. Eq.-Non-Un.	1,015,785	3.57%	36,264		
394.2	Tools,Shop&Gar. Eq.-Unitized	106,208	4.83% 2/		5,130	5,130
394.3	Vehicle Maintenance Equip.	5,668	4.21%	239		
394.4	Vehicle Refueling Equip.	83,804	9.35%	7,836		
395	Laboratory Equipment	117,959	2.32%	2,737		
396.1	Power Operated Equip.	97,778	4.83% 2/		4,723	1,594
396.2	Work Equipment Trailers	1,255,833	4.83% 2/		60,657	20,466
397.1	Radio Comm. Equip.-Fixed	104,542	3.67%	3,837		
397.2	Radio Comm. Equip.-Mobile	84,686	3.67%	3,108		
397.3	General Tele. Comm. Equip.	34,864	6.56%	2,287		
397.5	Supervisory & Tele. Equip.	1,580	6.67%	105		
397.8	Network Equipment	9,689	12.50%	1,211		
398	Miscellaneous Equipment	51,562	0.59%	304		
	Total General Plant	$6,693,364		$119,859	$201,517	$147,245
303	Intangible Plant - General	$207,216	2.19% 3/	4,538		

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - CURRENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Current Depreciation Rate	Annual Depreciation	To Clearing Accounts	Clearing to Expense 4/
	Common Plant					
389	Land	$191,572				
390	Structures and Improvements	2,270,865	3.76%	85,385		
391.1	Furniture and Fixtures	465,980	1.48%	6,897		
391.2	Computer Equip.- Bull/AS400	10,590	14.17% 1/			
391.3	Computer Equip. - PC	724,856	12.50%	90,607		
391.5	Computer Equip. - Other	113,466	26.51% 1/			
392.1	Trans. Equip., Non-Unitized	33,295	5.74% 2/		1,911	1,751
392.2	Trans. Equip., Unitized	608,336	5.74% 2/		34,918	31,999
392.3	Aircraft	243,401	15.00% 2/		36,510	36,510
393	Stores Equipment	4,744	3.36%	159		
394.1	Tools, Shop & Gar. Equip.	43,006	3.44%	1,479		
394.3	Vehicle Maint. Equip.	13,926	4.46%	621		
394.4	Vehicle Refueling Equip.	106,704	8.42%	8,984		
396.2	Work Equipment Trailers	20,203	4.83% 2/		976	329
397.1	Radio Comm. Equip.-Fixed	106,748	4.33%	4,622		
397.2	Radio Comm. Equip.-Mobile	150,883	6.68%	10,079		
397.3	General Tele. Comm. Equip.	110,151	10.62%	11,698		
397.5	Supervisory & Tele. Equip.	9,333	0.59%	55		
397.8	Network Equipment	124,138	12.50%	15,517		
398	Miscellaneous Equipment	76,293	2.51%	1,915		
	Total Common Plant	$5,428,490		$238,018	$74,315	$70,589
303	Intangible Plant - Common	2,233,244	10.21% 3/	228,014		
386.3	Gas Plant Leased to Others	11,374	9.35%	1,063		
114.2	Acquisition Adjustment	97,266		2,819		
	Total Gas Plant in Service	$72,793,329		$3,284,991	$275,832	$217,834

Summary			
Distribution	$58,133,749	$2,691,743	
General	6,693,364	119,859	147,245
General Intangible	207,216	4,538	
Common	5,428,490	238,018	70,589
Common Intangible	2,233,244	228,014	0
Acquisition Adj.	97,266	2,819	0
Total	$72,793,329	$3,284,991	$217,834

1/ Fully depreciated.
2/ Charged to a clearing account.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - CURRENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Current Depreciation Rate	Annual Depreciation	To Clearing Accounts	Clearing to Expense 4/

3/ Amortized. Rate reflects annual amortization/plant.

4/ % to clearing - Vehicles - 91.64%, work equipment -33.74% and others 100%.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - SETTLEMENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Settlement Depreciation Rate		Annual Depreciation	To Clearing Accounts	Clearing to Expense 4
	Distribution Plant						
374.1	Land	$41,469					
374.2	Rights of Way	44,601	0.75%		$335		
375	Structures & Improvements	179,173	2.57%		4,605		
376	Mains	28,120,227	1.92%		539,908		
378	Meas. & Reg. Equip.-General	681,852	2.96%		20,183		
379	Meas. & Reg. Equip.-City Gate	173,090	3.54%		6,127		
380	Services	12,766,171	5.66%		722,565		
381	Positive Meters	12,966,012	3.19%		413,616		
383	Service Regulators	1,802,033	2.59%		46,673		
385	Ind. Meas. & Reg. Station Eqpt.	369,082	3.04%		11,220		
386.1	Misc. Property on Cust. Premise	1,671	5.19%		87		
386.2	Other Property on Cust. Premise	112,613	3.70%		4,167		
387.1	Cathodic Protection Equip.	539,727	5.75%		31,034		
387.2	Other Distribution Equip.	324,654	1.42%		4,610		
	Total Distribution Plant	$58,122,375			$1,805,130		
	General Plant						
389	Land	$132,345					
390	Structures and Improvements	768,163	3.73%		28,652		
391.1	Furniture and Fixtures	191,945	4.97%		9,540		
391.3	Computer Equip. - PC	284,866	26.13%		74,435		
392.1	Trans. Equip., Non-Unitized	35,658	4.36%	2/		1,555	$1,425
392.2	Trans. Equip., Unitized	2,246,685	21.13%	2/		474,725	435,038
393	Stores Equipment	63,744	2.49%		1,587		
394.1	Tools,Shop&Gar. Eq.-Non-Un.	1,015,785	6.62%		67,245		
394.2	Tools,Shop&Gar. Eq.-Unitized	106,208	2.40%	2/		2,549	2,549
394.3	Vehicle Maintenance Equip.	5,668	5.78%		328		
394.4	Vehicle Refueling Equip.	83,804	4.72%		3,956		
395	Laboratory Equipment	117,959	7.67%		9,047		
396.1	Power Operated Equip.	97,778	5.76%	2/		5,632	1,900
396.2	Work Equipment Trailers	1,255,833	-	2/			
397.1	Radio Comm. Equip.-Fixed	104,542	7.37%		7,705		
397.2	Radio Comm. Equip.-Mobile	84,686	7.34%		6,216		
397.3	General Tele. Comm. Equip.	34,864	9.88%		3,445		
397.5	Supervisory & Tele. Equip.	1,580	0.25%		4		
397.8	Network Equipment	9,689	26.26%		2,544		
398	Miscellaneous Equipment	51,562	1.27%		655		
	Total General Plant	$6,693,364			$215,359	$484,461	$440,912
303	Intangible Plant - General	$207,216	2.19%	3/	4,538		

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF DEPRECIATION EXPENSE - SETTLEMENT RATES
GAS UTILITY - NORTH DAKOTA
PROJECTED 2003

Acct. No.	Account	2003 Average Balance	Settlement Depreciation Rate		Annual Depreciation	To Clearing Accounts	Clearing to Expense 4
	Common Plant						
389	Land	$191,572					
390	Structures and Improvements	2,270,865	2.93%		66,536		
391.1	Furniture and Fixtures	465,980	4.95%		23,066		
391.2	Computer Equip.- Bull/AS400	10,590	1.52%	1/			
391.3	Computer Equip. - PC	724,856	23.29%		168,819		
391.5	Computer Equip. - Other	113,466	0.46%	1/			
392.1	Trans. Equip., Non-Unitized	33,295	-	2/			
392.2	Trans. Equip., Unitized	608,336	13.33%	2/		81,091	74,312
392.3	Aircraft	243,401	15.00%	2/		36,510	36,510
393	Stores Equipment	4,744	2.80%		133		
394.1	Tools, Shop & Gar. Equip.	43,006	6.11%		2,628		
394.3	Vehicle Maint. Equip.	13,926	-0.14%		(19)		
394.4	Vehicle Refueling Equip.	106,704	-1.09%		(1,163)		
396.2	Work Equipment Trailers	20,203	2.69%	2/		543	183
397.1	Radio Comm. Equip.-Fixed	106,748	4.99%		5,327		
397.2	Radio Comm. Equip.-Mobile	150,883	4.08%		6,156		
397.3	General Tele. Comm. Equip.	110,151	8.72%		9,605		
397.5	Supervisory & Tele. Equip.	9,333	0.35%		33		
397.8	Network Equipment	124,138	17.95%		22,283		
398	Miscellaneous Equipment	76,293	2.41%		1,839		
	Total Common Plant	$5,428,490			$305,243	$118,144	$111,005
303	Intangible Plant - Common	2,233,244	10.21%	3/	228,014		
386.3	Gas Plant Leased to Others	11,374	3.70%		421		
114.2	Acquisition Adjustment	97,266			2,819		
	Total Gas Plant in Service	$72,793,329			$2,561,524	$602,605	$551,917

Summary				
Distribution	$58,133,749		$1,805,551	
General	6,693,364		215,359	440,912
General Intangible	207,216		4,538	0
Common	5,428,490		305,243	111,005
Common Intangible	2,233,244		228,014	0
Acquisition Adj.	97,266		2,819	0
Total	$72,793,329		$2,561,524	$551,917

1/ Fully depreciated.
2/ Charged to a clearing account.
3/ Amortized. Rate reflects annual amortization/plant.
4/ % to clearing - Vehicles - 91.64%, work equipment -33.74% and others 100%.

APPROVED
DATE: 5-21-03
KME

MOTION

May 21, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission bill Montana-Dakota Utilities Co. for costs incurred to date in Case No. PU-399-02-183, Montana-Dakota Utilities Co., Natural Gas Rate Increase, Application.

149 **PU-399-02-183** Pages: 3

Utility Valuation Motion/Letter/Billing Statement
by Public Service Commission

05/21/2003 CC: Comm Legal PUD (3) Mike ALJ

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Leo M. Reinbold
Susan E. Wefald

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

May 21, 2003

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

RE: Case No. PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the May 21, 2003 Public Service Commission meeting for the expenses incurred to date in Case No. PU-399-02-183.

Under N.D.C.C. 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Administrative Staff Officer
701-328-2401

Enc.

Billing Statement

May 21, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

Expenses Incurred to Date:

Consulting Services	$12,631.18

Amount Due:

Montana-Dakota Utilities Co.	$12,631.18

Send Payment and a Copy of this Statement To:

Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

Public Service Commission
Receipt of Payment

Receipt# 5391

Received: 5/27/2003 Check# 979483 for $12,631.18

Subject: Utility Valuation

Docket # PU-399-02-183

Montana-Dakota Utilities Co., a Division of MDU Resources
400 N 4th Street
Bismarck ND 58501

148 PU-399-02-183 Pages: 1

Receipt# 5,391 $12,631.18

by Montana-Dakota Utilities Co., a Division of MDU Re

05/27/2003

Public Service Commission
Receipt of Payment

Receipt# 5373

Received: 5/15/2003 Check# 978610 for $2,685.03

Subject: Utility Valuation

Docket # PU-399-02-183

Montana-Dakota Utilities Co., a Division of MDU Resources
400 N 4th Street
Bismarck ND 58501

147 PU-399-02-183 Pages: 1

Receipt# 5,373 $2,685.03

by Montana-Dakota Utilities Co., a Division of MDU Re

05/15/2003

APPROVED

DATE: 5-7-03

KMF

MOTION

May 7, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission bill Montana-Dakota Utilities Co. for costs incurred to date in Case No. PU-399-02-183, Montana-Dakota Utilities Co., Natural Gas Rate Increase, Application.

146 PU-399-02-183 Pages: 3

Utility Valuation Motion/Letter/Billing Statement
by Public Service Commission

05/07/2003 CC: Comm Legal PUD (3) Mike ALJ

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Leo M. Reinbold
Susan E. Wefald

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

May 7, 2003

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

RE: Case No. PU-399-02-183
Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the May 7, 2003 Public Service Commission meeting for the expenses incurred to date in Case No. PU-399-02-183.

Under N.D.C.C. 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Administrative Staff Officer
701-328-2401

Enc.

Billing Statement

May 7, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

Expenses Incurred to Date:

Consulting Services	$2,368.82
Advertising Costs	316.21

Amount Due:

Montana-Dakota Utilities Co.	$2,685.03

Send Payment and a Copy of this Statement To:

Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

April 28, 2003

RECEIVED
APR 28 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505

Re: Depreciation Study
Case No. PU-399-02-183

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. herewith submits the original and seven (7) copies of the rebuttal testimony of Mr. Earl M. Robinson.

Please acknowledge receipt by stamping or initiating the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

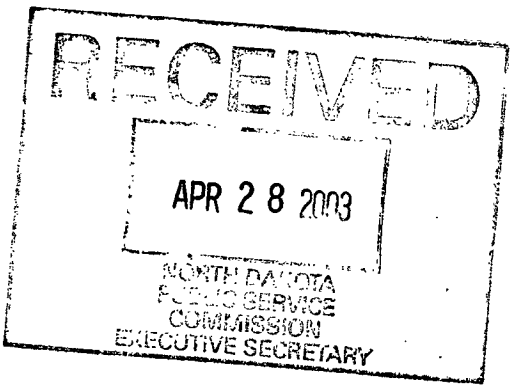
Sincerely,

Donald R. Ball

Donald R. Ball
Assistant Vice President –
Regulatory Affairs

Attachment
cc: D.W. Schulz
Charles King

145 PU-399-02-183 Pages: 1
Letter re filing of rebuttal testimony
by Montana-Dakota Utilities Co , a Division of MDU Re
04/28/2003 CC: Comm Legal PUD (3) Mike ALJ .



MONTANA –DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission
Case No. PU-399-02-183

REBUTTAL TESTIMONY
OF
EARL M. ROBINSON, CDP
PRESIDENT & CEO
AUS CONSULTANTS -
WEBER FICK & WILSON DIVISION

Concerning
Gas Depreciation and Common Plant Studies

144 **PU-399-02-183** Pages: 73
Rebuttal Testimony of Earl M. Robinson
by Montana-Dakota Utilities Co., a Division of MDU Re
04/28/2003 CC: Comm Legal PUD (3) Mike ALJ

REBUTTAL TESTIMONY OF EARL M. ROBINSON

Q. STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Earl M. Robinson. I am President & CEO of the Weber Fick & Wilson Division (WFW) of AUS Consultants - Utility Services. WFW is a public utility consulting firm specializing in the performance of various financial studies including depreciation, valuation, cost of service and other analysis for the utility industry and regulatory agencies. AUS Consultants provides a wide spectrum of consulting services through its various affiliated groups that include Utility Services, Valuation Services, ICR Survey Research, and Marketing Systems. WFW is located at 1000 North Front Street, Suite 200, Wormleysburg, Pennsylvania 1704

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I am a graduate of Harrisburg Area Community College with an Associate of Arts Degree in Accounting and have completed additional courses at University Center of Harrisburg. I have also successfully completed numerous programs related to service life and salvage estimation, forecasting, and evaluation sponsored by Depreciation Programs, Inc., as well as training programs presented by the Society of Depreciation Professionals. In addition, I have completed cost of service seminars sponsored by the American Water Works Association.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. I have been employed by WFW as a public utility consultant from 1971 to 1975 and 1977 to date. During these periods, my responsibilities have included the supervision of analyses and completion of studies related to depreciation, valuation, original cost, trended original cost, cost of service and bill analysis, as well as analyses of expenses, revenues, accounting adjustments for various municipal and investor-owned utilities. Studies prepared have required the review of company records, inspection of property, the preparation of property inventories and original costs, preparation and review of mortality studies, selection of proper service lives and life characteristics, analysis of salvage and analysis of the capital recovery impact of changing depreciation methods. Other areas of responsibility have included the preparation and selection of indices, development of rate base elements, development of data for cost of service studies and testing of consumption and revenue data in the preparation of bill analyses.

From 1975 to 1977, I was employed by Gannett, Fleming, Cordry & Carpenter, Inc. as a valuation analyst. My responsibilities included the classification, analysis and coordination of data in the development of depreciation rates for various companies including telephone, gas, water and electric utilities. During the years 1966 to 1971, I was a staff member of the Plant Accounting Department of United Telephone Company of

Pennsylvania (now Sprint-Eastern Group Headquarters). My responsibilities included the preparation of various plant accounting ledgers and unitization of property accounts, as well as special studies related to insurance and tax valuations. In summary, I have more than thirty (30) years experience in the public utility field.

As a member of the AGA Depreciation Committee (a predecessor to the current AGA Accounting Services Committee), I am a past Chairman of the Statistics, Bibliography, Court and Regulatory Sub-Committee. During my years of membership of the prior organization, as well as the present committee, I participated in many conferences that have incorporated research, analysis, and discussions of numerous depreciation issues and topics. In addition, as a member of the AGA Depreciation Committee, I co-authored a manual entitled *"An Introduction to Net Salvage of Public Utility Plant"* which is used as reference material in AGA/EEI training seminars.

Q. PLEASE STATE ANY ADDITIONAL DEPRECIATION QUALIFICATIONS.

A. I am a Certified Depreciation Professional. The certification is issued by the Society of Depreciation Professionals and is received upon successful completion of an extensive written examination covering all aspects of depreciation. I completed the examination during October 1996.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL SOCIETIES?

A. Yes, I am a member of the American Gas Association, the American Water Works Association, the Pennsylvania Gas Association, an associate member of the American Gas Association (AGA) Accounting Services Committee (past Chairman of the Statistics, Bibliography, Court and Regulatory Sub-Committee), and a member of the American Railway Engineering Association. I am also a founding member of the Society of Depreciation Professionals. As part of that organization, I held numerous positions including President.

Q. MR. ROBINSON, HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before numerous regulatory agencies concerning telephone, gas, water and electric utilities. I have presented testimony to the Alberta Utilities Energy and Utilities Board, Arizona Corporation Commission, the Connecticut Department of Public Utility Control, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Federal Energy Regulatory Commission, the Illinois Commerce Commission, the Massachusetts Department of Public Utilities, the New Hampshire Public Utilities Commission, the New Jersey Board of Public Utilities, the New Mexico Public Service Commission, the New York Public Service

Commission, the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the State of Rhode Island Public Utilities Commission, the Public Service Commission of South Carolina, the Virgin Islands Public Services Commission, the California State Board of Equalization and several Valuation Boards with the State of Florida. A list of those prior appearances is set forth in Appendix A of this testimony.

Q. HOW DID YOU FAMILIARIZE YOURSELF WITH THE COMPANY'S PROPERTY, WHICH IS THE SUBJECT OF YOUR ANALYSIS?

A. To obtain an overview and knowledge of the Company's facilities, I met with Company representatives to discuss its general scope of operations, which could have a bearing on the service lives of the Company's property. In conjunction with the management meetings, I performed a physical plant inspection of a representative portion of the Company's above-ground facilities. Likewise, the Company's financial management provided detailed information related to each of the Company's plant investment and net salvage databases. Accordingly, my study involved a detailed analysis of the historical accounting data obtained from the Company's continuing property records.

Q. WHAT WAS THE SOURCE OF THE DATA, WHICH YOU UTILIZED AS A BASIS FOR THE DEPRECIATION RATES YOU ARE RECOMMENDING PER YOUR STUDY?

A. All of the Company's historical data utilized in the course of performing the detailed service life and salvage study was obtained from the Company's books and records. The historical vintaged data (additions, retirements, adjustments, and balances) were obtained for each of the Company's depreciable property groups.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I have conducted the depreciation studies of the natural gas and common plant in service of Montana Dakota Utilities Co. (Montana-Dakota, or the "Company") as of December 31, 2001. The depreciation study reports are entitled Montana Dakota Utilities Co. Gas Division Depreciation Study as of December 31, 2001 which is identified as Exhibit No.-___ (EMR-1). The Common Plant study is entitled Montana Dakota Utilities Co. – Common Plant Depreciation Study as of December 31, 2001 and is identified as Exhibit No.-___ (EMR-2). Accordingly, I am providing rebuttal testimony relative to statements made and positions taken by Mr. Charles W. King who filed direct testimony on behalf of the Consumer Advocate Staff of the North Dakota Public Service Commission in this case.

Q. WHAT COMMENTS DO YOU HAVE RELATIVE TO MR. KING'S OPENING SUMMARIZATION OF HIS DEPRECIATION PROPOSAL (PAGE 3 OF HIS TESTIMONY)?

A. On page 3 of his testimony, Mr. King sets forth the impact of his depreciation proposal as it relates to the Company's current level of depreciation and as compared to the recommendations set forth in the Company's Gas Depreciation study. With regard to the Company's gas distribution plant (the primary operating component of the Company's overall investment) Mr. King is proposing approximately a 50% percent reduction in depreciation rates and expense from the current going level and more than a 40% reduction from the depreciation rates set forth in Company's filed Gas depreciation study. While Mr. King's depreciation recommendation relative to the General Plant component is generally similar in level to the present depreciation rates for that function, his proposal does not give recognition to the dramatic changes that have occurred with regard to those property groups. Lastly, Mr. King's depreciation proposal relative to the Company's Common Plant results in a 10% reduction in depreciation from the Company's current depreciation level and a nearly 30% reduction from the depreciation rates set forth in the Company filed Common Plant depreciation study. All of Mr. King's proposed depreciation deductions are unjustified and inappropriate, but his radical proposed reduction to the Company's Gas Distribution function

depreciation rate is particularly disconcerting. The depreciation rates set forth by Mr. King for the Company's distribution plant are clearly not reflective of the capital recovery requirements for this plant. Furthermore, Mr. King's recommendations are dramatically far removed from any normal depreciation level within the gas industry, and equally important, would no doubt result in financial harm to the Company's operations. That is, such a reduction in depreciation expense for the Company property will serve to reduce cash flow and potentially impact the Company's overall capital costs.

The bottom line of Mr. King's proposal is simply one of deferral, and then deferring some more, the true total cost of providing service to the Company's customers. Mr. King's selection of estimated service lives and his proposed use of the SFAS method (a discounted cash flow approach) to define the current period's appropriate share of the future retirement cost (cost of removal) are inappropriate. The method grossly understates the current apportionment of those total life costs. The use of Mr. King's proposed net salvage approach is akin to the sinking fund depreciation method that was used long ago by some regulatory agencies to calculate depreciation rates, but was discarded as not being appropriate to set just and reasonable depreciation rates.

Q. ON PAGE 5 LINES 24 & 25 OF HIS TESTIMONY MR. KING STATES THAT "THE ONLY PARAMETER THAT IS ABOSLUTELY REQUIRED (TO CALCULATE A DEPRECIATION RATE) IS AN ESTIMATE OF THE SERVICE LIFE....". DO YOU HAVE A RESPONDING COMMENT?

A. Yes, while in absolute terms of being able to mathematically calculate a depreciation rate Mr. King may be generally correct, however, he is incorrect in not recognizing the critical importance of net salvage. That is, it is "equally imperative" that the calculation include recognition of the net salvage relative to the plant being recovered. It is not just an after thought of "oh, maybe we should consider net salvage"—it is a key component in the development of the depreciation.

Q. ON PAGE 8 OF HIS TESTIMONY, MR. KING STATES THAT THERE WERE PROBLEMS WITH THE HISTORICAL DATA. DO YOU HAVE AN EXPLANATION RELATIVE TO THIS ISSUE?

A. On page 8, Lines 14 to 19 Mr. King discusses issues he has with the basic historical data. Unfortunately, in the assembling the basic historical data the Company was unable to retrieve historical information relative to additions and retirements prior to January 1, 1948. Notwithstanding, the fact that the account balance of the Company's plant in service as of January 1, 1948 was only approximately 6% of the current balance, the life analysis process uses information relative to additions and retirements

available since the inception of the property groups. While this earlier data does not influence the results to any significant degree, an attempt was made to recreate the information as best as possible through the inclusion of estimates. To estimate the additions and retirement activity for the years 1946 to 1948 the amounts were estimated as being equal to the 1949 amounts. With regard to the War years 1941 through 1945, which Mr. King discussed in his testimony, no amounts were included for either additions or retirements. The decision not to include activity for the war years was based upon experience from reviewing numerous other utility reports during those time periods. Given the limitation of the available (and rationing of) materials during the war years little activity occurred within most utilities. For years prior to the war year's gross additions were generally reduced by 2.5 percent for each prior year's activity to give recognition for plant growth over time. The level of annual retirements was based upon a ratio of each year's gross additions. Again while the level of plant activity is quite modest as compared to current plant and produces only a limited impact on any study results, an attempt was made to estimate values for those years as best as possible.

Q. ON PAGES 12, LINES 24 TO 29 AND PAGES 13 TO 16 OF HIS TESTIMONY, MR. KING DISCUSSES HIS RECOMMENDATIONS OF AVERAGE SERVICE LIFE PARAMETERS FOR A VARIETY OF THE

COMPANY'S PLANT ACCOUNTS. ALSO MR. KING STATES THAT YOUR PREPARED SPR ANALYSIS (RESULTS) DO NOT SUPPORT THE SERVICE LIFE PARAMETER RECOMMENDATIONS SET FORTH IN THE COMPANY'S DEPRECIATION STUDY. WHAT IS YOUR RESPONSE?

A. First. I will respond with regard to Mr. King's criticism that my SPR analysis results do not support the "average service life parameter" recommendations contained in the Company's Gas Depreciation Study Exhibit No.-___ (EMR-1). In response to Mr. King's statement, a discussion of the basic concepts and underlying reasons for historical life analysis is required, and then, secondly, the general assumptions and range of considerations that enter into the estimation of the proposed average service life parameters is also required. The historical data and related life analysis is a basic depreciation study tool which is assembled to enable the depreciation professional to determine (estimate) forward looking service life and salvage parameters used in completing a comprehensive depreciation study. That is, the data base is a source from which to prepare historical analysis, make assessments and judgments concerning the life and salvage factors being achieved. **The historical life analysis procedure and indicated service life parameter results is a tool not an end in and by itself**. In the process of assessing the service life analysis results, one must consider not only the results of the historical analysis, but also must give recognition to the general life characteristics of utility

property when selecting the survival characteristic (i.e., the Iowa Curve that goes along with the average service life.) Simply said, utility property is generally placed into service with the expectation that it will remain in service for some time before it is removed from service. That is, there is not a general expectation that significant levels of property retirements will occur shortly after the property is placed into service. In that regard, in estimating survival characteristics (Iowa Curves) for the various plant categories, a somewhat greater focus is placed on more Right Mode Iowa Curves (R Curves as opposed to O and L Curves); as well as higher subscript Curves, 2.5 and 3 curves as opposed to 1 and 2 Curves). In his life parameter selections, Mr. King has generally focused on the more left mode and lower subscript Curves simply because they met "some of his other criteria and conceivably indicated a better arithmetic fit of the available historical data. The impact of his selection process is to estimate average service lives that are, 1) longer than appropriate and, 2) do not generally represent the characteristic of the property being studied. Standard service life depreciation analysis processes were utilized along with the Company's developed depreciation data base compiled through December 31, 2001 to develop property life indications. Likewise, the net salvage data base was used as a basis to identify historical experience and trends and to determine each property group's recommended net salvage factors. This process is used as a benchmark, together with professional

analysis and consideration, to estimate future lives and salvage factors over which to recover the Company's un-depreciated fixed capital investments. It is not a process of simple arithmetic calculations and accepting whatever is generated from the "Computer Analysis" to estimate the future parameters, but one of clear and deliberate consideration of all factors impacting the Company's property.

I will now respond to various specific account criticisms made by Mr. King.

Account 375 - Distribution Meas. & Reg. Structures and Improvements. This class of property contains investments relative to structures which tend to be placed into service followed by somewhat limited subsequent activity. Mr. King's selection of an S1 curve implies that greater levels of young aged retirements (mortality) than the proposed R2.5 curve contained in the Company's depreciation study Exhibit No.-___ (EMR-1). Even a somewhat limited change to a more right mode or higher subscript curve would have altered his conclusion. For example, even if Mr. King had selected an S2 or S3 curve, which demonstrates fewer early aged retirements (rather than simply the historical arithmetic best fit curve of an Iowa S1 Curve) his resulting average remaining life recommendation would have been shorter (which translates into a higher depreciation rate) than my proposed remaining life using the R2.5 Iowa Curve.

Account 376 – Mains. While Mr. King has selected an "R" mode Iowa curve for this property group, he has again selected a relatively low

subscript curve, an Iowa R1.5 Curve as opposed to an Iowa R3 Curve recommended per the Company's Gas depreciation study Exhibit No.-___ (EMR-1). Conversely, the use of the estimated R3 Curve, within the Company's Depreciation Study, recognizes that a greater frequency of retirements will occur later in life as opposed to earlier in life. These estimated later in average life retirements is generally consistent with that anticipated by operating personnel for gas mains throughout the utility industry. Using the Iowa R3 curve for Account 376-Mains and Mr. King's own analysis per CWK-2 identifies that the indicated average service life of the Company's Main's investment should be 44.7 years (which is consistent with the life proposed by the Company's depreciation study). Also following Mr. King's own general criteria for estimating the applicability of a service parameter within the life analysis process, the Retirement Experience Index for an Iowa 44.7-R3 Curve is at 100 (higher is better) as opposed to the 57.6-R1.5 Curve which has a Retirement Experience Index of 87.5. Furthermore, as a general check on the reasonableness of the estimated Iowa 45-R3 service life parameters estimated per the Company's depreciation study report Exhibit No.-___ (EMR-1), the AGA depreciation survey indicates that nearly one-third of the reporting companies are utilizing a service life in the range of 45-52 years. However, in reviewing such statistics one must recognize that segments of this industry data are being influenced by sizeable investments related to Cast Iron Main dating

back to the 1800's which has routinely experienced a substantially longer average service life due to operating at far lower operating pressures, etc. The Company does not have Cast Iron Mains. Absent that service life information relative to cast iron main property, the overall average of the industry service lives is most likely years shorter.

Finally, Mr. King states that he is recommending the use of a Whole Life based depreciation rate as opposed to a Remaining Life based depreciation rate for this asset categories. This approach of switching to a different depreciation technique for this account and one other account is apparently an effort to offset some of the impact of his inappropriately proposed depreciation parameters and procedures which produce results that even Mr. King recognizes as totally irrational.

Account 378 – Measuring & Regulating Station Equipment. Again, Mr. King has selected an average service life parameter (an SC Curve which is a constant retirement percent dispersion) indicating that from day one after the property group investment is placed in to service the property group will experience continuous and ongoing retirements. Such a service life parameter is not anticipated and/or realistic for this class of property. Conversely, the Company's filed Gas depreciation study Exhibit No.-___ (EMR-1) recommends an Iowa R1 Curve for this property category. While the Iowa R1 curve recognizes that various levels of retirements will occur throughout the property's life, the anticipated retirement levels are not

nearly as accelerated as that indicated under Mr. King's recommendation. Furthermore, in reviewing Mr. King's Exhibit CWK-2 it is further noted that the Company recommended Iowa R1 curve has a superior Retirement Experience Index (Mr. King's selected criteria) of 99.5 versus a Retirement Experience Index of 82.2 for Mr. King's selected SC Curve.

Account 379 – Measuring & Regulating Station Equipment – City Gate. For this account Mr. King states that he picked the best SPR result with a Retirement Experience Index of greater that 75. His statement is incorrect; the Retirement Experience index is only 67.36 as shown by his Exhibit CWK-3. The important factor however is that he again selected an Iowa Curve (an S1) that experiences higher levels of retirements earlier in life than the Iowa R2.5 Curve incorporated into the Company's study for this property group. In general City Gate stations tend to be constructed to service a selected community and/or service territory. They are typical designed for the larger area as compared to a district regulator station and therefore tend to be less prone to changes earlier in life. Conversely, district regulator stations (Account 378) are more influenced by changes of demand within a given neighborhood and therefore would likely experience a somewhat greater level of retirements early in life (and thus would demonstrate a lower subscript curve). Again using Mr. King's own measurement criteria the Iowa 33.2-R2.5 (from Mr. King's Exhibit CWK-3) produces a Retirement Experience Index of 93.96 (higher is better) as

opposed to Mr. King's recommended curve of an Iowa S1 curve which produces a Retirement Experience Index of only 67.4.

Account 380 – Services. Mr. King has recommended a service life for the Company's Services account that is inconsistent with the general range of data he reviewed. As with essentially all previous accounts studied, his primary stated measurement criteria is that the recommended service life parameters historically generated a Retirement Experience of greater than 75. In addition he has referenced that a life in the range of 60 to 80 years might be justified by the study data, even without giving consideration to the survivor life characteristics indicated by those life indications (extremely left modal Curves being mostly O mode curves and a low subscript (R1) curve). Furthermore, Mr. King quotes that the maximum life used by any AGA reporting Company is 63 years and that the average service life reported by the industry for Services is 40 years. All this data referenced by Mr. King better supports the Company's proposed service life of 40 years (per Exhibit No.-___ (EMR-1)) as opposed to the extremely long and irrational life of 55 years recommended by Mr. King. Also, the Iowa R2.5 recommended per the Company's Gas depreciation study produces a Retirement Experience Index (Mr. King's preferred measurement) of 100 versus Mr. King's recommended R1 Curve which produces a Retirement Experience Index of 83.9.

As with Account 376 – Mains Mr. King states that he is recommending the

use of a Whole Life based depreciation rate as opposed to a Remaining Life based depreciation rate. Again, this approach of switching to a different depreciation technique for these accounts is apparently an effort to offset some of the impact of his inappropriately proposed depreciation parameters and procedures which produce results that even Mr. King recognizes as totally irrational.

Account 381 – Meters. Mr. King's schedule on Page 15 of his testimony indicates that he recommended an Iowa R1.5 curve for this property group, however, his text on Page 14 of his testimony and his Ehibit CWK-1 Schedule 2 identifies that an Iowa R2.5 Curve was utilized as the applicable depreciation parameters. The Iowa R2.5 curve is the same as recommended by the Company's Gas depreciation report.

Account 383 – Service Regulators. This property investment is related to house regulators that are installed on the Customer premise to reduce the pressure from the distribution level to the lower pressure that is utilized by the customer's gas appliances, etc. This category of property experiences only minimal levels of early retirements given that the drivers for retirement tend to be generally physical in nature and/or could be the product of a pressure change with district service area. Accordingly, there is absolutely no justification for estimating an Iowa R1 Curve as the applicable service life parameter for this asset category. Reviewing Mr. King's curve fitting analysis (Exhibit CWK-2) for this account identifies that the Iowa R3 Curve

recommended per the Company's Gas depreciation study produces an indicated average service life of 32.4 (which is less that the 35 years recommended per the Company study report). Likewise the R3 Curve produces a Retirement Experience Index of 100 (higher is better) as opposed to Mr. King's recommended R1 Curve which has a Retirement Experience Index of 80 and an average service life of 38.7 years. Mr. King proposed a 40 year life for the account.

Account 385 – Industrial Measuring & Regulating Station Equipment.

Counter to Mr. King's statement that he is not surprised that Service Regulators and Industrial M&R Equipment would have the same life, these two categories of property are dramatically different classes of assets. The service regulator is a very small unit used for providing relatively small volumes of gas to residential and/or commercial customers. Conversely, Industrial Measuring & Regulating Station Equipment is typically a relatively larger regulator set used to provide large volumes of gas to industrial customers. These Industrial M & R facilities are more akin to District Regulator Stations but more susceptible to life limitations do to changing individual business operations. While the Company's Gas depreciation study recommended relatively similar depreciation parameters for Service Regulators and Industrial Measuring & Regulating Station Equipment it is not for the same reason as indicated by Mr. King. Even according to Mr. King's analysis the Iowa R2 Curve recommended by the Company's Gas

depreciation report produces a Retirement Experience Index of 95.8 while Mr. King's recommended R1 Curve produces a Retirement Experience Index of 78.4. Likewise Mr. King's R1 curve indicates greater levels of retirements earlier in life than does the Company's study recommendation of an R2 Curve.

Account 386 – Miscellaneous Equipment. As Mr. King stated, a larger portion of this property group's investment is related to CNG Refueling Station equipment. Due to the lack of historical retirements, the historical data does not produce applicable service life indications. This class of plant is an evolving technology which relies on various levels of cascading equipment that is upgraded over time. Also this is somewhat of an unproven product with regard to whether there is real long term viability for this asset class. Lastly the Investment in the class is relatively modest; accordingly, a 15 year life with an R3 Curve was deemed the most appropriate service life parameters for this asset class.

Account 387.10 – Cathodic Protection. Cathodic Protection is a technology driven asset group that does experience various levels of somewhat gradual and earlier in life retirements than represented by the Iowa L4 Curve proposed by Mr. King. Accordingly, the R1.5 Curve as recommended by the Company Gas depreciation study Exhibit No.-___ (EMR-1) is deemed as a superior life recommendation as opposed to Mr. King's proposed L4 Curve.

Q. MR. KING, ON PAGE 16, OF HIS TESTIMONY DISCUSSES YOUR DISAGGREGATION OF SELECTED ACCOUNTS. WHY DID YOU DISAGGREGATE THE INVESTMENTS IN VARIOUS ACCOUNTS?

A. In completing depreciation studies, it has been my practice, as well as the practice of various other depreciation professionals, to segment various larger plant accounts into more homogenous types of property groups. It is noted that the Company's investment in Account 376 - Mains comprises more than 45 percent of the Company's depreciable plant while Account 380 – Services comprises more than 18 percent of the depreciable plant. The segmentation of these assets and the calculation of individual sub-account depreciation rates provides the opportunity to look at separate types of property individually and then subsequently composite those rates together into a total account depreciation rate. It is not necessary that the Company accrue depreciation on the separate categories only that the depreciation professional consider the possible/probable differences between the facilities when developing depreciation rates. Conversely, relative to Mr. King's reference to Account 387, that property group was not disaggregated in performing the depreciation study. The Company maintains investment information in this manner on it books and records, therefore a depreciation rate was developed for each property category.

Q. ON PAGE 18 LINES 13 TO 19 OF HIS TESTIMONY MR KING DISCUSSES THE DATA THAT HE RECEIVED RELATIVE TO ACCOUNT 391 AS WELL AS HIS ANALYSIS AND RECOMMENDATIONS FOR THIS PROPERTY CATEGORY. WHAT COMMENTS DO YOU HAVE IN THIS REGARD?

A. Mr. King states that he included computers with office furniture into a composite analysis because he did not have the separated data. Mr. King was provided all the detail in electronic form in response to Staff DR1.1. In fact, the combined Account 391 data "was not" provided inasmuch as the Company only maintains the information on an individual sub-account basis. The only way that Mr. King could have obtained the total combined Account data would have been to physically add the sub-account related data together. Counter to Mr. King's rebuttal testimony concerning his statement that "he is not persuaded that the separation results in a more accurate picture", real life facts demonstrate a far different picture. The life of office furniture in no way has any relationship to the life expectancy of computer (PC) equipment. Mr. King's estimated life of 17 years for the overall account which is comprised of nearly 60 percent PC related equipment is totally unrealistic. In fact it is very routine for company's to experience 15 years as an average service life for non-computer related furniture and office equipment. Applying a 17 year life to Account 391.3 - PC Computer related equipment investment is another clear example

where Mr. King is proposing to defer recovery to future customers. With the ongoing radical and dramatic changes to PC and related software (which drives much of the equipment replacement) there is a never ending revolving door of PC equipment. The 15 year amortization period for Office Furniture & Equipment and the Iowa 5-R2 service life parameter recommended by the Company's Gas depreciation study report are justified, reasonable, and extremely well supported by extensive experience through the utility industry.

For example, of the various Companies reporting within the AGA/EEI depreciation statistics the mean average service life relative to Furniture and Equipment for 98 Gas Companies is 14 years while the median service life is 13 years. Similarly for 52 entities with Common Plant the reported mean average service life for Furniture and Equipment is 14 years while the median service life is 11 years, and for 168 electric reporting companies the mean average service life is 14 years while the median service life is 12 years. Within the above referenced reporting groups, for the single largest group, 31 of 98 reporting Gas companies, the average service life fell in the range of 2 to 8 years. By comparison, for 26 of 52 Common Plant reporting, the average service life was in the range of 5 to 10 years. Lastly, for 62 of 168 reporting electric companies, the average service life was in the range of 5 to 10 years. This information recognizes that the useful life of Furniture and Equipment is being significantly influenced by a short life

for Computer Equipment. Given that the AGA statistics report does not specifically separate depreciation lives between office furniture and equipment and PC Computer equipment, specific listings of the average service lives for PC's is not available from this source. Nevertheless there is extensive anecdotal evidence concerning the rapid changes and limited life of PC Equipment, however, the actual empirical evidence is somewhat more limited.

With regard to specific empirical evidence related to the average service of Computer Equipment, based upon the available actuarial data for the Company's Common Plant investments, a historical life analysis produced an average service life indication of 6 years for PC Equipment. Likewise, similar studies performed on Computer Equipment for several other entities including California-American Water, Illinois-American Water, and Northern Indiana Public Service produced life indications for Computer PC and Peripheral Equipment in the range of 5-8 years as shown on the accompanying data and curve plots (Exhibit No.-___ (EMR-3)). A curve plot for Montana-Dakota is also included in the exhibit. This information demonstrates that historically, the life being achieved for this asset class(PC's & Peripheral Equipment), is substantially shorter than that indicated by Mr. King. Furthermore, it is highly likely that sizable portions of the PC equipment remaining on the various Company's books and records is subject to increasing levels of obsolescence and is awaiting replacement

in the near term.

Q. ON PAGE 18 AND 19 OF HIS TESTIMONY MR. KING DISCUSSES VARIOUS LIVES RELATIVE TO AMORTIZATION PERIODS WHICH THE COMPANY HAS REQUESTED FOR SELECTED GENERAL PLANT ACCOUNTS. WHAT COMMENTS DO YOU HAVE IN THIS REGARD?

A. Mr. King states that he has performed life analysis on various of these accounts and/or retained the current life for others, namely 393, 394.1,394.2 394.3, 394.5, 397, and 397. The real issue is simply that the items in these accounts tend to be numerous and minor in nature which makes detailed record keeping administratively burdensome. Accordingly, this is the specific reason for the Company requesting to amortize these limited asset investments over a pre determined useful life. The proposed useful life was the product of the available historical data from Company as well as industry data along with input from Company management concerning the likely useful life of such property classes. To base the estimated amortization periods simply on the existing depreciation period and/or the life indication generated from questionable historical data alone is totally inappropriate. Accordingly, the amortiziation periods set forth on Table 2 (and as contained in the following list) of the Company's Gas depreciation report (Exhibit No.-___(EMR-1)) are the appropriate lives to use.

Acct. No.	Account Description	Amortiz. Period (Yrs)
391.10	Office Furniture & Equipment	15
393	Stores Equipment	35
394.10	Tools, Shop & Garage Eq. (Non-Unit)	18
394.20	Tools, Shop & Garage Eq. (Unitized)	18
394.30	Vehicle Maintenance Equipment	20
394.40	Vehicle Refueling Equipment	15
395	Laboratory Equipment	20
397.10	Radio Comm. Equip (Fixed)	15
397.20	Radio Comm. Equip (Mobile)	15
397.30	General Tel. Comm. Equip.	10
397.50	Supervisory & Telemetering Equip.	10
397.60	SCADA Equipment	8
397.80	Network Equipment	5
398	Miscellaneous Equipment	20

Q WHAT COMMENT DO YOU HAVE REGARDING MR. KING'S ESTIMATED AMORTIZATION PERIOD'S FOR COMMON PLANT ACCOUNTS AS DISCUSSED ON PAGE 19, LINES 29-31 AND PAGE 20 LINES 1-12 AND AS INCLUDED IN HIS EXHIBIT CWK-1 SCHEDULE 4?

A. As with his recommendation concerning the amortization of the Company

Gas Plant General Accounts the real issue for Common Plant is also simply that the items in these accounts tend to be numerous and minor in nature which makes detailed record keeping administratively burdensome. Accordingly, this is the specific reason for the Company requesting to amortize this limited asset investments over a pre determined useful life. The proposed useful life was the product of the available historical data from Company as well as industry data along with input from Company management concerning the likely useful life of such property classes. To base the estimated amortization periods simply on the existing depreciation period and/or the life indication generated from questionable historical data alone is total inappropriate. Accordingly, the amortization periods set forth on Table 2 (and as contained in the following list) of the Company's Common Plant depreciation report (Exhibit No.-___(EMR-2)) are the appropriate lives to use.

Acct. No.	Account Description	Amortiz. Period (Yrs)
391.10	Office Furniture & Equipment	15
393	Stores Equipment	30
394.10	Tools, Shop & Garage Eq. (Non-Unit)	18
394.30	Vehicle Maintenance Equipment	18
394.40	Vehicle Refueling Equipment	15
397.10	Radio Comm. Equip (Fixed)	15
397.20	Radio Comm. Equip (Mobile)	15

397.30	General Tel. Comm. Equip.	10
397.50	Supervisory & Telemetering Equip.	15
397.80	Network Equipment	5
398	Miscellaneous Equipment	20

Q. DO YOU HAVE A COMMENT CONCERING MR. KING'S ESTIMATED AVERAGE SERVICE LIFE FOR THE COMPANY'S COMMON PLANT PC EQUIPMENT?

A. Mr. King is recommending a 15 year average service life relative to the Company's Common Plant Account 391.3 PC Computer Equipment. Similar to Mr. King's position for Gas-General Plant, to even consider applying a 15 year life to PC Computer related equipment investment is totally beyond belief. With the ongoing radical and dramatic changes to PC and related software (which drives much of the equipment replacement) there is a never ending revolving door of PC equipment. The Iowa 5-R3 service life parameter recommended by the Company's Common Plant depreciation study report is justified, reasonable, and extremely well supported by extensive experience through the utility industry as I previously discussed for gas general plant. I would again refer you to Exhibit No.-___(EMR-3).

Q. LIKEWISE, MR. KING IS RECOMMENDING THE USE OF AN IOWA 13-L1 LIFE AND CURVE FOR THE COMPANY'S COMMON PLANT ACOUNT 392.2 –CARS AND TRUCKS INVESTMENT. WHAT COMMENT DO YOU

HAVE CONCERING THIS RECOMMENDATION?

A. Suggesting that, on average, the Company's Cars and Trucks would ever last 13 years is just not realistic. Such a recommendation is just simply wrong. Secondly, Cars and Trucks are routinely placed into service and continue to be utilized for a typical life period. While there may be some limited circumstances where vehicles are involved in accidents, etc and taken out of service early in their service period that is far from the norm. Mr. King's estimate of an L1 curve along with a 13 year average service life suggests not only do the Company vehicles last, on average, an extremely long period of years, but also that relatively sizeable portions of the property is taken out of service over the entire service period from zero age to maximum life. This recommended service life parameter is simply illogical. Mr. King's recommendation is even more irrational due to the fact that the Company has been purchasing increased amounts of (previously owned) "Program Vehicles." These vehicles, while new to the Company, already have been used for a period of time. Conversely, the Iowa 7-R3 Life and Curve recommended via the Company's Common Plant depreciation study for the Company's Account 392.2 – Cars and Trucks is supported, rational, and reasonable.

Q. ON PAGE 21 OF HIS TESTIMONY MR. KING SUMMARIZES AND HIGHLIGHTS THE NEGATIVE SALVAGE FACTORS INCLUDED IN THE COMPANY'S DEPRECIATION STUDIES. WERE THERE POSITIVE NET SALVAGE FACTORS ESTIMATED FOR VARIOUS OTHER ACCOUNTS?

A. Yes, while Mr. King focuses only on the negative net salvage factors there were, likewise, positive net salvage estimated for various accounts. The net salvage summaries, and analysis included within the Company's depreciation studies were handled consistently for all the property groups studied.

Q. WITH REGARD TO THE CURRENT WORK EFFORT AND RELATED COSTS ATTRIBUTABLE TO THE COST INCURRED IN RETRING PLANT, IS IT ANTICIPATED THAT IN FUTURE YEARS, THE REQUIREMENT UPON THE COMPANY WILL BECOME MORE OR LESS STRINGENT?

A. As with all operations and related regulations, it can only be anticipated that with the passage of time such government regulations and other requirements upon the Company will be more stringent thereby increasing effort and resulting cost incurred in conjunction with retirements. That is, not only will future costs likely increase as a result of future labor cost increases, etc but the level of requirements and related costs are also anticipated to increase.

Q. ON PAGES 21-23 OF HIS TESTIMONY MR. KING DISCUSSES THE APPROACH THAT WAS USED TO ANALYZE NET SALVAGE WITHIN THE COMPANY'S DEPRECIAITON STUDY. IS HIS DISCUSSION CORRECT?

A. Mr. King's initial discussion about how the calculations were prepared are

essentially correct, however, once he begins his discussion of how the data analysis results were interpreted and incorporated into the recommended depreciation rates, he is incorrect.

First, as previously noted in this testimony during discussions related to average service life analysis, " **the net salvage data base was used as a basis to identify historical experience and trends and to determine each property group's recommended net salvage factors. This process is used as a benchmark, together with professional analysis and consideration, to estimate future lives and salvage factors over which to recover the Company's depreciated fixed capital investments. It is not a process of simple arithmetic calculations and accepting whatever is generated from the "Computer Analysis" to estimate the future parameters, but one of clear and deliberate consideration of all factors impacting the Company's property."**

For example on Page 23 Lines 1 to 7 and later on Page 24, Mr. King discusses as some length the fact that the linear trend analysis produces negative gross salvage percent. He expounds in great volumes about the absurdity of the calculation of negative gross salvage percents. I agree wholeheartedly that there is absolutely no justification for incorporating the **negative "gross salvage percents"** into the recommended annual depreciation rates. In fact, no such data was incorporated in the annual depreciation rates recommended per the Company's depreciation studies.

However, as previously indicated in the discussion above, the same consistent calculations were utilized for all of the accounts studies. The bottom line is that the linear analysis of the gross salvage trend shows that there is a likelihood that such accounts that trend to "negative gross salvage percents" will experience little or no gross salvage irrespective of the fact that on an overall historical basis those accounts demonstrated (in some circumstances) relatively significant levels of positive salvage. Again the information is calculated consistently for all accounts, and is available for professional analysis and interpretation.

Q. ON PAGE 23, LINES 28-31 AND PAGE 25 LINES 1-13 OF HIS TESTIMONY MR. KING LAMENTS THE INCORPORATION OF THE COST OF REMOVAL ADJUSTMENTS INTO THE COMPANY'S FUTURE COST OF REMOVAL ESTIMATES. WHAT IS YOUR RESPONSE?

A. First, just because Mr. King has not seen such a presentation does not make the process invalid. In fact the very textbook that Mr. King references in his testimony, "The NARUC Public Utility Depreciation Practices", references age sensitivity in salvage and cost of removal in its discussion on net salvage on pages 158-161. Furthermore on page 288 of that same textbook, listed as a bibliography is an AGA/EEI paper by a well recognized expert Mr. John Ferguson on the subject of "Influence of Aged Net Salvage on Depreciation Rates." Furthermore there is a 1989 AGA/EEI treatise

entitled "An Introduction to Net Salvage of Public Utility Plant" which discusses the subject of age sensitivity of gross salvage and cost of removal.

Q. DOES THE INCLUSION OF THE AJUSTMENT TO THE COST OF REMOVAL PERCENT RESULT IN DOUBLE COUNTING INFLATION AS SUGGESTED BY MR. KING ON PAGE 25, LINES 1 TO 17?

A. Absolutely not. The whole process is quite easy to understand. First, one must remember that for each property group an average service life has been estimated. That average service life of say 30 years indicates that the entire current investment within the property account, on average, will be retired at that age to attain an average service life of 30 years. Secondly, historical retirements have occurred to date. Those retirements have been analyzed to both identify the average retirement age to date (lets assume 10 years) at which the retirements have occurred, and in addition what percent of the original costs of retirements was experienced by the Company for Cost of Removal. That is, relative to the cost of removal percent if the Company had historically booked retirements with an original cost of $1,000 and it incurred $500 of cost of removal to retire the asset it is said that the cost of removal percent is 50% ($500/$1,000) (that also being 50% negative net salvage, if there was no corresponding gross salvage in conjunction with the retirement). Lets also estimate that the overall long run

inflation rate is 2.75%.

Next, now that it is known that the retirements that generated the 50% cost of removal occurred at 10 Years, the average service life of the property within the asset group is 30 years, and that the long run inflation rate is 2.75%, one can readily estimate the anticipated future cost of removal percent at the end of the property's average life. That is, it can be readily extrapolated that the average retirement age will need to increase, on average, another 20 years (30 Yrs ASL-10 years average retirement age) before the property is retired, on average, at an age of 30 years.

In simple, non-compounded terms a 2.75% cost increase per year for 20 additional years is 55%. For this example, the original 50% cost of removal plus the additional 55% totals to 105% cost of removal.

As one can easily see, counter to Mr. King's testimony, there is no double counting of inflation. The initially experienced 50% cost of removal is attributable to the actual cost of removal incurred through the 10 year average age, while the additional 55% cost of removal is attributable to the increased cost of removal during the subsequent additional 20 year period (required for the property to be retired, on average, at average service life).

Q. ON PAGE 26 OF HIS TESTIMONY, MR. KING STATES THAT EMPIRICALLY, THERE IS NOT A SHRED OF EVIDENCE THAT OVER TIME POSITIVE GROSS SALVAGE RATIOS DECLINE AND NEGATIVE

REMOVAL COST RATIOS INCREASE. WHAT IS YOUR REACTION TO THIS STATEMENT?

A. There is an unlimited number of examples where the age sensitivity of gross salvage and cost of removal can be illustrated. In its simplest form I doubt that anyone would be willing to pay me as much for a similar model of a 5 year old used computer as a 2 month old used computer. Similarly if I had a 6 year old used van, I wonder if anyone would pay me equally as much for that vehicle as for a 2 month old van of the same type.

The same concept can be identified for cost of removal. As time passes all employees seek and desire to have a higher salary, plus other costs also increase. Hence as time passes the level of cost to complete a similar task will increase. Working from the assumption that we are discussing removing the same item that has the same original cost at different points in time (at age 5 as opposed to age 1) the percent level of cost of removal clearly will increase.

In his discussion on page 26 lines 8 to 13, Mr. King argues that the cost of removal percent, as shown on his Exhibit CWK-6, supports his statement that the cost of removal does not increase with age. Mr. King does not understand. The reason that age sensitivity is not discernable within the summary salvage data provided in Section 8 of the Company's Gas & Common Plant depreciation studies is the fact that the retirements that

generated the net salvage is a mixture of various vintages of property. Furthermore, the average age of retirements, in aggregate, that have been occurring over time have not changed that significantly. If one were to disaggregate such activity into separate vintage data it is clearly obvious that both gross salvage and cost of removal would reflect levels of age sensitivity.

Furthermore, counter to Mr. King's discussion at the bottom of Page 26, Lines 24 to 31 where he argues that Company annual retirements, on average and in aggregate, will not trend towards average life, this is simply a non issue. It is not about whether in any one year, on average and in aggregate, the retirements reach average service life. The bottom line is that those individual retirements will have to occur at old ages if the average service life is to occur. If, for example, Mr. King is arguing that the average age of retirements will, in total, occur at younger ages, then the estimated average service life for each of the property groups is far too long.

Q. AT THE BOTTOM OF PAGE 27 OF HIS TESTIMONY MR KING SUMMARIZES WHAT HE INDICATES ARE HIS ESTIMATED NEGATIVE NET SALVAGE RATES BASED UPON HIS ANALYSIS AND WHAT HE REFERS TO AS THE "CONVENTIONAL PROCEDURE". WHAT ARE YOUR COMMENTS?

A. In developing his negative net salvage on what he calls a conventional

procedure for 3 of the 4 accounts listed he simply bases his estimate on the average of 33 years historical experience irrespective of the fact that many of the earlier years experience significantly lower levels of negative net salvage while more recent years experience higher levels of negative net salvage.

One must recognize that with regard to estimating future net salvage for the average remaining life depreciation rate, it is not about what has occurred in the past, but what will occur in future years. That is, the development of the average remaining life depreciation rate is based upon recovering the un-recovered original cost adjusted for the estimated future positive or negative net salvage over the average remaining life.

Q. ON PAGES 28 AND 29 OF HIS TESTIMONY, MR. KING ESSENTIALLY DISCUSSES ANALYZING COST OF REMOVAL ON A CONSTANT DOLLAR BASIS, THAT IS, ELIMINATING ANY INCREASES IN COST OVER TIME CAUSED BY INFLATIONARY PRESSURES. IS HIS CALCULATION CONCEPT RATIONAL, AND/OR IN ANY WAY ACCEPTED OR SUPPORTED BY DEPRCIATION PROFESSIONALS, ACADEMIA, OR REGULATORS?

A. Absolutely not. We do not live in a constant dollar world and it is extremely unlikely that we ever will. It will essentially always cost more to remove facilities from service 30 or 40 years hence than it would today because,

among other reasons, labor rates increase inasmuch as all employees seek to obtain a higher level of pay with the passage of time. Also, by the very nature of the property, retirement cost (cost of removal) must occur at the end of life. Therefore the cost of removal, which is an end of life cost, must be added to the initial installed cost to define the true total life cost of property which must be recovered ratably over the life of the asset from the customers receiving service from the property's use. The combination of the initial cost and end of life cost is no different than having constructed an initial facility (say a structure) during 1950; then adding to that structure during 1960, 1970, and 1980 and finally retiring the facility in 1990. The sum of all those costs along with any cost of removal must be recovered ratably over the life of the property.

The method utilized in the development of the Company current estimates of negative net salvage and resulting depreciation rates is consistent with standard practices and procedures within the depreciation profession, their development is consistent with basic accounting matching principles and follow the long time and well founded practices of ratemaking principles. Conversely, Mr. King is advancing a new theory of cost recovery that clearly results in inappropriate deferral of cost recovery.

Q. ON PAGE 30, LINES 11 TO 21, MR. KING ASSERTS THAT IT IS CHEAPER TO THE CUSTOMERS TO DEFER THE RECOVERY OF THE RETIREMENT COST. IS HE CORRECT?

A. No. Anytime recovery of plant related costs are deferred, the net embedded costs remain at a higher level than otherwise would be the case. Accordingly, as a result of such a practice, additional carrying costs to finance the investments as well as return is required while those costs are retained on the Company's books and records for longer periods of time. The bottom line is that the deferral of cost recovery costs the ratepayer additional amounts in customer rates.

Q. ON THE BOTTOM OF PAGE 30 TO 33 OF HIS TESTIMONY, MR. KING DISCUSSES THE USE OF THE SFAS 143 APPROACH TO RECOVER RETIREMENT COSTS (COST OF REMOVAL). DO YOU HAVE A RESPONSE TO THIS PROPOSAL?

A. Mr. King goes on for several pages to espouse the supposed virtues of the SFAS 143 procedure (which is generally equivalent to a sinking fund approach). There are numerous fallacies with Mr. King's proposed adoption of the SFAS procedure. First, in developing the applicable recovery of the retirement cost one is not seeking to define the current value of the future expenditure, but instead the task is to define the allocable portion of that cost of removal that should be charged to the current rate payer.

Secondly, if one were to use the SFAS procedure, the methodology produces an added level of complexity into the calculation. Under such a scenario not only does the amount of end of life costs need to be estimated but also the applicable discount rate must be determined.

Next, given changing financial conditions, it is extreme likely that the discount rate would vary widely during the property's life adding significantly to the level of recovery variation throughout the life of the property.

Furthermore, there is an added fallacy with using a discounting approach for capital recovery. For example, the SFAS procedure states that the calculation should be prepared with the Company's risk free rate. This type of calculation has little or nothing to do with the possible discount rate attributable to the many diverse customers that the Company serves. Also, it seems rather odd that a higher risk company (or an individual, if an individual discount rate were utilized) with a higher return rate would allocate less to recover future retirement costs than a lower risk Company. There is simply no valid basis for giving Mr. King's proposed SFAS approach any consideration for capital recovery purposes.

Q. ON PAGE 34, LINES 13 TO 31 AND PAGE 35, LINES1 TO 12 OF HIS TESTIMONY, MR. KING DISCUSSES ADDING THE COST OF REMOVAL TO THE NEW CONSTURCTION COST OF THE REPLACMENT PLANT. HE ALSO DISCUSSES CURRENT EXPENSING OF COST OF REMOVAL

FOR PLANT NOT REPLACED. DO EITHER OF THESE TWO PROPOSALS HAVE ANY MERIT?

A. Absolutely not. First, the proposal to charge the cost of removal to the cost of the new construction has no rational basis, is counter to any and all accounting matching principles, and is not in compliance with the Uniform System of Accounts. As can be seen in my Exhibit No.-___(EMR-4), which is a page from the FERC Gas Uniform System of Accounts, it states equivocally on Page 529 that "cost of removal" shall be charged to the depreciation (reserve) account.

Mr. King's proposal to add the retirement cost (cost of removal) attributable to the current plant in service to the next generation of replacement plant fails any test of reasonableness. The retirement cost (cost of removal) relative to the current plant in service has absolutely no connection or nothing to do with the next generation of plant in service. In this regard, Mr. King's proposal fails the most basic of accounting tests (the matching principle). He is proposing to add the cost from one generation of asset and push its recovery off onto the customers who use the next generation's assets. This is simply an effort to defer cost recovery. The cost recovery system (depreciation) should capture, and appropriately and fairly apportion the total capital cost ratably over the useful life of the asset to the customers benefiting from the service provided by those assets.

Likewise, the proposal to currently expense cost of removal at the end of life for assets not replaced is simply another attempt to defer the appropriate recovery of the estimated cost of removal rather than recover the cost on a time basis from the appropriate customers who benefit from the use of the property.

Q. WHAT STATEMENT DO YOU HAVE REGARDING MR. KINGS POSITION ON PAGE 35, LINES17 to 31 OF HIS TESTIMONY IN WHICH HE STATES THE EXISTENCE OF CURRENT FERC RULES SUPPORTING HIS PROPOSAL TO INCLUDE RETIREMENT COSTS (COST OF REMOVAL) WITH THE NEW REPLACMENT PLANT?

A. Mr. King's testimony in this regard is in error. Within his testimony, Mr. King states that FERC has instituted an accounting change to incorporate retirement cost (cost of removal) into the cost of the new replacement facilities. Furthermore, in his testimony he quotes a definition from the FERC Uniform System of Accounts (USOA), Paragraph 32 of the GAS USOA: **"Replacing or replacement, when not otherwise indicated in the context, means the construction or installation of gas plant in place of property retired, together with the removal of the property retired."**

Exhibit No.-___(EMR-4) is all the selected pages that could be found within the USOA that make any reference to the terms "Replacing or Replacement". I have highlighted the area in each of the included USOA pages where the applicable reference occurs. It is rather obvious from

even a quick review of the applicable pages that Mr. King's assertion and interpretation is incorrect.

Mr. King goes on to infer, and actually states "**if the definition of replacement provided above applies, the addition of a replacement unit should include the cost of removing the property retired.**" Mr. King's statement is totally incorrect. A search of the USOA to view the context in which the words 'Replacing" and "Replacement" are used in the USOA clearly reveals that in no way does FERC state that "retirement cost (cost of removal)" should be charged to the costs of the new plant that is replacing the retired plant. In fact "Paragraph 10 of Page 529 of the USOA specifically states "When a retirement unit is retired from gas plant, with or without replacement, the book cost thereof shall be credited to the gas plant account in which it is included.....If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to gas plant shall be charged to the accumulated provision for depreciation applicable to such property. "**The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation account.**"

It could not be spelled out any clearer; the cost of removal is to be charged to the depreciation reserve, not to the replacement property's original cost as indicated by Mr. King.

Q. DO YOU HAVE ADDITIONAL COMMENTS REGARDIGN MR. KING'S POSITION AND STATEMENT CONCERNING FERC'S ALLEGED

SUPPORT OF HIS PROPOSAL TO CHARGE PLANT RETIREMENT COSTS (COST OF REMOVAL) TO THE COST OF THE NEW REPLACEMENT PLANT?

A. Yes. In the recently released FERC Final Rule in Docket No. RM02-7-000, Order No. 61 (Issued April 9, 2003) concerning changes enacted to the FERC (Gas) Uniform System of Accounts, FERC specifically indicated in Paragraph 36 that removal cost that are not asset retirement obligations are included as a component of depreciation expense and recorded in accumulated depreciation. Furthermore FERC noted in Paragraph 36 that one (1) commenter, the National Association of State Utility Consumer Advocates (NASUCA) recommended that "the Commission exclude costs of removal that does not qualify as a legal retirement obligation from the depreciation accrual and instead capitalize any removal cost related to the asset replaced as part of the costs replacing the utility plant and if no plant replacement occurs, the cost of removal for non-legal retirement obligations should be expensed in the income statement."

FERC rejected that request in saying that the Commission did not propose any changes to its existing accounting requirements for cost of removal for non-legal retirement obligations. FERC went on to say that "the purpose of this rule is to establish uniform accounting requirements for the **recognition of liabilities for legal obligations** associated with the retirement of long lived assets."

This FERC rule is simply a mechanism for defining the liabilities associated with future legal retirement obligations and in no way supports Mr. King's

proposal. In fact, as noted above, a mirror image of his proposal was specifically rejected.

Q. WHAT STATEMENT DO YOU HAVE REGARDING MR. KING'S POSITION (PAGE 36) THAT THE COMMISION SHOULD CHANGE ITS PRACTICE TO ADOPT HIS RECOMMENDATION?

A. Mr. King's SFAS 143 (cost of removal recovery) proposal is unsupported by basic accounting and ratemaking concepts and procedures. Furthermore, Mr. King's proposal to charge removal cost to new construction is in direct conflict with and is specifically inconsistent with the Uniform System of Accounts as just previously discussed.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Appendix A

EARL M. ROBINSON
SUMMARY OF TESTIMONY

Jurisdiction	Client	Docket/Application	Subject
Alberta	Canadian Western Natural Gas Company Limited	980413	Depreciation
Arizona	Arizona Corp. Comm./ Mtn. Bell	9981-E-1051	RCN/RCND *
	Arizona Corp. Comm./ Southwest Gas Corp.	U-1551-80-70	RCN/RCND *
California (State Board of Equali-zation)	MCI Telecommunications Corporation	274	Replacement Cost/ Depr. Repl. Cost
		SAU87-38	Replacement Cost/ Depr. Repl. Cost
		SAU91-101	Replacement Cost/ Depr. Repl. Cost
	Southern California Water Company	ABJ-4	Depreciation
Connecticut	Southern Connecticut Gas Co.	89-09-06	P.I.S. Measures of Value and Depreciation
Delaware	Artesian Water Company	82-20	Depreciation
		87-3	Depreciation
	United Water - Delaware	96-164	Depreciation
		98-98	Depreciation
	Delaware Public Service Comm./ Diamond State Telephone Co.	81-8	P.I.S. Measures of Value and Depreciation
	Tidewater Utilities, Inc/ Public Water and Supply, Inc	99-466	Depreciation
District of Columbia	Potomac Electric Power Co.	F.C. 869	Depreciation
	Washington, DC PSC/ C&P Tel. Corp.	F.C. 777	Depreciation
	Washington, DC PSC/ Potomac Electric Power Co.	F.C. 785	Capital Recovery/
		F.C. 813	Depreciation
FERC	Granite State Gas Transmission, Inc.	RP91-164-000	Depreciation

EARL M. ROBINSON
SUMMARY OF TESTIMONY

Jurisdictions	Client	Docket	Subject
	Paiute Pipeline	RP96-306-000	Depreciation
Florida (County of Duval)	BellSouth Telecommunications	Petitions 1795-1800	Replacement Cost/ Depr. Repl. Cos
(County of St. Lucie)	BellSouth Telecommunications	1999 Petitions	Replacement Cost/ Depr. Repl. Cost
Illinois	Illinois - American Water Company	00-0340	Depreciation
	Illinois Consolidated Telephone Co.	81-0264 82-0623	RCN/RCND * RCN/RCND *
Indiana	Northern Indiana Public Service Company	Cause No. 41746	Depreciation
Massachusetts	Bay State Gas Company	92-111	Depreciation
New Jersey	Borough of Butler/ Butler Elec. Dept.	792-84	Valuation of Plant in Service Customer Revenue and Purchase Power
	Commonwealth Water Co.	842-100	Depreciation
	Consumers New Jersey Water Company	WR00030174	Depreciation
	Garden State Water Co.	WR91091483	Depreciation
	Middlesex Water Company	WR8602-240 WR90080884J WR96110818	Depreciation Depreciation Depreciation
	Monmouth Cons. Water Co.	8312-1113	Depreciation
	New Jersey Water Company	834-292	Depreciation
	United Water Resources (formerly Hackensack Water Co.)	8506-663 WR90080792J WR95070303	Depreciation Depreciation Depreciation

EARL M. ROBINSON
SUMMARY OF TESTIMONY

Jurisdictions	Client	Docket	Subject
	United Water Resources Toms River Water Company	WR95050219	Depreciation
New Hampshire	Northern Utilities, Inc.	DR91-081	Depreciation
New Mexico	New-Mexico American Water Company	2813	Depreciation
New York	New York-American Water Co.	28911	Depreciation
	Spring Valley Water Co., Inc.	89-W-1151 92-W-0645	Depreciation Depreciation
North Carolina	Nantahala Power and Light Co.	E-13, SUB157	Depreciation
Pennsylvania	Borough of Media Water Works	R-912150	Depreciation
	Columbia Gas of Penna.	R-80031129	Depreciation and Valuation
	Commonwealth Telephone Co.	I-00920020	Depreciation
	Keystone Water Company	R-842755 R-842756 R-842759	Capital Recovery/Depreciation Capital Recovery/Depreciation Capital Recovery/Depreciation
	Mid Penn Tel. Corp.	R-80071264	Depreciation
	Penna.-American Water Co.	R-891208	Depreciation
	Penna. Gas & Water Co. - Gas Division	R-821961 R-832475	Depreciation Depreciation
	Penna. Gas & Water Co. - Water Division	R-822102 R-850178 R-870853	Depreciation Capital Recovery/Depreciation Capital Recovery/Depreciation
	Penna. Gas & Water Co. - Scranton Division	R-901726 R-922482	PIS Meas. of Value/Depreciation Depreciation
	Penna. Gas & Water Co. - Spring Brook Division Nesbitt Service Area	R-911966	PIS Meas. of Value/Depreciation

EARL M. ROBINSON
SUMMARY OF TESTIMONY

Jurisdictions	Client	Docket	Subject
	Crystal Lake Service Area	R-922404	PIS Meas. of Value/Depreciation
	Ceasetown/Watres Service Area	R-93266	Depreciation
Pennsylvania (Cont'd)	Penna. Power Company	R-811510	PIS Meas. of Value/Depreciation
		R-821918	PIS Meas. of Value/Depreciation
		R-832409	PIS Meas. of Value/Depreciation
		R-842740	PIS Meas. of Value/Depreciation
		R-850267	PIS Meas. of Value/Depreciation
		R-870732	PIS Meas. of Value/Depreciation
	Pennsylvania & Southern Gas Company	R-870686	Depreciation
	PG Energy Inc.	R-963612	PIS Meas. of Value/Depreciation
		R-984280	PIS Meas. of Value/Depreciation
	Philadelphia Suburban Water Company	R-911892	Depreciation
		R-922476	PIS Meas. of Value/Depreciation
		R-932868	PIS Meas. of Value/Depreciation
	Riverton Consolidated Water Co.	R-842675	Capital Recovery/Depreciation
	United Water - Pennsylvania	R-00973947	Depreciation
	Western Pennsylvania Water Company	R-842621	Capital Recovery/Depreciation
		R-842622	Capital Recovery/Depreciation
		R-842623	Capital Recovery/Depreciation
		R-842624	Capital Recovery/Depreciation
		R-842625	Capital Recovery/Depreciation
	Wellsboro Electric Company	R-00016356	Depreciation
Rhode Island	Providence Gas Company	1914	Depreciation
		2286	Depreciation

EARL M. ROBINSON
SUMMARY OF TESTIMONY

Jurisdictions	Client	Docket	Subject
South Carolina	Lockhart Power Company	87-435-E	Depreciation
Virgin Islands	Virgin Islands Tel. Corp.	264	Depreciation
		314	Depreciation
		316	Depreciation

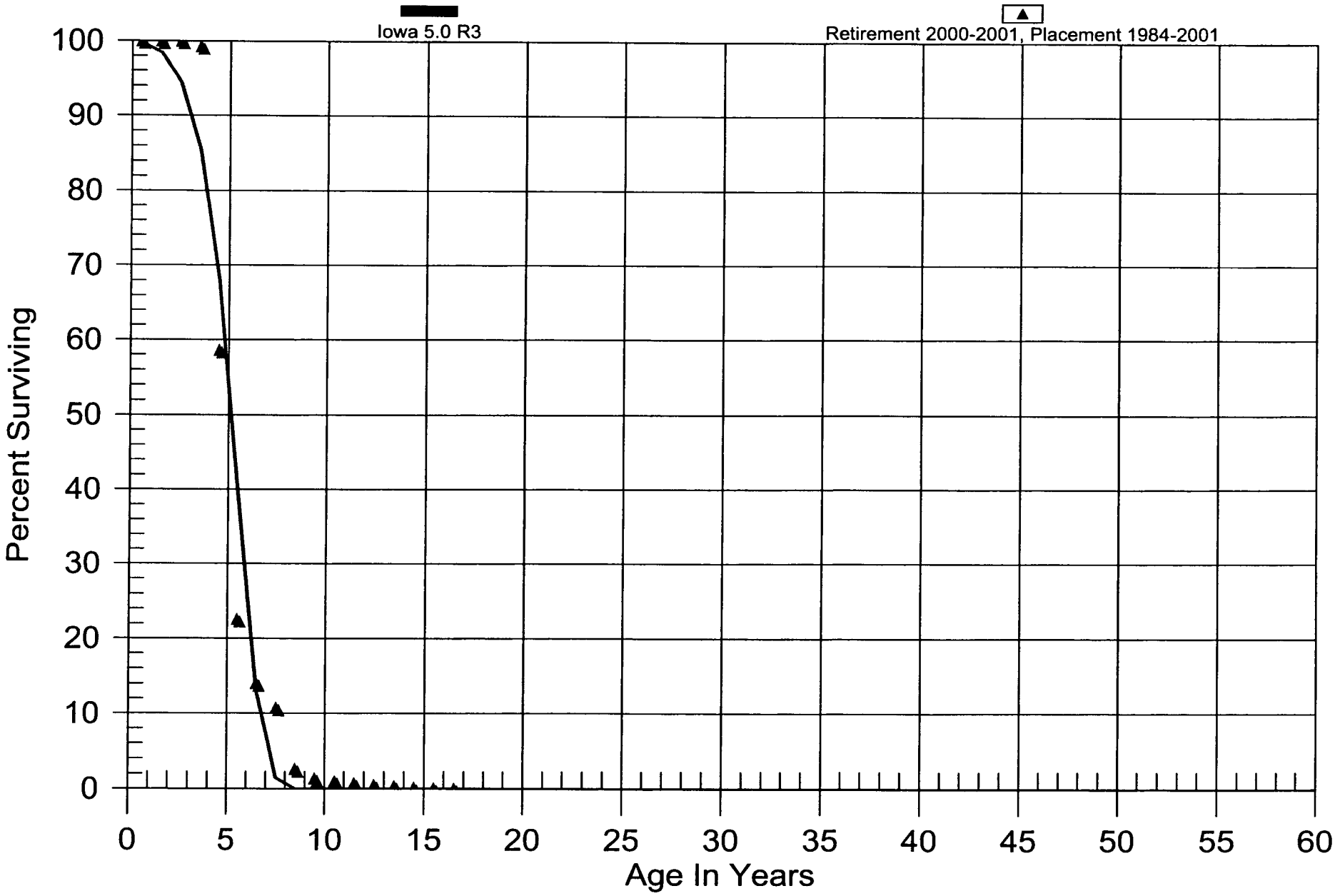
* Reproduction Cost New/Reproduction Cost New Depreciated.

California - American Water Company

All Divisions

372.10 COMPUTER EQUIPMENT

Original And Smooth Survivor Curves

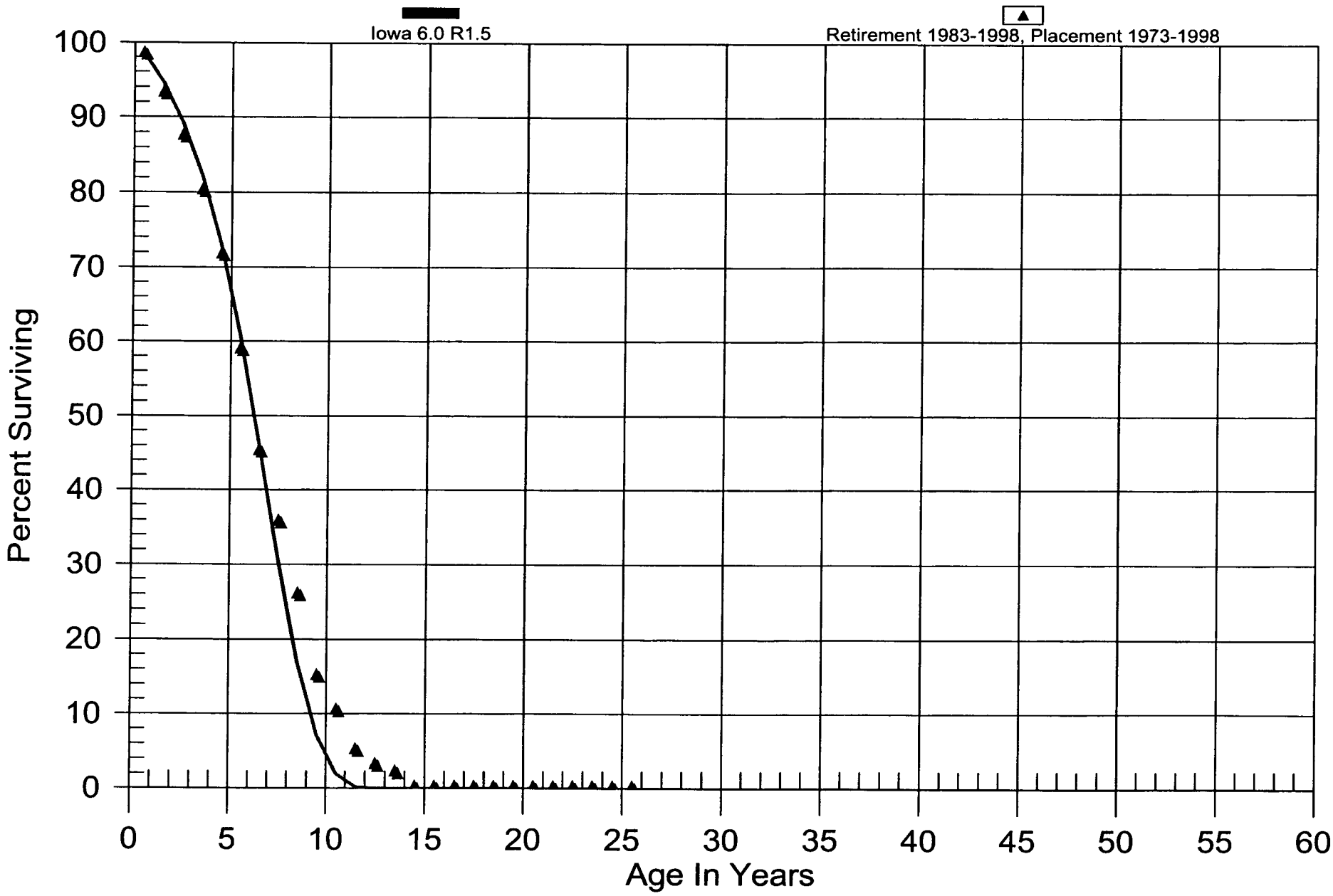


Illinois-American Water Company

All Divisions

340.20 (391.21) PERSONAL COMPUTERS & PERIPHERALS

Original And Smooth Survivor Curves

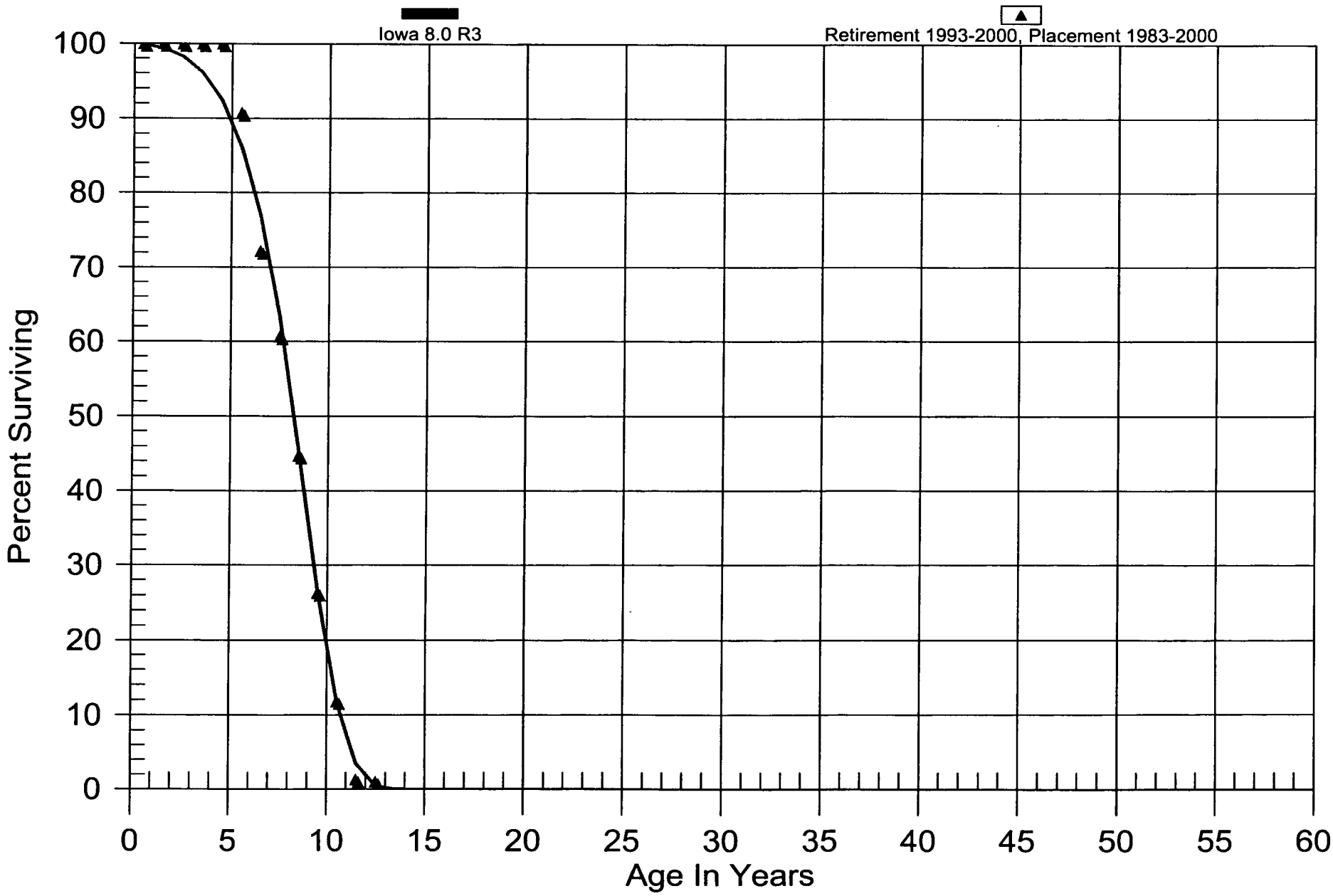


Northern Indiana Public Service Company

Common Plant Division

391.20 COMPUTERS & PERIPHERAL EQUIPMENT

Original And Smooth Survivor Curves

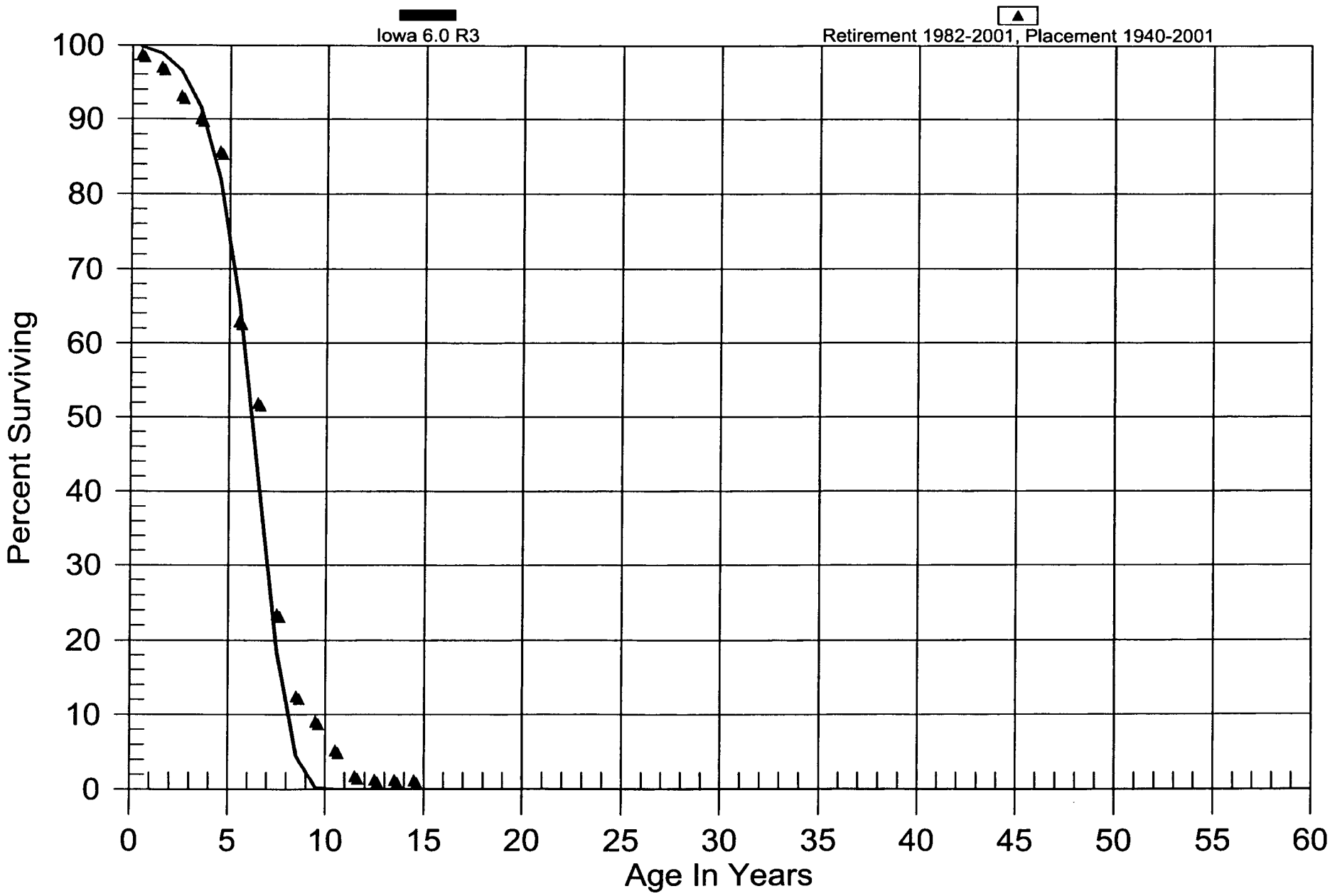


Montana-Dakota Utilities Company

Common Plant

391.30 COMPUTER EQUIPMENT - PC

Original And Smooth Survivor Curves



[Code of Federal Regulations]
[Title 18, Volume 1, Parts 1 to 399]
[Revised as of April 1, 2002]
From the U.S. Government Printing Office via GPO Access
[CITE: 18CFR201]
[Page 509-590]
. . . CHAPTER I--FEDERAL ENERGY REGULATORY COMMISSION, DEPARTMENT OF
ENERGY

PART 201--UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT

AUTHORITY: 15 U.S.C. 717-717w, 3301-3432; 42 U.S.C. 7101-7352, 7651- 7651o.
SOURCE: Order 219, 25 FR 5616, June 21, 1960.
EDITORIAL NOTE: For Federal Register citations affecting part 201, see the List of CFR
Sections Affected in the Finding Aids section of this volume.
EFFECTIVE DATE NOTE: At 58 FR 18006, April 7, 1993, part 201 was amended by redesignating definitions 31 through 39 as 32 through 40 and adding new definition 31; Accounts 182.3 and 254 were added under Balance Sheet Accounts; and Accounts 407.3 and 407.4 were added under Income Accounts. The information collection provisions, will
not become effective until approved by the Office of Management and Budget. A notice will be published in the Federal Register once approval has been obtained.
NOTE: Order 141, 12 FR 8504, Dec. 19, 1947, provides in part as follows:
Prescribing a system of accounts for natural gas companies under the Natural Gas Act. The Federal Power Commission acting pursuant to authority granted by the Natural Gas Act
(58) Stat. 821, as amended; 15 U.S.C. and Sup. 717 et seq.), particularly sections 8(a), 10(a) and 16 thereof, and finding such action necessary and appropriate for carrying out the
provisions of said Act, ordered that:
(a) The accompanying system of accounts, entitled ``Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act," and the rules and regulations contained therein, be adopted;
(b) Said system of accounts and said rules and regulations contained therein be and the same are hereby prescribed and promulgated as the system of accounts and rules and regulations of the Commission to be kept and observed by natural gas companies subject to
the jurisdiction of the Commission, to the extent and in the manner set forth therein;
(c) Said system of accounts and rules and regulations therein contained as to all natural gas companies now subject to the jurisdiction of the Commission, became effective
on January 1, 1940, and as to any natural gas company which may hereafter become

subject
to the jurisdiction of the Commission, they shall become effective as of the date when such
natural gas company becomes subject to the jurisdiction of the Commission.

Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act

Definitions

When used in this system of accounts:

(Non- related Definitions 1-29 deleted to abbreviated content of exhibit)

A. *Production system* shall consist of plant and equipment used in the production of gas. It shall include producing lands and leaseholds, gas rights, other land rights, structures,
drilling and clearing equipment, gas wells, well head equipment, separation and other facilities used in the production of natural gas. The production system ends where the gas enters a gathering system, transmission system or distribution system, as applicable, in accordance with the practices in the pricing area where such system is located.

B. *Transmission system* means the land, structures, mains, valves, meters, boosters, regulators, tanks, compressors, and their driving units and appurtenances, and other equipment used primarily for transmitting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas, to one or more distribution areas. The transmission system begins at the outlet side of the valve at the
connection to the last equipment in a manufactured gas plant, the connection to gathering lines or delivery point of purchased gas, and includes the equipment at such connection that
is used to bring the gas to transmission pressure, and ends at the outlet side of the equipment which meters or regulates the entry of gas into the distribution system or into a storage area. It does
[[Page 511]]
not include storage land, structures or equipment. Pipeline companies, including those companies which measure deliveries of gas to their own distribution systems, shall include
city gate and main line industrial measuring and regulating stations in the transmission function.

C. Distribution system means the mains which are provided primarily for
distributing gas within a distribution area, together with land, structures, valves, regulators,
services and measuring devices, including the mains for transportation of gas from production plants or points of receipt located within such distribution area to other points

therein. The distribution system owned by companies having no transmission facilities connected to such distribution system begins at the inlet side of the distribution system equipment which meters or regulates the entry of gas into the distribution system and ends
with and includes property on the customer's premises. For companies which own both transmission and distribution facilities on a continuous line, the distribution system begins
at the outlet side of the equipment which meters or regulates the entry of gas into the distribution system and ends with and includes property on the customer's premises. The distribution system does not include storage land, structures, or equipment.
D. Distribution area means a metropolitan area or other urban area comprising one or more adjacent or nearby cities, villages or unincorporated areas, including developed areas contiguous to main highways.
30. *Property retired*, as applied to gas plant, means property which has been removed, sold, abandoned, destroyed, or which for any cause has been withdrawn from service.
31. *Regulatory Assets and Liabilities* are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been included in net income determinations in one period under the general requirements of the Uniform System of Accounts but for it being probable: 1) that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or 2) in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts, will be required.

**32. A. *Replacing or replacement*, when not otherwise indicated in the context,
means the construction or installation of gas plant in place of property retired, together
with the removal of the property retired.**

B. *Research, Development, and Demonstration* (RD&D), means expenditures incurred by natural gas companies either directly or through another person or organization
(such as research institute, industry association, foundation, university, engineering company, or similar contractor) in pursuing research, development, and demonstration activities including experiment, design, installation, construction, or operation. This definition includes expenditures for the implementation or development of new and/or existing concepts until technically feasible and commercially feasible operations are verified. Such research, development, and demonstration costs should be reasonably related
to the existing or future utility business, broadly defined, of the public utility or licensee or
in the environment in which it operates or expects to operate. The term includes, but is not
limited to: All such costs incidental to the design, development or implementation of an experimental facility, a plant process, a product, a formula, an invention, a system or

similar items, and the improvement of already existing items of a like nature; amounts expended in connection with the proposed development and/or proposed delivery of substitute or synthetic gas supplies (alternate fuel sources for example, an experimental coal gasification plant or an experimental plant synthetically producing gas from liquid hydrocarbons); and the costs of obtaining its own patent, such as attorney's fees expended in making and perfecting a patent application. The term includes preliminary investigations
and detailed planning of specific projects for securing for customers non-conventional pipeline gas supplies that rely on technology that has not been verified previously to be [[Page 512]]
feasible. The term does not include expenditures for efficiency surveys; studies of management, management techniques and organization; consumer surveys, advertising, promotions, or items of a like nature.

33. *Retained earnings* (formerly earned surplus) means the accumulated net income of the utility less distribution to stockholders and transfers to other capital accounts.

34. *Retirement units* means those items of gas plant which, when retired, with or without replacement, are accounted for by crediting the book cost thereof to the gas plant account in which included.

35. *Salvage value* means the amount received for property retired, less any expenses incurred in connection with the sale or in preparing the property for sale; or, if retained, the amount at which the material recoverable is chargeable to Materials and Supplies, or other appropriate account. 36. Service life means the time between the date gas
plant is includible in gas plant in service, or gas plant leased to others, and the date of its retirement. If depreciation is accounted for on a production basis rather than on a time basis, then service life should be measured in terms of the appropriate unit of production.

37. *Service value* means the difference between original cost and net salvage value of gas plant.

38. *Unsuccessful exploration and development costs*, means exploration and development costs related to efforts which do not directly result in the discovery of commercially recoverable hydrocarbon reserves.

39. *Subsidiary company*, means a company which is controlled by the utility through ownership of voting stock. (See ``Definitions"--item 5B ``Control"). A corporate joint venture in which a corporation is owned by a small group of businesses as a separate and specific business or project for the mutual benefit of the members of the group is a subsidiary company for the purposes of this system of accounts.

40. Utility, as used herein and when not otherwise indicated in the context, means any natural gas company to which this system of accounts is applicable.

FEERC Uniform System of Accounts

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gas introduced into the utility's system necessary to bring the system up to its designed operating capacity or increases therein and which must be maintained in the system in order
to sustain such design operating capacity.
(21) LNG "heel" is the first cost of that minimum quantity of liquefied natural gas necessary to be retained in holding tanks and other facilities for purposes of temperature and/or pressure maintenance.
(22) "Studies" includes the costs of studies such as operational, safety or environmental studies relative to plant under construction. Studies mandated by regulatory
bodies relative to facilities in service, shall be charged to Account 183.2, Other Preliminary Survey and Investigation Charges.
4. *Overhead construction costs.* A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and
damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units
on the basis of the amounts of such overheads reasonably applicable thereto, to the end that
each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the
property is retired.
B. As far as practicable, the determination of pay roll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead
costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.
C. The record supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of each
overhead expenditure charged to each construction work order and to each utility plant account, and the bases of distribution of such costs.
5. *Gas plant purchased or sold.* A. When gas plant constituting an operating unit or system is acquired by purchase, merger, consolidation, liquidation, or otherwise, after the effective date of this system of accounts, the costs of acquisition, including expenses incidental thereto properly includible in gas plant, shall be charged to account 102, Gas Plant Purchased or Sold.

B. The accounting for the acquisition shall then be completed as follows:
(1) The original cost of plant, estimated if not known, shall be credited to account 102, Gas Plant Purchased or Sold, and concurrently charged to the appropriate gas plant in service accounts and to account 104, Gas Plant Leased to Others, account 105, Gas Plant Held for Future Use, 105.1, Production Properties Held for Future Use, and account 107, Construction Work in Progress--Gas, as appropriate.
(2) The depreciation, depletion, and amortization applicable to the original cost of the properties purchased, shall be charged to account 102, Gas Plant Purchased or Sold, and concurrently credited to the appropriate account for accumulated provision for depreciation, depletion or amortization.
(3) The cost to the utility of any property includible in account 121, Nonutility Property, shall be transferred thereto.
(4) The amount remaining in account 102, Gas Plant Purchased or Sold, shall then be closed to account 114, Gas Plant Acquisition Adjustments.
C. If property acquired in the purchase of an operating unit or system is in such physical condition when acquired that it is necessary substantially to rehabilitate it in order to bring the property up to the standards of the utility, the cost of such work, except replacements, shall be accounted for as a part of the purchase price of the property.
D. When any property acquired as an operating unit or system includes duplicate or other plant which will be retired by the accounting utility in the reconstruction of the acquired property or its consolidation with previously

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owned property, the proposed accounting for such property shall be presented to the Commission.

E. In connection with the acquisition of gas plant constituting an operating unit or system, the utility shall procure, if possible, all existing records relating to the property acquired, or certified copies thereof, and shall preserve such records in conformity with regulations or practices governing the preservation of records of its own construction.

F. When gas plant constituting an operating unit or system is sold, conveyed, or transferred to another by sale, merger, consolidation, or otherwise, the book cost of the property sold or transferred to another shall be credited to the appropriate utility plant accounts, including amounts carried in account 114, Gas Plant Acquisition Adjustments. The amounts (estimated if not known) carried with respect thereto in the accounts for accumulated provision for depreciation, depletion, and amortization and in account 252, Customer Advances for Construction, shall be charged to such accounts and the contra entries made to account 102, Gas Plant Purchased or Sold. Unless otherwise ordered by the Commission, the difference, if any, between (a) the net amount of debits and credits and (b) the consideration received for the property (less commissions and other expenses of making the sale) shall be included in account 421.1, Gain on Disposition of Property, or account 421.2, Loss on Disposition of Property. (See account 102, Gas Plant Purchased or Sold.)

Note: In cases where existing utilities merge or consolidate because of financial or operating reasons or statutory requirements rather than as a means of transferring title of purchased properties to a new owner, the accounts of the constituent utilities, with the approval of the Commission, may be combined. In the event original cost has not been determined, the resulting utility shall proceed to determine such cost as outlined herein.

6. *Expenditures on leased property.* A. The cost of substantial initial improvements (including repairs, rearrangements, additions, and betterments) made in the course of preparing for utility service property leased for a period of more than one year, and the cost of subsequent substantial additions, replacements, or betterments to such property, shall be charged to the gas plant account appropriate for the class of property leased. If the service life of the improvements is terminable by action of the lease, the cost, less net salvage, of the improvements shall be spread over the life of the lease by charges to account 404.3, Amortization of Other Limited-Term Gas Plant. However, if the service life is not terminated by action of the lease but by depreciation proper, the cost of the improvements, less net salvage, shall be accounted for as depreciable plant. The provisions of this paragraph are applicable to property leased under either capital leases or operating leases.

B. If improvements made to property leased for a period of more than one year are of relatively minor cost, or if the lease is for a period of not more than one year, the cost

of the improvements shall be charged to the account in which the rent is included, either directly or by amortization thereof.

7. *Land and land rights.* A. The accounts for land and land rights shall include the cost of land owned in fee by the utility and rights, interests, and privileges held by the utility in land owned by others, such as leaseholds, easements, rights-of-way, natural gas rights, and other like interests in land. Do not include in the accounts for land and land rights and rights-of-way costs incurred in connection with first clearing and grading of land and rights-of-way and the damage costs associated with the construction and installation of plant. Such costs shall be included in the appropriate plant accounts directly benefited.

B. Where special assessments for public improvements provide for deferred payments, the full amount of the assessments shall be charged to the appropriate land account and the unpaid balance shall be carried in an appropriate liability account. Interest on unpaid balances shall be charged to the appropriate interest account. If any part of the cost of public improvement is included in the general tax levy, the amount thereof shall be charged to the appropriate tax account.

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Gas Plant Held for Future Use, or 105.1, Production Properties Held for Future Use, as appropriate.

Note: In addition to the accounting records prescribed herein, supplemental records of land and land rights held for future use shall be kept in such manner as to permit the segregation within a reasonable time of the land and land rights constituting (1) productive but nonproducing fields, (2) unproven or undeveloped fields, and (3) storage fields, and to show the following data with respect to each natural gas lease, regardless of the accounting treatment accorded the lease costs; (a) name of lessor, (b) location of leasehold and number or other identification assigned thereto, (c) date and period of lease agreement, (d) first cost of lease including details of the elements of such cost, (e) annual rental provisions, (f) date and cost of drilling, (g) date gas determined to exist, (h) date of completion of first well drilled by the utility in each pool of gas, (i) royalty provisions, (j) amortization and depletion provisions, and (k) date of abandonment of lease.

H. Provision shall be made for amortizing amounts carried in the accounts for limited-term interests in land, so as to apportion equitably the cost of each interest over the life thereof. For the purposes of amortization of natural gas rights, separate interests in land which comprise an interest in a production area may be grouped to form a depletion unit. (See account 111, Accumulated Provision for Amortization and Depletion of Gas Utility Plant, account 404.1, Amortization and Depletion of Producing Natural Gas Land and Land Rights, account 404.3, Amortization of Other Limited-Term Gas Plant, and account 797, Abandonment, leases.)

I. The items of cost to be included in the accounts for land and land rights are as follows:

1. Bulkheads, buried, not requiring maintenance or replacement.
2. Cost, first, of acquisition including mortgages and other liens assumed (but not subsequent interest thereon).
3. [Reserved]
4. Condemnation proceedings, including court and counsel costs.
5. Consents and abutting damages, payment for.
6. Conveyancers' and notaries' fees.
7. Fees, commissions, and salaries to brokers, agents, and others in connection with the acquisition of the land or land rights.
8. [Reserved]
9. Leases, cost of voiding upon purchase to secure possession of land.
10. Removing, relocating, or reconstructing, property of others, such as buildings, highways, railroads, bridges, cemeteries, churches, telephone and power lines, etc., in order to acquire quiet possession.

11. Retaining walls unless identified with structures.
12. Special assessments levied by public authorities for public improvements on the basis of benefits for new roads, new bridges, new sewers, new curbing, new pavements, and
other public improvements, but not taxes levied to provide for the maintenance of such improvements.
13. Surveys in connection with the acquisition, but not amounts paid for topographical surveys and maps where such costs are attributable to structures or plant equipment erected or to be erected or installed on such land.
14. Taxes assumed, accrued to date of transfer of title.
15. Title, examining, clearing, insuring, and registering in connection with the acquisition and defending against claims relating to the period prior to the acquisition.
16. Appraisals prior to closing title.
17. Cost of dealing with distributees or legatees residing outside of the state or county, such as recording power of attorney, recording will or exemplification of will, recording satisfaction of state tax.
18. Filing satisfaction of mortgage.
19. Documentary stamps.
20. Photographs of property at acquisition.
21. Fees and expenses incurred in the acquisition of water rights, and grants.
22. Cost of fill to extend bulkhead line over land under water, where riparian rights are held, which is not occasioned by the erection of a structure.
23. Sidewalks and curbs constructed by the utility on public property.
24. Labor and expenses in connection with securing rights of way, where performed by company employees and company agents.
8. *Structures and improvements*. A. The accounts for structures and improvements shall include the cost of all buildings and facilities to house, support, or safeguard property
or persons, including all fixtures permanently attached to and made a part of buildings and
which cannot be removed therefrom without cutting into the walls, ceilings, or floors, or without in some way impairing the buildings, and improvements of a permanent character
on or to land. Also include those costs incurred in connection with the first clearing and grading of land and rights-

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of-way, and the damage costs associated with construction and installation of plant.
B. The cost of specially provided foundations not intended to outlast the machinery or apparatus for which provided, and the cost of angle irons, castings, etc., installed at the base of an item of equipment, shall be charged to the same account as the cost of the machinery, apparatus, or equipment.
C. Minor buildings and structures may be considered a part of the facility in connection with which constructed or operated and the cost thereof accounted for accordingly when the nature of the structure and facility indicates the correctness of such accounting.
D. Where furnaces and boilers are used primarily for furnishing steam for some particular department and only incidentally for furnishing steam for heating a building and
operating the equipment therein, the entire cost of such furnaces and boilers shall be charged to the appropriate plant account, and no part to the building account.
E. The cost of disposing of materials excavated in connection with construction of structures shall be considered as a part of the cost of such work, except as follows: (a) When such material is used for filling, the cost of loading, hauling, and dumping shall be equitably apportioned between the work in connection with which the removal occurs and
the work in connection with which the material is used; (b) when such material is sold, the
net amount realized from such sales shall be credited to the work in connection with which
the removal occurs. If the amount realized from the sale of excavated materials exceeds the
removal costs and the costs in connection with the sale, the excess shall be credited to the land account in which the site is carried.
F. Lighting or other fixtures temporarily attached to buildings for purposes of display or demonstration shall not be included in the cost of the building but in the appropriate equipment account.
G. The items of cost to be included in the accounts for structures and improvements are as follows:
1. Architects' plans and specifications including supervision.
2. Ash pits (when located within the building).
3. Athletic field structures and improvements.
4. Boilers, furnaces, piping, wiring, fixtures, and machinery for heating, lighting, signaling, ventilating, and air conditioning systems, plumbing, vacuum cleaning systems, incinerator and smoke pipe, flues, etc.
5. Bulkheads, including dredging, riprap fill, piling, decking, concrete, fenders, etc., when exposed and subject to maintenance and replacement.
6. Chimneys.
7. Coal bins and bunkers.
8. Commissions and fees to brokers, agents, architects and others.

9. Conduit (not to be removed) with its contents.
10. Damages to abutting property during construction.
11. Docks.
12. Door checks and door stops.
13. Drainage and sewerage systems.
14. Elevators, cranes, hoists, etc., and the machinery for operating them.
15. Excavation, including shoring, bracing, bridging, refill, and disposal of excess excavated material, cofferdams around foundation, pumping water from cofferdam during
construction, and test borings.
16. Fences and fence curbs (not including protective fences insolating items of equipment, which shall be charged to the appropriate equipment account).
17. Fire protection systems when forming a part of a structure.
18. Flagpole.
19. Floor covering (permanently attached).
20. Foundations and piers for machinery, constructed as a permanent part of a building or other items listed herein.
21. Grading and clearing when directly occasioned by the building of a structure.
22. Holders--Relief.
23. Intrasite communication system, poles, pole fixtures, wires and cables.
24. Landscaping, lawns, shrubbery, etc.
25. Leases, voiding upon purchase to secure possession of structures.
26. Leased property, expenditures on.
27. Lighting fixtures and outside lighting
system.
28. Mailchutes when part of a building.
29. Marquee, permanently attached to building.
30. Painting, first coat.
31. Permanent paving, concrete, brick, flagstone, asphalt, etc. within the property lines.
32. Partitions, including movable.
33. Permits and privileges.
34. Platforms, railings and gratings when constructed as a part of a structure.
35. Power boards for services to a building.

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equipment becomes available for service shall be charged to the appropriate expense accounts, except that tests to determine whether equipment meets the specifications and requirements as to efficiency, performance, etc., guaranteed by manufacturers, made after operations have commenced and within the period specified in the agreement or contract of
purchase, may be charged to the appropriate gas plant account.

10. *Additions and retirements of gas plant.* A. For the purpose of avoiding undue
refinement in accounting for additions to and retirements and replacements of gas plant, all
property shall be considered as consisting of (1) retirement units and (2) minor items of
property. Each utility shall maintain a written property units listing for use in accounting
for additions and retirements of gas plant and apply the listing consistently.

B. The addition and retirement of retirement units shall be accounted for as follows:
(1) When a retirement unit is added to gas plant, the cost thereof shall be added to the appropriate gas plant account, except that when units are acquired in the acquisition of
any gas plant constituting an operating sys- tem, they shall be accounted for as provided in
gas plant instruction 5.

(2) When a retirement unit is retired from gas plant, with or without replacement,
the book cost thereof shall be credited to the gas plant account in which it is included,
determined in the manner set forth in paragraph D, below.

If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to gas plant shall be charged to the accumulated provision for depreciation applicable to such property. The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation

account.

C. The addition and retirement of minor items of property shall be accounted for as follows:
(1) When a minor item of property which did not previously exist is added to plant, the cost thereof shall be accounted for in the same manner as for the addition of a retirement unit, as set forth in paragraph B(1), above, if a substantial addition results, otherwise the charge shall be to the appropriate maintenance expense account.
(2) When a minor item of property is retired and not replaced, the book cost thereof shall be credited to the gas plant account in which it is included;

and, in the event the minor item is a part of depreciable plant, the account for accumulated provision for depreciation shall be charged with the book cost and cost of removal and credited with the salvage.

If, however, the book cost of the minor item retired and not replaced has been or will be accounted for by its inclusion in the retirement unit of which it is a part when such unit is retired, no separate credit to the property account is required when such minor item is retired.
(3) When a minor item of depreciable property is replaced independently of the retirement unit of which it is a part, the cost of replacement shall be charged to the maintenance account appropriate for the item, except that if the replacement effects a substantial betterment (the primary aim of which is to make the property affected more useful, more efficient, or of greater durability, or of greater capacity), the excess cost of the replacement over the estimated cost at current prices of replacing without betterment shall be charged to the appropriate gas plant account.
D. The book cost of gas plant retired shall be the amount at which such property is included in the gas plant accounts, including all components of construction costs. The book cost shall be determined from the utility's records and if this cannot be done it shall be estimated. Utilities must furnish the particulars of such estimates to the Commission, if

requested. When it is impracticable to determine the book cost of each unit, due to the relatively large number or small cost thereof, an appropriate average book cost of the units,
with due allowance for any differences in size and character, shall be used as the book cost
of the units retired.
E. The book cost of land retired shall be credited to the appropriate land account. If the land is sold, the difference

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7. General training and instruction of employees by supervisors whose pay is charge- able hereto. Specific instruction and training in a particular type of work is chargeable to the appropriate functional account. (See Gas Plant Instruction 3(19).)
8. Secretarial work for supervisory personnel, but not general clerical and stenographic work chargeable to other accounts. Expenses:
9. Consultants' fees and expenses.
10. Meals, traveling and incidental expenses.
2. *Maintenance.* A. The cost of maintenance chargeable to the various operating expense and clearing accounts, includes labor, materials, overheads and other expenses incurred in maintenance work. A list of work operations applicable generally to utility plant is included
hereunder. Other work operations applicable to specific classes of plant are listed in functional maintenance expense accounts.
B. Materials recovered in connection with the maintenance of property shall be credited to the same account to which the maintenance cost was charged.
C. If the book cost of any property is carried in account 102, Gas Plant Purchased or Sold, the cost of maintaining such property shall be charged to the accounts for maintenance of property of the same class and use, the book cost of which is carried in other gas plant in service accounts. Maintenance of property leased from others shall be treated as provided in operating expense instruction 3.
ITEMS
1. Direct field supervision of maintenance.
2. Inspecting, testing, and reporting on condition of plant specifically to determine the need for repairs, replacements, re- arrangements and changes and inspecting and testing
the adequacy of repairs which have been made.
3. Work performed specifically for the purpose of preventing failure, restoring serviceability or maintaining life of plant.
4. Rearranging and changing the location of plant not retired.
5. Repairing for reuse materials recovered from plant.
6. Testing for, locating and clearing trouble.
7. Net cost of installing, maintaining, and removing temporary facilities to prevent interruptions in service.
8. Replacing or adding minor items of plant which do not constitute a retirement unit. (See gas plant instruction 10.)
3. *Rents.* A. The rent expense accounts provided under the several functional groups of expense accounts shall include all rents, including taxes paid by the lessee on leased property, for property used in utility operations, except (1) minor amounts paid for occasional or infrequent use of any property or equipment and all amounts paid for use of equipment that, if owned, would be includible in plant accounts 391 to 398, inclusive, which shall be treated as an expense item and included in the appropriate functional account

and (2) rents which are chargeable to clearing accounts, and distributed therefrom to the appropriate account. If rents cover property used for more than one function, such as production and transmission, or by more than one department, the rents shall be apportioned to the appropriate rent expense or clearing accounts of each department on an
actual, or, if necessary, an estimated basis.
B. When a portion of property or equipment rented from others for use in connection with utility operations is subleased, the revenue derived from such subleasing shall be credited to the rent revenue account in operating revenues: Provided, however, That
in case the rent was charged to a clearing account, amounts received from subleasing the property shall be credited to such clearing account.
C. The cost, when incurred by the lessee, of operating and maintaining leased property, shall be charged to the accounts appropriate for the expense if the property were owned. D. The cost incurred by the lessee of additions and replacements to gas plant leased
from other shall be accounted for as provided in gas plant instruction 6.
4. *Training costs*. When it is necessary that employees be trained to specifically operate or maintain plant facilities that are being constructed, the related costs shall be accounted for as a current operating and maintenance expense. These expenses shall be charged

FEERC Uniform System of Accounts

Special Instructions to Accounts 117.1, 117.2 and 117.3

The investment in and use of system gas included in Account 117.1, Gas Stored--Base Gas, and Account 117.2, System Balancing Gas, may be accounted for using either the
``fixed asset'' method or an ``inventory'' method as set forth below. The cost of stored gas included in Account 117.3 must be accounted for using an inventory method.

(a) *Inventory Method*--Gas stored during the year must be priced at cost according to generally accepted methods of cost determination consistently applied from year to year. Transmission expenses for facilities of the utility used in moving the gas to the storage area and expenses of storage facilities cannot be included in the inventory of gas except as may be authorized or directed by the Commission.

Withdrawals of gas must be priced using the first-in-first-out, last-in-first-out, or weighted average cost method, provided the method adopted by the utility is used consistently from year to year and appropriate inventory records are maintained. Approval
of the Commission must be obtained for any other pricing method, or change in the pricing
method adopted by the utility.

Adjustments for inventory losses related to gas held in underground reservoirs due to cumulative inaccuracies of gas measurements, or from other causes, must be charged to
Account 823, Gas Losses. Losses of system gas not associated with underground reservoirs must be charged to Account 813, Other Gas Supply Expenses.

(b) *Fixed Asset Method*--When replacement of the gas is made, the amount carried in Account 117.4 for such volumes must be cleared with a contra entry to Account 808.2, Gas Delivered to Storage--Credit. Any difference between the utility's cost of replacement
gas volumes and the amount cleared from Account 117.4 must be recognized as a gain in Account 495, Other gas revenues, or as a loss in Account 813, Other gas supply expenses,
with contra entries to Account 808.2.

Adjustments for inventory losses related to gas held in underground reservoirs due to cumulative inaccuracies of gas measurements, or from other causes, must be charged to
Account 823, Gas Losses. Losses of system gas not associated with underground reservoirs must be charged to Account 813, Other Gas Supply Expenses. Gas losses must be priced at the market price of gas available to the utility in the month the loss is recognized.

Gas owned by the utility and injected into its system will be deemed to satisfy any encroachment on system gas first before any other use.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **24th day of April, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Notice of Rescheduled Hearing

The envelope was addressed as follows:

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 1940 0005 3425 8636

William Pearce
P O Box 400
Bismarck ND 58502-0400
Cert. No. 7001 1940 0005 3425 8643

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 1940 0005 3425 8650

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Sandra L Scott
Notary Public

Subscribed and sworn to before me
this **24th day of April, 2003**.

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

143 **PU-399-02-183** Pages: 5
Affidavits of Service
by Public Service Commission
04/24/2003 CC: Comm Legal PUD (3) Mike ALJ

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **24th day of April, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Notice of Rescheduled Hearing

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **24th day of April, 2003**.

Sandra L. Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

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White Plains NY 10601-4425

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Denver CO 80202-4167

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Bismarck ND 58501

KBMW-AM
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Wahpeton ND 58074-1115

KDAK AM
Box 50
Carrington ND 58421-0050

Rod Kleinjan
KDIX AM Radio
119 2nd Ave W
Dickinson ND 58601-5115

KDLR AM-FM
Box 190
Devils Lake ND 58301-0190

KEYZ-AM
PO Box 2048
Williston ND 58802-2048

Jeff Alexander
KFYR-AM Radio
PO Box 1738
Bismarck ND 58502-1738

KHRT AM
PO Box 1210
Minot ND 58702-1210

KMOT TV
Box 1120
Minot ND 58702-1120

KNDK-AM
HCR 5 Box 9
Langdon ND 58249

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

KOVC-AM
PO Box 994
Valley City ND 58072-0994

KSJB AM and KSJZ FM Radio
PO Box 5180
Jamestown ND 58402-5180

KTGO-AM
Box 457
Tioga ND 58852-0457

News Director
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Drawer B
Dickinson ND 58602

KXMC TV
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KXPO AM & FM Radio
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Grafton ND 58237

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Mandan ND 58554-0727

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Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

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Williston ND 58802-1287

KXMB TV
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Bismarck ND 58502-1617

KXMD-TV
PO Box 790
Williston ND 58802-0790

C W Fox
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Mike Foley
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Scott Speaker
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Washington DC 20005-2150

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

APPROVED
DATE: 4-23-03
KMF

MOTION

April 23, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission issue a Notice of Rescheduled Hearing in Montana-Dakota Utilities Co.'s Natural Gas Rate Increase application in Case No. PU-399-02-183.

sdh

142 PU-399-02-183 Pages. 1
Motion
by Public Service Commission
04/23/2003 CC: Comm Legal PUD (3) Mike ALJ .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

NOTICE OF RESCHEDULED HEARING

April 23, 2003

The hearing in this proceeding that was originally scheduled for April 22, 2003, has been rescheduled to July 1, 2003, beginning at 8:30 a.m. (CDT), in the Commission Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota 58505-0480.

For more information, contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400; or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or braille materials please notify Jon Mielke, Executive Secretary.

PUBLIC SERVICE COMMISSION

Susan E. Wefald	**Tony Clark**	**Leo M. Reinbold**
Commissioner	**President**	**Commissioner**

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Notice of Rescheduled Hearing

by Public Service Commission

04/23/2003 CC: Comm Legal PUD (3) Mike ALJ

APPROVED
DATE: 4-9-03
KMF

MOTION

April 9, 2003

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-399-02-183

I move the Commission extend the final day for filing and service of Montana-Dakota Utilities Co.'s prepared rebuttal testimony and exhibits from April 14, 2003, to April 28, 2003, in Case No. PU-399-02-183, and reschedule the hearing currently set for April 22, 2003.

ijs

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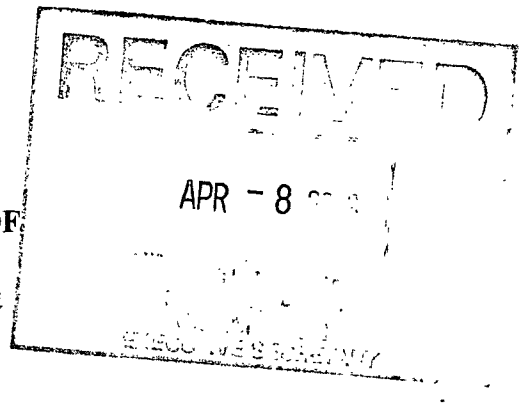
Motion extending finday day for filing
rebuttal testimony
by Public Service Commission

04/09/2003 CC: Comm Legal PUD (3) Mike ALJ .

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Application of the Montana-Dakota Utilities Company for an Increase in Gas Distribution Rates – Depreciation Investigation	))))	Docket No. PU-399-02-183



DIRECT TESTIMONY OF

CHARLES W. KING

ON BEHALF OF
THE COMMISSION ADVOCATE STAFF

April 7, 2003

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Direct Testimony of Charles W King on behalf of the Comm. Advocate Staff by Snavely King Majoros O'Connor & Lee, Inc.

04/08/2003 CC: Comm Legal PUD (3) Mike ALJ

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DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 13 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 500 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Staff of the North Dakota Public Service Commission.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of my testimony is to recommend depreciation rates for the gas and common plant of Montana-Dakota Utilities ("MDU" or "the Company"). In the process, I will review and critique the depreciation study submitted by AUS Consultants ("AUS") on behalf of MDU.

Q. PLEASE DESCRIBE THE PROCESS YOU USED IN PREPARING THIS TESTIMONY.

A. I began by requesting the Company to provide me with the same data that it had provided its consultants, AUS. Having reviewed the data, I then input it into our Company's depreciation analysis software to test the validity of AUS' results. I also prepared a number of data requests and carefully read the Company's responses. Independently, I evaluated the approach used by AUS to the treatment of salvage and retirement costs, and I developed the alternatives that I shall discuss in my testimony. I then prepared the schedules found in my Exhibit____(CWK-1). The calculations underlying these schedules are found in my workpapers. The workpapers were prepared and the calculations were conducted either by myself or under my supervision.

Summary of Recommendations

Q. WHAT DEPRECIATION RATES DO YOU RECOMMEND FOR MDU?

A. My recommended depreciation rates and depreciation expense, based on year-end 2001 plant balances, are set forth in Column (f) of Schedules 1 and 3 of Exhibit____(CWK-1) and in the final columns of Schedules 2 and 4. The following table compares the existing composite depreciation rates with those recommended by the Company and by myself on behalf of the Commission Staff:

Table 1
Category Depreciation Rates

Functional Category	Existing	Company Proposed	Staff Recommended
Gas Distribution	6,758,717	6,082,612	3,535,250
Gas General	936,037	1,927,778	990,871
Common	2,167,043	2,666,460	1,955,583

Table 2 summarizes the changes from present accruals proposed by the Company and recommended by Staff:

Table 2
Staff Recommended Changes in Category Depreciation Accruals
Based on Plant Balances on December 31, 2001

Functional Category	From Existing Rates	From Company Proposed
Gas Distribution	(3,223,467)	(2,547,362)
Gas General	54,834	(936,907)
Total Gas	(3,168,633)	(3,484,269)
Common	(211,460)	(710,877)

DEPRECIATION- GENERAL

Q. WHAT IS DEPRECIATION?

A. In 1958, the National Association of Railroad and Utility Commissioners sanctioned the following definition of depreciation:

> "Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[1]

The second commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[2]

If depreciation can be defined in a single sentence, I would say that it is the process of recovering the initial investment in tangible capital assets, adjusted for salvage, in a systematic fashion over the useful service life of the plant, recognizing that utility plant is typically a group of investments.

Q. CAN DEPRECIATION BE CALCULATED WITH PRECISION?

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[1] *Uniform System of Accounts for Class A and Class B Electric Utilities,* 1958, rev. 1962.

A. No. Depreciation can no more be calculated with precision than can the required rate of return to equity investors. Both are developed from analyses that, while based on quantitative values, require considerable application of judgment. In the case of rate of return, that judgment pertains to the earnings expectations of investors as indicated by the stock market and corporate financial data. In the case of depreciation, the judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements.

Q. HOW DOES THIS JUDGEMENTAL CHARACTERISTIC OF DEPRECIATION INFLUENCE THE COMMISSION'S APPROACH TO THE SUBJECT?

A. The Commission must recognize that the development of depreciation rates is not a refined science subject to mathematical precision. Because depreciation analysts use judgment in their estimation of depreciation, the Commission must necessarily exercise its own judgment in assessing the rationale and data that underlie alternative depreciation rates. This is why, in this proceeding, the Commission must choose among depreciation rates that yield widely differing annual depreciation accruals.

Q. WHAT ARE THE BASIC PARAMETERS REQUIRED TO DEVELOP A DEPRECIATION RATE?

A. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the plant. The reciprocal of that number can be used as the depreciation rate.

However, because most utility depreciation is applied to accounts that are multiple units of plant, it is usually necessary to estimate the dispersion of retirements around an average service life. In the gas and electric utility

[2] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1.*

industries, this dispersion is usually described in terms of "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the retirements are grouped around the average service life and whether they tend to occur more rapidly before, after or coincident with the average service life.

Another parameter that is typically included in the calculation of a depreciation rate is net salvage. Net salvage is the difference between the positive scrap value of the asset's material and the cost of dismantling and removing the asset when it is retired. It is expressed as a ratio to the cost of the asset and included as a subtraction (when salvage value exceeds removal cost) or an addition (when removal cost exceeds salvage) to the amount to be recovered in depreciation charges. With a few exceptions (e.g. vehicles, work equipment) most gas utility plant has a higher removal cost than its salvage value, so that the inclusion of net salvage in depreciation adds to the amount to be recovered.

Finally, virtually all major utilities, including MDU, employ what is known as "remaining life depreciation." This procedure computes the depreciation rate by dividing the unrecovered net investment, adjusted for net salvage, by the estimated remaining years of the asset (or group of assets). It effectively ensures that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

Q. PLEASE ILLUSTRATE HOW THE PARAMETERS YOU HAVE JUST DESCRIBED ARE USED TO DEVELOP DEPRECIATION RATES?

A. Beginning with the simplest example, assume a single asset with a 20 year life. Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume that the asset is expected to have salvage value equivalent to 5 percent of its investment value. The depreciation rate declines:

$$\frac{1-.05}{20} = \frac{.95}{20} = 4.75\%$$

Assume next that the cost of removing this asset amounts to 15 percent of its value. The depreciation rate increases:

$$\frac{1-.05+.15}{20} = \frac{1.10}{20} = 5.55\%$$

This is called a "whole life" rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional items of data: the original investment, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost $1 million and that past depreciation charges have recovered $400,000. This means that we have yet to recover $600,000 in original cost, plus a negative net salvage (i.e. net cost of removal) amounting to 10% of the original cost, or $100,000. The total amount yet to be recovered is thus $700,000. Let us further assume that the asset is 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life years:

$$\frac{\$700,000}{10 \text{ years}} = \$70,000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this case:

$$\frac{\$70,000}{\$1,000,000} = 7.0\%$$

SERVICE LIFE ESTIMATION

Q. WHAT INFORMATION DID YOU RECEIVE FROM MDU TO ASSIST YOU IN YOUR STUDY OF PLANT ACCOUNT SERVICE LIVES?

A. I received the record of plant additions, retirements, transfers, adjustments, and balances for each account each year as far back as 1920. This information I refer to as "vintage data." I also received a record of plant retirements by year of placement for most of the major plant accounts for each year since 1977. I refer to this information as "actuarial data."

Q. WERE THERE ANY PROBLEMS WITH THESE DATA?

A. Yes. During the World War II years, the data show zero additions and zero retirements. Either plant records were not maintained in those years, or there actually was no plant activity due to the war. In either case, the effect is to distort the pattern of plant activity, that is, the typical rate of additions and retirements. Unfortunately, the Simulated Plant Record procedure requires data from the inception of each account, so I have left these zeros in the record.

Additionally, there have been a number of transfers and adjustments to the plant balances over the years. To adjust the data to reflect these changes requires knowledge of the source of the inward transfers and the destination of the outward transfers. It also requires knowledge of the basis for each of the adjustments. Aside from "Crookston Adjustment" for plant transferred out in 1985, I do not have the required information to correct the data for these transfers and adjustments. Accordingly, with the exception of 1985, I have accepted the year-end balances as though they were the result solely of additions and retirements since the previous year end.

Finally, for many of the smaller accounts there was insufficient plant activity, that is, additions and retirements, to perform reliable statistical studies. For most of these accounts, I accepted the either the existing life estimates or those made by AUS Consultants, who prepared the Company's depreciation study.

Q. WHAT LIFE STUDIES DID YOU PERFORM?

A. I performed two types of life studies for each account for which there were sufficient data, Simulated Plant Record ("SPR") studies and actuarial studies.

Q. IS THERE A SOURCE WHERE THE COMMISSION COULD FIND DETAILED EXPLANATIONS OF THESE STUDY METHODOLOGIES?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") has published a manual titled, "Public Utility Depreciation Practices," the latest edition of which is dated August 1996. This manual provides a full description of the theories behind depreciation, the procedures for studying it, the application of depreciation, and its effect on a utility's financial performance.

Q. YOUR RECOMMENDATIONS SHOW A NUMBER, A LETTER AND ANOTHER NUMBER, WHAT IS THE MEANING OF THESE LETTERS AND NUMBERS?

A. Schedule 2, Column (i) of Exhibit_____(CWK-1) contains entries such as 65 R2.5. The first number is the estimated average service life. The R1.5 is the retirements dispersion curve. There are 31 of these "Iowa" curves, so named because they were developed at Iowa State University.[3] They describe two variables: the dispersion of unit retirements around the average life of the account,

[3] For a complete discussion of Iowa Curves, see Appendix A, part 3 of *Public Utility Depreciation Practices*, National Association of Regulatory Utility Commissioners, August 1996.

and the skewing of rate of those retirements before and after the average service life.

The first variable, dispersion, is reflected in the numerical subscripts, which range from 0 to 6, with 0 representing an almost even distribution of retirements over the account's total life, and 6 representing a very tight grouping of unit retirements at the time that the average service life is reached.

The second variable, the pattern of the rate of retirements before and after the average service life, is represented by the letter prefixes. "S" stands for symmetrical, meaning that the pattern of growing unit retirements before the average service life is repeated by declining unit retirements following the average service life. "R" means right-modal and is typical of plant that experiences relatively little retirement activity in its early years but then retires fairly rapidly once it reaches its average life. Human beings experience a right-modal retirements dispersion. "L" implies the opposite condition – a large amount of "infant mortality," with the survivors by the time the average life is reached living a relatively long time. Automobiles may be a good example of an "L" type retirements dispersion.

There are other letter descriptors: "O" curves refer to exponential retirements, where a percentage of the existing plant retires each year. "SQ" is a square dispersion, where all retirements occur at once. The opposite is "SC," where the same number of retirements occur each year throughout the service life of the plant.

Q. PLEASE DESCRIBE THE SPR STUDIES.

The SPR study procedure is a trial and error mechanism whereby a computer program fits alternative Iowa Curves and average service life combinations to the record of plant additions, retirements and balances.

The SPR – Balances program measures the degree to which various combinations of Iowa curves and service lives applied to the plant additions each year yield the plant balances in subsequent years. The degree of fit is measured by sum of the squared differences between the predicted plant balances and the actual balances. When the square root of those differences is divided into the average of the actual balances, the result is a "conformance index." The reciprocal of the conformance index is called the "index of variation." The lower that index, the better the fit.

Another test of SPR results is the "retirements experience index," which measures the maturity of the account under each curve-life combination. A retirements experience index of 100 indicates that the account has experienced a full life cycle, that is, all of the plant placed in the oldest vintage is now retired. An index of 50 suggests that the account is only half way through its life cycle. In general, SPR results with retirements experience indexes less than 50 are considered to have little value, while those over 75 are considered of significant value.

The output of SPR studies is a listing of curve-life combinations in ascending order of their index of variation. Those results are presented in Exhibit_____(CWK-2) for each account for which data were available.

Q. PLEASE DESCRIBE THE ACTUARIAL STUDIES.

A. Actuarial studies are far more precise than SPRs, but they require considerably more data and, to be effective, the data must be fairly "thick," that is, they must reflect a fairly large number of retirements. Actuarial studies use the record of retirements by date of placement, which means that the age of each retirement must be known. With this knowledge, it is possible to compute the history of retirements at each age, and from that record, to fit Iowa curve and service life combinations that reproduce that history.

Unfortunately, in the case of MDU, the actuarial data runs back only to 1976. The Company was able to estimate the age of retirements from that year on, but not earlier. The result is that we have a record of aged retirements only during the past 25 years, which reduces the "thickness" of the actuarial data, so critical to the effectiveness of this method.

The output of actuarial studies is a fit of an Iowa curve and service life to actual aged retirements that can be displayed graphically. That graphical presentation for the three best fits for the accounts for which there are actuarial data is presented in Exhibit_____(CWK-3). The exhibit also contains the Observed Life Tables ("OLT") for each account.

In many cases the fits show lives in excess of a century, which is totally counterintuitive. The reason for these results can be seen in the OLTs. With a few exceptions, the percent surviving does not decline with age, as intuitively it should. That is because there have been inadequate observations of aged retirements to establish a pattern from which can be drawn conclusions as to the expected life of the surviving plant. As a result, the actuarial data have only a limited value in this analysis.

Q. DID THESE STUDIES YIELD PRECISE INDICATIONS OF SERVICE LIFE?

A. No. In many cases, the best SPR fits were associated with curve and life combinations that had inadequate retirement experience indices. As a consequence, I was required to use judgement and, in two cases, the evidence of other utilities' service lives, to develop my service life recommendations. In those cases where totally inadequate data exist, I have usually adopted either the current life and survivor curves or those chosen by AUS.

Q. WHAT ARE YOUR SERVICE LIFE RECOMMENDATIONS FOR THE DISTRIBUTION PLANT ACCOUNTS?

A. My life-curve recommendations are shown in column (i) of Schedule 2 of Exhibit_____(CWK-1).

For Account 374 – Rights of Way, I have adopted the 65 year R2.5 parameters recommended by AUS. The data are inadequate to propose any alternative parameters for this very long-lived account.

For Account 375 – Distribution Measuring and Regulating Structures and Improvements, I have selected 55 years with a S1.5 Iowa curve. The five best fitting SPR life-curve combinations are arrayed around this result.

For Account 376 – Mains, I have selected 58 years. This is a shorter life than the first nine combinations from the SPR analysis, and it is also less than the results indicated by the actuarial studies. A life in the range of 65 to 80 years might be justified by the study output, but the American Gas Association indicates that 80 years is the maximum life adopted by any gas utility in its survey, and the average is 54 years. Exhibit_____(CWK-4) is a redacted summary of that survey, which covers the Mains and Service accounts. Accordingly, I have selected the best SPR fit that achieves a retirement experience index of more than 75.

The existing depreciation parameter for the Mains account is only 36 years. Because of the very great increase in the service life estimate and the modification to the net salvage ratio that I will discuss shortly, I propose to use a "whole life" rate for this account. This rate does not attempt to recover the past over-accrual of depreciation. Rather, it implicitly assumes that there is no excess or deficiency in the depreciation reserve. By using a whole life rate, rather than a remaining life rate, I ameliorate the effect of the very dramatic change in parameters that I am proposing.

For Account 378 – Measuring and Regulating Station Equipment – General, I have selected 50 years with an SC curve. This is the best SPR result that reflects a retirement experience index greater than 75.

For Account 379 – Measuring and Regulating Station Equipment – City Gate, I have selected a 40 year life with an S1 Iowa curve. Again, this reflects the best SPR result with a retirement experience index greater than 75.

For Account 380 – Services, I have selected 55 years. This is a shorter life than the first six combinations from the SPR analysis, and it is also less than the results indicated by the actuarial studies. A life in the range of 60 to 80 years might be justified by the study output, but Exhibit_____(CWK-4) shows that 63 years is the maximum life adopted by any gas utility in the American Gas Association survey, and the average is 40 years. Accordingly, I have selected the best SPR fit that achieves a retirement experience index of more than 75. Again, as in the case of the Mains account, I propose a whole life rate that does not attempt to recover the past over-accruals in the depreciation reserve.

For Account 381 – Meters, I have selected 35 years with an R2.5 Iowa curve. All of the SPR results indicate a longer life, but the industry standard for this account is approximately 35 years.

For Account 383 – Service Regulators, I have selected 40 years and an R1 curve. The 40 year life is the approximate mid-point of the best SPR results with retirement experience indices in the 67 to 80 range.

Not surprisingly, the SPR results for Account 385 – Industrial Measuring and Regulating Equipment were similar to those for Account 383, so I have recommended the same life and survivor curve parameters.

Account 386 – Miscellaneous Equipment consists mostly of CNG refueling station equipment. The historical record, as disclosed by the SPR study, suggests a very long life, and the high level of the depreciation reserve (70%) indicates that the account may have been over-depreciated. Accordingly, I am selecting 20 year life with an R2 Iowa curve for this account.

For Account 387.5 – Other Distribution Equipment I have selected a 20 year life and an L4 Iowa curve. This combination conforms to the general pattern of SPR results, exclusive of the first two fits, which yield much longer lives but with lower retirement experience indices.

Q. HOW DO YOUR RECOMMENDATIONS COMPARE WITH THOSE OF AUS CONSULTANTS?

A. A comparison of my recommended life and curve parameters with those of AUS Consultants is as follows:

Table 3
Distribution Plant Life and Survivor Curves

		Staff Recommended		AUS Consultants	
		ASL	Curve	ASL	Curve
374.00	Rights of Way	65	R2.5	65	R2.5
375.00	Distr. Meas & Reg. Station Structures	55	S1.5	55	R2.5
376.00	Distribution Mains	58	R1.5	45	R3
378.00	Meas. & Reg Station Eqpt – General	50	SC	40	R1
379.00	Meas. & Reg Station Eqpt - City Gate	40	S1	35	R2
380.00	Services	55	R1	40	R3
381.00	Meters	35	R1.5	35	R2.5
383.00	Service Regulators	40	R1	35	R3
385.00	Industrial Meas. & Reg Station Eqpt.	40	R1	35	R2
386.00	Miscellaneous Equipment	20	R2	15	R3
387.10	Cathodic Protection Equipment	20	L4	20	R1.5
387.20	Other Distribution Equipment	20	L4	25	R3

The most significant differences are those involving Accounts 376 and 380, Mains and Services because these two account together represent 65 percent of

the Company's total gas plant. For this reason, changes in the life assumptions for these accounts have the greatest effect on the Company's overall depreciation recovery. Additionally, I should note that the table simplifies AUS' recommendation, because AUS has disaggregated several of the accounts into sub-accounts, four in the case of mains and three in the case of services. AUS has similarly disaggregated Account 387, Other Distribution Equipment?

Q. WHY ARE YOUR LIFE RECOMMENDATIONS DIFFERENT FROM THOSE OF AUS?

A. I cannot say. Exhibit_____(CWK-5) presents copies AUS' SPR results. They are in virtually identical format as the my SPR results in Exhibit_____(CWK-2). These tabulations, which were not included in AUS' report, do not support the life parameters that AUS selected.

For example, AUS selected 45 years as its service life for the Mains account. AUS' SPR output shows that 45 years is the 20th from the best fit of all the life/curve combinations. The 55 years I recommend is the 11th best fit. Had I applied my criterion of selecting the best fit with a retirement experience index of 75 or greater to the AUS output, my recommendation would have been for a Mains service life of 62 years, the eighth best fit.

A similar result can be seen with respect to Account 380 – Services. AUS' SPR output table shows that the 40 year service life selected for this account is the 14th best fit – all better fits yield longer service lives. The best fit that yields a retirement experience index greater than 75 shows a service life indication of 54 years, one year short of the 55 years I have recommended.

Similar effects can be seen in the other accounts where I have selected shorter lives than AUS: Accounts 383, 385, and 386. The AUS report does not explain why it ignored the results of its own SPR studies.

Q WHY HAVE YOU NOT DISAGGREGATED THE MAINS, SERVICES AND OTHER EQUIPMENT ACCOUNTS, AS AUS HAS DONE?

A. First, I did not have the disaggregated data by which to perform studies of the subaccounts. More important, I do not believe that such disaggregation necessarily adds to the precision of the analysis. The analytical techniques that I have used – and that AUS uses – require density of data, that is, a large number of observations of additions and retirements. By disaggregating the accounts into subaccounts, the efficacy of these analyses is diminished, and the selection of life and survivor curve parameters becomes more subject to judgement, and at times guesswork.

Q. WHAT CHANGES HAS AUS RECOMMENDED IN THE DEPRECIATION PROCEDURES FOR GAS GENERAL AND COMMON PLANT?

A. AUS has proposed that general plant accounts which consist of many small units should be amortized rather than depreciated. Amortization reduces the Company's record keeping requirements by avoiding the need to maintain a record of the units placed each year by location so that they can be retired according to actuarial accounting procedures.

The amortization procedure does not use remaining life. In its simplest form, it uses the reciprocal of the estimated service life as the remaining life. A plant category with a 10-year life has a depreciation rate of 10 percent; one with a 20-year life is depreciated at five percent.

A number of these amortization accounts experience positive salvage, in which case the depreciation rate is calculated as follows:

$$\text{Depreciation Rate} = \frac{1 - \text{Salvage \%}}{\text{Service Life}}$$

Note, however, that it is still necessary to estimate the life of each plant account.

Q. WHAT PLANT LIVES DO YOU RECOMMEND FOR THE GAS GENERAL PLANT ACCOUNTS?

A. The SPR results for Account 390 – General Structures and Improvements indicate that AUS has overestimated the life of this account at 35 years. I recommend 30 years instead.

I have included computers with office furniture in a composite analysis of Account 391 because I do not have the separated data. Even if I did, I am not persuaded that the separation results in a more accurate picture of the overall life expectancy of this somewhat catchall account. I recognize, however, that computers have a relatively short service life, so I am willing to override the results of the SPR studies, all of which suggest approximately 30 years, and adopt the current 17 years as the amortization period for this account.

I have inadequate data for the following accounts:

		Current Life
392	Transportation Equipment	(no data)
393	Stores Equipment	39 Years
394.1	Tools, Shop and Garage Equipment	20 Years
394.3	Vehicle Maintenance Equipment	25 Years
394.4	Vehicle Refueling Equipment	(no data)
394.5	Laboratory Equipment	35 Years
396.1	Work Equipment	(no data)

I have maintained the current service life parameters for those accounts for which they are available. I have accepted AUS' recommendations for the remaining

accounts. For Account 292, AUS recommends 8 years for trailers and 6 years for cars and trucks. It recommends 15 years for Vehicle Refueling Equipment and 10 years for Work Equipment. All of these accounts are subject to amortization, so there is no need to select a survivor curve.

The SPR analyses support only 5-year life for Power Operated Equipment. This short life may explain the extraordinarily high positive salvage value of this equipment, discussed in the next section of this testimony.

I have performed an SPR analysis of all of account 397, Communications Equipment. It shows life indications of 30 to 40 years, well over any of the life estimates used by AUS for the five subaccounts into which it has divided this account. I am, however, familiar with telephone plant lives, and I acknowledge that this range of service lives is much too high given the changing technology of this equipment. For this reason I have accepted AUS' estimate of 15 years for Radio Equipment, and I have retained the current 15 years for General Telephone Equipment and 12 years for Supervisory and Telemetering Equipment. The SCADA equipment account is fully depreciated, but if any further equipment is added, it should be amortized under AUS' 8-year schedule. I recommend that network equipment be amortized on the same 15 year schedule as the bulk of this account.

Finally, I have accepted the 20 year life proposed by AUS for Account 398 – Miscellaneous Equipment.

Q. WHAT ARE YOUR LIFE AND SURVIVOR CURVE RECOMMENDATIONS FOR THE COMMON PLANT ACCOUNTS?

A. Most of the common plant accounts parallel the general gas plant accounts, and their service life expectations are much the same. There are, however, some differences.

The Common General Structures are more substantial than those of the Gas Division, and for this reason, I recommend accepting AUS' 35 year life which, if anything, may be too short.

My SPR analysis of Account 391 – Office Furniture and Equipment shows a much shorter service life than for the corresponding gas plant account. The consensus of the SPR results points to a 12-year life, which I recommend.

The SPR analysis of common Transportation Equipment indicates 14 years as the life of the composite account. This parameter is shorter than the life AUS recommends for trailers and longer than it recommends for cars and trucks.

NET SALVAGE RATIOS

Q. ASIDE FROM SERVICE LIVES AND SURVIVOR CURVES, WHAT ELSE ACCOUNTS FOR THE DIFFERENCES BETWEEN YOUR RECOMMENDED DEPRECIATION RATES AND THOSE PROPOSED BY AUS CONSULTANTS?

A. A major additional difference relates to our recommended net salvage ratios, and particularly the removal cost components of those ratios.

Q. **WHAT DO YOU MEAN BY THE "REMOVAL COST COMPONENT" OF NET SALVAGE?**

A. Removal costs refer to cost of removing, abandoning or dismantling property. When the cost of removal exceeds the revenues from salvage, as it does for the largest gas distribution accounts, the term applied is either "negative net salvage" or "net removal." Net removal ratios are conventionally shown as negatives; net salvage ratios as positive. Net removal costs are recovered by applying the ratio

to the amount of total plant that must be recovered over the service life of the plant removed. For example, if removal cost is five percent of the value of the plant to be removed, then the amount to be recovered is increased by five percent. That five percent factor is referred to as the "net removal cost ratio."

Q. WHAT NET REMOVAL COST RATIOS ARE MDU'S CONSULTANTS PROPOSING IN THIS CASE?

A. Table 4 shows the present net removal cost ratios and those proposed and those proposed by AUS, MDU's consultants.

Table 4
Net Removal (Negative Salvage) Ratios

Acct	Description	Present Ratio	Proposed Ratio
375	Distr. Structures & Improvements	-10%	-50%
376	Mains	-40%	-60%
378	Meas. & Reg Station Eqpt – General	0%	-30%
379	Meas. & Rg. Station Eqpt. – City Gate	0%	-15%
380	Services	-140%	-175%
385	Industrial Meas. & Reg. Eqpt.	+20%	-15%
390	Gas General Plant Structures	-5%	-10%
390	Common Plant General Structures	N/A	-10%
397.1	Common Radio Communications (Fixed)	N/A	-10%

Q. HOW DID AUS ARRIVE AT THESE RATIOS?

A. AUS followed a two-step process. First, they compared the original cost of the plant retired in each account each year since 1968 with the corresponding gross salvage and cost of removal to derive year-by-year positive gross salvage and negative cost of removal ratios. They did this on an annual basis and on a three year "rolling band" basis. Rolling bands means averaging three years starting with 1968-1970, then 1969-1971, then 1970-1972 up to 1999-2001. They then averaged the rolling bands for the entire 33 year period since 1968.

The second step involved two different operations. For gross salvage, AUS performed a standard linear trend analyses of the ratios for the past 5, 10, 15 and 20 years. For each account, they selected the ratio predicted by the final year of the five-year trend analysis. For the cost of removal ratio, they compounded an annual inflation factor of 2.75 percent for the number of years between the average age of retirements and the average service life. This compounding yielded a multiple which was then applied to the historical average removal cost ratio. The final net removal cost ratio is the sum of the gross salvage ratio and the cost of removal ratio.

Q. CAN YOU PROVIDE AN ILLUSTRATION OF THIS PROCEDURE?

A. Yes. Exhibit_____(CWK-6) is a copy of AUS' net salvage data and analysis for several of the MDU's larger gas distribution plant accounts. The exhibt covers accounts 375 – Distribution Structures and Improvements, 376 – Mains, and 380 – Services. There are two pages for each account. The first page is the raw data, which shows for each year since 1968 the original cost of the retirements, the gross salvage, the cost of removal, and the ratios to both salvage and removal cost to original cost.

The second page shows the three-year rolling bands, 1968-1970 through 1999-2001. At the bottom of that tabulation are the totals for the entire period and the average ratios. For Mains, the average positive salvage ratio is 3.12 percent, the average cost of removal ratio is -33.76 percent, and the average net salvage – 30.64 percent. For Services, the ratios are positive .33 percent for gross salvage, negative 134.29 percent for cost of removal, and negative 133.97 percent for net salvage.

AUS Consultants do not use these ratios. Instead, they extrapolate the last five years of positive salvage (1997-2001) out five years into the future. This means

that although gross salvage for Mains has averaged positive 3.12 percent since 1968, AUS uses a negative 2.72 percent ratio. This is because positive salvage was 31.08 percent in 1997 but only 0.41 percent in 1998 and zero since then. This trend indicates to AUS that in 2006, positive salvage will be negative 2.72 percent. The same condition applies to Services. Gross salvage has averaged positive .33 percent for the last 33 years, but AUS extrapolates a negative .07 percent gross salvage ratio for this account based on the trend since 1997.

AUS Consultants do not use the historical cost of removal ratios either. The historical cost of removal ratio for Mains is –33.76 percent. This number is inflated by a factor that reflects the expected inflation of 2.75 percent annually for the next 20 years, which is the difference between the average age of recent retirements and the average service life for the account. That inflation factor is 1.72. The cost of removal ratio used by AUS is 58.09 percent (33.76% x 1.75). For services, the same 1.72 inflation factor is applied to the historical removal cost ratio of 134.29 percent to yield an adjusted removal cost ratio of 231.04 percent.

The netting of these "adjusted" gross salvage and removal cost factors yields a net salvage factor of -60.81 percent for Mains and –231.11 percent of Services. AUS adopted the Mains factor rounded to –60 percent. Apparently, AUS found that negative 231 percent was too high for the Services account, so they recommended a negative salvage ratio of –175 percent.

Q. DOES AUS FOLLOW THE CONVENTIONAL PROCEDURE USED BY UTILITIES FOR CALCULATING NET SALVAGE RATIOS?

A. No. I have participated in dozens of utility depreciation cases, and this is the first time I have ever encountered the adjustments that AUS has applied to the historical gross salvage and removal cost ratios. Neither of these adjustments has any conceptual validity and both should be rejected.

A. AUS' cost of removal adjustment double-counts the effect of inflation. As I will discuss in more detail shortly, the historical ratios of removal costs to original plant cost already include the effect of inflation from the time the plant was installed to the time it was removed. According to AUS, the weighted average age of retired mains has been 25 years. This means that the average dollar of mains investment retired in 2001 was installed in 1976. That dollar reflects 1976 buying power, considerably more than the buying power of a dollar in 2001. The cost of removal in 2001, which is the numerator of the ratio, is expressed in 2001 dollars of considerably less value than the 1976 dollars of the original investment. As a result, cost of removal ratio already incorporates the historical inflation that occurred between 1976 and 2001. As I shall discuss, this inflation effect is the fundamental weaknesses of removal cost ratios as conventionally calculated by utilities.

AUS, however, further inflates the removal cost for yet more inflation. Their adjustment reflects the inflation between the age of recent retirements and the average service life of all units of plant.

Q. DO AUS CONSULTANTS OFFER ANY RATIONALE FOR THEIR ADJUSTMENTS TO THE GROSS SALVAGE AND REMOVAL COST RATIOS?

A. Yes. Page 3-10 of the AUS report contains the following statement:

> ...as property continues to age, gross salvage routinely declines, while with the passage of time cost of removal tends to increase in conjunction with ever increasing labor rates. On an aggregate basis, most historical retirements from each property group, routinely occur at an average age that is less than the average service life of the account. Accordingly, the experienced historical salvage analysis, with regard to gross salvage, will most often be overstated relative to anticipated future gross salvage. By comparison, the historical analysis will typically be understated with regard to future cost of removal. That is, in general terms, it can be assumed that with the increased passage of time, any

Q. WHY DOES THE GROSS SALVAGE ADJUSTMENT HAVE NO CONCEPTUAL VALIDITY?

A. A brief glance at the raw data for gross salvage on Exhibit_____(CWK-6) demonstrates the variability of gross salvage from year to year. I understand that this variability is in part because utilities do not necessarily sell their scrap material each year but sometimes allow it to accumulate before selling it in large lots. Whatever the reason, there is no particular significance to any one year's gross salvage, nor is there any significance to the trend over any given five years. There is certainly no significance to an extrapolation of the most recent five years into the future.

The utter absurdity of this extrapolation is demonstrated by the pages in Exhibit_____(CWK-6) that show the net salvage data for Account 375 – Distribution Structures and Improvements. In 1997, MDU realized $850 in gross salvage for retirements in this account, but has realized none since then. The second page of that account data reveals that AUS has extrapolated this "trend" to result in a negative -23.37 percent gross ratio. First of all, a negative gross salvage ratio is totally counter-intuitive. Over time, all gross salvage should be positive. More specifically, there has been no year in the past 33 when gross salvage for this account was ever negative, as demonstrated on the previous page,

The same observation applies to the Services account. Exhibit_____(CWK-6) reveals that there has never been a year when gross salvage for Services was negative, yet AUS has adopted a -.07 percent gross salvage ratio for the Service account.

Q. WHY DOES THE COST OF REMOVAL ADJUSTMENT HAVE NO VALIDITY?

future positive net salvage will likely be lower, while future negative net salvage will likely be higher than the overall levels experienced in the past.

Q. WHAT IS YOUR RESPONSE TO THIS RATIONALE?

A. This rationale fails on both empirical and conceptual grounds. Empirically, there is not a shred of evidence that over time, positive gross salvage ratios decline and negative removal cost ratios increase. The data in Exhibit_____(CWK-6) show that for Mains and Services, AUS' claimed trend arguably occurred between the beginning of the series, 1968, and the mid-1980s. Since then, however, the trends have generally been inconsistent, moving in the reverse direction for about 10 years, and then only in the past five years moving in the direction asserted by AUS.

The reason why there is no discernable trend in either the gross salvage or the removal cost ratios is that, contrary to AUS' assertion, the average age of retirements does not necessarily increase. It is true that the average age of retirements in any given year is less than the average service life of the entire plant category. This has to do with the fact that plant placed in a given year does not retire all at once. Rather, it retires in a dispersion over a number of years. The average service life is just that: an average. Some units retire sooner, some later than this average.

Given enough time, one might think that retirement the long-lived units would offset the effect of short-lived retirements, and the average age of retired units would trend toward the average service life. This would indeed happen if there were no growth in plant. But the reality is that each new vintage (year of placement) of plant tends to be larger than the previous vintage. Not only is the distribution system growing, but inflation is increasing the dollars required just to place the same amount of plant. As a result, there is always more new plant with its cohort of early retirements than there is old plant with long-lived retirements.

That is why the average age of retiring plant does not necessarily get longer. It is also why there are no discernable trends in gross salvage or cost of removal ratios.

Q. WHAT IS THE CONVENTIONAL PROCEDURE USED BY UTILITIES TO DEVELOP NET SALVAGE RATIOS?

A. Many utilities, although by no means all, use the unadjusted ratios developed by AUS. Those ratios reflect the relationship between the original cost of the plant retired and the gross salvage and cost of removal experience during the year of retirement. Because the booking of the retirements does not always match the booking of the salvage and removal cost, most utilities employing this procedure use "bands" of years such as the three-year rolling bands used by AUS.

Q. HOW WOULD THE NET SALVAGE RATIOS DEVELOPED UNDER THIS PROCEDURE COMPARE WITH THOSE PROPOSED BY AUS?

A. Exhibit_____(CWK-8) presents the net salvage ratios recommended by AUS and those that result from the conventional procedure. When conventional procedures are used, there are only four accounts for which negative salvage is justified, as follows:

Table 5

Net Salvage (Cost of Removal) Ratios
Distribution Plant

Acct	Description	Conventional	AUS
375	Distr. Structures & Improvements	-30%	-50%
376	Mains	-30%	-60%
378	Meas. & Reg Station Eqpt – General	-35%[4]	-30%
380	Services	-135%	-175%

Q. DO YOU RECOMMEND THESE RATIOS?

[4] Based on the past five years' experience

A. No. Although they are certainly better than the ratios recommended by AUS, these ratios are still severely overstated.

Q. WHY ARE THE RATIOS DERIVED BY THE CONVENTIONAL PROCEDURE OVERSTATED?

A. As I have already mentioned, even the conventional procedure for calculating net salvage ratios imputes the inflation experienced between the time of a unit's replacement and the time of its removal. The numerator of the removal cost ratio is expressed in recent dollars, while the denominator is expressed in dollars from many years ago. The value of the dollars in the numerator is much greater than that in the denominator, so that the fraction (i.e. ratio) is overstated.

Q. CAN YOU PROVIDE SPECIFIC EXAMPLES OF THIS CONDITION?

A. Yes. Consider the example of mains retired in the year 2001. Page 1 of Exhibit_____(CWK-6) shows that the original cost of the mains retired in 2001 was $171,124 and that the cost of their removal was $74,110. The conventional treatment is to compare these two dollar amounts, yielding a removal cost ratio of –43.31 percent.

According to AUS, the average age of retiring mains is 25 years, meaning that the average main retired in 2001 was placed in 1976.[5] The Handy-Whitman construction price index for steel mains in the North Central Region was 147 in 1963; in 2001 it was 382.[6] Expressed in 2001 dollars, the $174,124 of original cost of mains retired in that year would be $452,486 ($174,124 x (382/147)). If the removal cost and original cost were expressed in comparable dollars, the

[5] AUS Report, page 8-6.
[6] *Handy-Whitman Index of Public Utility Construction Costs*, Whitman, Requardt and Associates, Bulletin No. 156, 2002.

removal cost ratio would be -16.4 percent ($74,110/$452,486), not –43.31 percent.

The same condition applies to services. The original cost of the services retired in 2001 was $123,831; their removal during that year cost $203,229. The conventional removal cost ratio of these two numbers is –164 percent. AUS indicates that the average retirement age of a service is 20 years, meaning that the average service retired in 2001 was placed in 1981. The Handy-Whitman index for plastic services in 1981 was 185; in 2001 it was 374. Expressed in 2001 dollars, the services retired in 2001 were worth $250,339 ($123,831 x (374/185)), yielding a removal cost ratio, expressed in consistent dollars, of -81 percent, less than half the ratio under the conventional procedure.

Q. WHAT IS WRONG WITH THE CONVENTIONAL PROCEDURE?

A. There are two things wrong with it. First, it requires ratepayers to pay for future inflation in current dollars. This might not be a problem if the ratios developed according to the conventional procedure were applied only to currently retiring plant for purposes of developing depreciation rates. But they are not. They are applied to <u>all</u> plant, including that which was placed just last year. As a result, current ratepayers are obliged to pay for future inflation stretching out over the remaining life of the plant they use.

The second objection is that this procedure fails totally to recognize the present value of cash payments. It is generally accepted in financial, accounting and economic analysis that a dollar paid today is worth more than a dollar paid next year. A dollar owed ten years from now is worth much less than a dollar paid next year. That is because whoever possess the dollar in the meantime can invest it and earn a return during the intervening nine years. Alternatively, he can spend the dollar next year and enjoy the goods or services that it buys until he has to pay the dollar back ten years from now.

The conventional procedure for recapturing removal costs makes no distinction between dollars paid by ratepayers in the current year and dollars spent to remove plant many years from now. For purposes of charging depreciation, they are all of equal value.

Q. BUT DON'T RATEPAYERS RECEIVE THE BENEFIT OF THE RATE BASE DEDUCTION REPRESENTED BY THE ACCRUAL OF THESE RETIREMENT COST ALLOWANCES?

A. No. An argument might be made that inflated depreciation charges build up the depreciation reserve, which in turn reduces the net investment rate base. The reduced rate base lowers the requirement for return and income taxes. Over time, one might think this reduction should cancel out the increase in revenue requirement represented by the excessive depreciation expenses.

Only it doesn't. That is because the dollar value of the Company's plant is always expanding. The Company is growing, but even if it were not, inflation causes the dollars added each year to exceed the dollars retired. There is always more new plant generating higher depreciation charges than old plant that has accumulated depreciation reserve. Ratepayers never catch up.

Q. IS THERE AN ACCOUNTING PROCEDURE THAT RESOLVES THESE PROBLEMS YOU HAVE IDENTIFIED WITH RESPECT TO REMOVAL COST RATIOS?

A. Yes. The Financial Accounting Standards Board has recently published an accounting procedure for dealing with the retirement costs of long-lived assets that must be removed by reason of legal obligations. These procedures were published in 2000 in Statement of Financial Account Standards No. 143 ("SFAS

143"). A summary of that statement is attached to this testimony as Exhibit____(CWK-7)

Q PLEASE DESCRIBE SFAS 143.

A. As I have just noted, SFAS 143 addresses long-lived assets for which there are legal obligations to incur retirement costs. A legal obligation is defined as "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel." A good example of such an obligation is the requirement to dismantle, entomb or decontaminate a nuclear generating plant.

When a company finds that it has a legal obligation that fits this description, it must declare the retirement cost as a liability on its balance sheet. That liability is not the ultimate cost of the retirement, but the present value of that cost, using as the discount factor the risk-free interest rate when the liability was recognized.

The annual expense associated with this liability consists of two parts. One is the amortization of the liability, which is the present value of the liability divided by the life of the asset – comparable to depreciation. The second expense is the annual accretion in the present value of the liability.

Q. CAN YOU ILLUSTRATE HOW THIS PROCEDURE WORKS?

A. Assume that MDU installs a gas manufacturing facility that it expects to last for 40 years. It is obligated to dismantle that plant when it retires at an estimated cost of $1 million. MDU would book a liability for this retirement cost, not at $1 million, but at $1 million discounted at the risk-free interest rate. The risk free

interest rate over 40 years is 7 percent.[78] The liability would therefore be booked as $69,118 ($1 mil/1.07^{40})

Each year, MDU would show two items of expense. The first would be the amortization of the liability. In the first year after installation that would be $69,118/ 40 years = $1,728. This item would increase each year as the present value of the liability increases. The second expense would be the annual accretion in the liability itself. In this instance, it would be $1 million times 1.07^{39} - 1.07^{40}. This is $1 million x (0.07395- 0.06911=.00484) or $4,840. As the present value factors increase, that is, as they approach 1.0, this annual amount would also increase. Total expense in the first year of operation would be $1,728 + $4,840 = 6,568.

Q. HOW DOES THE SFAS 143 PROCEDURE RESOLVE THE PROBLEMS YOU HAVE IDENTIFIED WITH THE CONVENTIONAL PROCDURE FOR CALCULATING AND APPLYING NEGATIVE SALVAGE RATIOS?

A. Unlike the conventional procedure for calculating and applying negative salvage, the SFAS 143 procedure recognizes the present value of future costs. It therefore resolves the unfairness of charging present ratepayers with an inflated cost that the Company will not incur until many years from now.

Q DO YOU THEREFORE RECOMMEND THAT THE SFAS 143 PROCEDURE BE APPLIED TO MDU'S RETIREMENT COSTS IN THIS CASE?

A. Yes, but I do not recommend this procedure as the ultimate solution to the problem of gas plant retirement costs. That is because the SFAS procedure still

[7] Seven percent is the rate that MDU is using as its discount factor for the SFAS 143 obligations at its Coyote Station and Big Stone electric generation plants.

requires a forecast of the final, inflated value of future retirement costs. As I will discuss later in this testimony, there are procedures available that avoid this necessity.

Q. HAVE YOU APPLIED THE SFAS 143 PROCEDURE THE RETIREMENT COSTS OF MDU'S GAS DISTRIBUTION PLANT?

A. Yes. That application is presented in Exhibit_____(CWK-9). Page 1 of that exhibit presents the discount factors at seven percent. For this purpose, I use a half-year convention, that is, the average of the discount factor at the beginning and end of each year.

Page 2 of Exhibit_____(CWK-9) develops the negative net salvage ratios reflecting the SFAS 143 discounting procedure. The top line presents the conventional negative salvage ratios. The next three lines reduce those ratios to their discounted present value as of the end of the remaining life of the plant. Line 5 presents the present value increment between the remaining life year and the following year that SFAS 143 requires. The remaining lines calculate the depreciation rate with and without retirement costs included. Line 17 shows the discounted present value of the retirement costs expressed over the entire remaining life of the plant. Finally, line 18 develops the negative salvage ratio reflective of the SFAS 143 procedure. Those ratios are replicated in summary Exhibit_____(CWK-8).

Q. WHAT NET SALVAGE RATIOS ARE YOU RECOMMENDING IN THIS CASE?

A. My recommended net salvage ratios are presented in the final column of Exhibit_____(CWK-8). I have adopted the negative salvage ratios developed in Exhibit_____(CWK-9). With two exceptions, I have adopted the positive salvage

[8] Federalreserve.gov/releases/H15 20 year Treasury bonds, Dec 2002.

ratio developed by the conventional method of comparing actual positive salvage with the value of experienced retirements. The two exceptions are Account 396.2 – Power Operated Equipment for both gas and common plant, where I question the very high levels of gross salvage. In the case of gas equipment, I have adopted the AUS ratio. In the case of common equipment, I recommend a ratio half way between the conventionally derived ratio and that recommended by AUS.

Q. EARLIER, YOU SUGGESTED THAT THERE ARE OTHER METHODS OF TREATING RETIREMENT COSTS THAT DO NOT REQUIRE FORECASTING COSTS INTO THE FUTURE. WHAT ARE THEY?

A. There are two methods of treating retirement costs that avoid the necessity of predicting costs that will not be incurred for years, sometimes decades into the future. The first is to capitalize the retirement costs of plant that is being replaced as part of the cost of the replacement plant. MDU reports that 94 percent of its retiring mains are replaced *in situ* or with parallel pipes and 73 percent of its services are similarly replaced. There are only two reasons for replacing a main or a service. Either the previous pipe has become physically deteriorated or it has inadequate capacity to handle current or forecast loads. In either case, the inadequacies of the old pipe are the cause of the new pipe, so it is not inappropriate to consider that the cost of retirement is a component of the cost of the replacement plant. This procedure avoids the need to predict future inflation, and it ensures that the Company will recover all of its retirement costs, no more and no less.

In the absence of replacement – only 6 percent of mains and 27 percent of services – the appropriate treatment is to develop removal cost allowances within the depreciation rates that reflect recent experience, say, the average of the most recent five years. This treatment is similar to expensing except for two important considerations. First, it does not reflect any given year's activity. As can be seen

from the data in Exhibit_____(CWK-6), removal costs vary from year to year. Second, this procedure retains the tie to depreciation, so that as the plant grows, the removal cost allowance grows correspondingly. Again, it ensure that the Company recovers its removal costs, no more and no less.

The combination of these two procedures would remove altogether the need to predict future removal costs. Because the overwhelming portion of removal costs would be recovered through capitalization in replacement plant, these procedures would not unduly subvert the basic purpose of depreciation rates, which is to recover past investment in a fair, reasonable and systematic manner. I submit that the present procedures for treating removal costs have resulted in just that subversion.

Q ARE THERE ANY REGULATORY PRECEDENTS FOR THE PROCEDURES YOU ARE PROPOSING?

Yes. The practice of incorporating retirement costs into the capital cost of the replacement plant is explicitly recognized in FERC's Uniform System of Accounts ("USOA"). Paragraph 31 of the Electric USOA (Subchapter C) and paragraph 32 of the gas USOA (Subchapter F) contain the following definition:

> *Replacing or replacement*, when not otherwise indicated in the context, means the construction or installation of electric (gas) plant in place of property retired, together with the removal of the property retired. [Emphasis supplied]

Paragraph 10 of both the electric and gas plant instructions covers additions and retirements of plant. It refers to "...additions to and retirements and replacements of electric (gas) plant..." It goes on to provide instructions for the recording of retirement unit additions and retirements. If the definition of replacements provided above applies, then the addition of a replacement unit should include the cost of removing the property retired.

The practice of allowing only current retirement costs to be charged to ratepayers is universally applied to all utilities in Pennsylvania. It is also used by utilities in Missouri, Kentucky and Georgia, including Georgia Power and Atlanta Gas Light Company.

Q. WHY HAVE YOU PROPOSED THE SFAS 143 PROCEDURE IN THIS CASE IF YOU BELIEVE THAT ULTIMATELY, THERE ARE BETTER METHODS FOR DEALING WITH RETIREMENT COSTS?

A. This Commission has approved the remaining life procedure, which develops depreciation rates based on the recovery of the remaining undepreciated plant over the remaining life of each account. Currently MDU has built up very large depreciation reserves not only as a result of having collected future retirement costs, but as a consequence of having used too short service lives in its past depreciation.

The immediate implementation of the practices that I am recommending as the ultimate resolution of the removal cost issue would result in extremely low depreciation rates, much lower than those I have proposed in this testimony. As it is, I have proposed to reduce MDU's gas distribution plant depreciation almost half. Further reductions resulting from a "flash cut" to these ultimate procedures might so reduce the internal cash generation within the Company as to impair its ability to replace plant and expand its system as demand requires.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Charles W. King

Attachment A

Experience

Snavely King Majoros O'Connor & Lee, Inc.
Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, earnings and depreciation. Mr. King recently directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

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Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AK	Exxon USA	P-89-1,2	Trans Alaska Pipeline System	October 18, 1990
AZ	Arizona Corporation Commission Arizona Retailers Association	U-1345-I U-1345-II	Arizona Public Service Co. Arizona Public Service Co.	December 16, 1980 January 15, 1981
CA	California Retailers Association California Retailers Association California Retailers Association California Retailers & California Manufacturers California Retailers Association	57666 57602 59351 59351 61138	Pacific Gas & Electric Co. Southern California Edison Pacific Gas & Electric Co. Southern California Edison Southern California Edison	March 6, 1978 April 25, 1978 June 12, 1981 May 20, 1982 May 28, 1982
CO	U. S. Department of Defense J.C. Penny Company U.S. Department of Defense U. S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense	I&S 1100 5693 I&S 1339 I&S 1540 C. Council C. Council C. Council C. Council	Colorado Springs (Elec) All Electric Utilities Colorado Springs DPU (Gas) Colorado Springs DPU (Gas) Colorado Springs DPU (Gas) Colorado Springs DPU (Elec) Colorado Springs DPU (Elec) Colorado Springs DPU (Elec)	June 14, 1977 March 8, 1978 October 18, 1979 February 9, 1982 September 30, 1984 June 6, 1985 May 19, 1986 June 30, 1987
CT	Retailers Merchants Association Division of Consumer Counsel Public Utilities Control Auto Division of Consumer Counsel Division of Consumer Counsel Division of Consumer Counsel Division of Consumer Counsel Coalition of Hotels, Alloys & Retailers Coalition of Hotels, Alloys & Retailers	72-0204 76-0604,5 78-0303 80-0403,4 81-0413 81-0602,4 82-0701 85-10-22 87-07-01	Various Electric Utilities CL&P and HELCO Bridgeport Hydraulic Co. CL&P and HELCO United Illuminating Company CL&P and HELCO CL&P CL&P CL&P	July 22, 1976 November 10, 1977 (none) August 11, 1980 July 20, 1981 October 5, 1981 September 28, 1982 (none) April 25, 1988

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
DC	D.C. People's Counsel	685	Potomac Electric Power Company	March 6, 1978
	D.C. People's Counsel	715	Potomac Electric Power Company	(none)
	D.C. People's Counsel	725	Potomac Electric Power Company	April 4, 1980
	D.C. People's Counsel	737	Potomac Electric Power Company	January 1, 1981
	Washington Metro Area Transit Authority	748	Potomac Electric Power Company	June 26, 1981
	Washington Metro Area Transit Authority	758	Potomac Electric Power Company	December 15, 1981
	D.C. People's Counsel	785	Potomac Electric Power Company	September 21, 1982
	Washington Metro Area Transit Authority	759	Potomac Electric Power Company	March 29, 1984
	D.C. People's Counsel	685 Remand	Potomac Electric Power Company	June 10, 1985
	D.C. People's Counsel	905	Potomac Electric Power Company	August 20, 1991
	D.C. People's Counsel	912	Potomac Electric Power Company	May 7, 1992
	D.C. People's Counsel	834, III	Potomac Electric Power Company	May 22, 1992
	D.C. People's Counsel	917	Potomac Electric Power Company	September 24, 1992
	D.C. People's Counsel	922	Washington Gas Light Company	June 15, 1993
	D.C. People's Counsel	929	Potomac Electric Power Company	December 16, 1993
	D.C. People's Counsel	934	Washington Gas Light Company	Filed April 22, 1994
	D.C. People's Counsel	939	Potomac Electric Power Company	March 16, 1995
	D.C. People's Counsel	917	Potomac Electric Power Company	April 16, 1995
	D.C. People's Counsel	951	Potomac Electric Power Company	February 20, 1997
	D.C. People's Counsel	945	Potomac Electric Power Company	September 29, 1999
	D.C. People's Counsel	847	Washington Gas Light Company	June 27, 2001
DE	DPSC Staff	94-164	Artesian Water Company	(none)
	DPSC Staff	94-149	Wilmington Surburban Water Company	March 10, 1995
FL	Florida Retail Federation	790593-EU	All Electric Utilities	March 5, 1981
	Florida Retail Federation	810002-EU	Florida Power and Light Company	July 23, 1981
	Florida Retail Federation	820097-EU	Florida Power and Light Company	September 22, 1982
	Florida Retail Federation	820097-EU	Florida Power and Light Company	April 11, 1983
	Florida Retail Federation	830012-EU	Tampa Electric Company	August 19, 1983
	Florida Retail Federation	830465-EI	Florida Power and Light Company	April 19, 1984
	Florida Retail Federation	830465-EI	Tampa Electric Company	(none)
GA	Georgia Retail Federation	3270-U	Georgia Power Company	September 3, 1981
	Georgia Public Service Commission	4007-U	Georgia Power Company	August 21, 1991
	Georgia Public Service Commission	4384-U	All Electric Utilities	August 1, 1993
	Georgia Public Service Commission	4755-U	Georgia Power Company	January 25, 1994
	Georgia Public Service Commission	4697-U	All Utilities	May 10, 1994
	Georgia Public Service Commission	9355-U	Georgia Power Company	November 4, 1998
HI	Public Utilities Department	2793	All Electric Utilities	February 14, 1978
	Hawaii Consumer Advocate	4536	Hawaiian Electric Company	February 1, 1983

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
IL	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	76-0698	Commonwealth Edison	June 22, 1977
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	76-0568	All Eletric Utilities	(none)
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	80-0546	Commonwealth Edison	March 5, 1981
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	82-0026	Commonwealth Edison	July 22, 1982
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	83-0537	Commonwealth Edison	March 19, 1984
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	87-0427	Commonwealth Edison	March/April 22, 1988
	Illinois Retail Merchants Association/	90-0169	Commonwealth Edison	October 29, 1990
IN	Indiana Retail Council	35780-S2	N. Ind. Public Service co.	June 1, 1980
	Indiana Retail Council	35780-S1	Public Service of Indiana	October 15, 1980
	Indiana Retail Council	36318	Public Service of Indiana	May 4, 1982
KS	J.C. Penny Company	115,379-U	All Kansas Utilities	January 22, 1981
KY	Seven Kentucky Retailers	7310	Louisville Gas & Electric Co.	April 25, 1979
	Kentucky Cable Telecommunications Assn.	2000-414	Blue Grass Energy Cooperative	January 11, 2001
	Kentucky Cable Telecommunications Assn.	2000-39	Cumberlant Valley Electric, Inc.	January 11, 2001
MA	Coalition of Municipalities	20279	Western Massachusetts Electric	March 19, 1980
	Coalition of Municipalities	557/558	Western Massachusetts Electric	May 14, 1981
	Coalition of Municipalities	957	Western Massachusetts Electric	March 9, 1982
	Coalition of Municipalities	1300	Western Massachusetts Electric	January 1, 1983
	Coalition of Municipalities	85-270	Western Massachusetts Electric	March 26, 1986
MD	Maryland People's Counsel	6977	Washington Gas & Light Company	September 17, 1976
	Maryland People's Counsel	6814	Potomac Electric Power Company	
	Maryland People's Counsel	6807	All Electric Utilities	September 1, 1977

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
MD	Maryland People's Counsel	6882	Baltimore Gas & Electric Company	(none)
	Maryland People's Counsel	6985	Baltimore Gas & Electric Company	September 28, 1976
	Maryland People's Counsel	7070	Baltimore Gas & Electric Company	December 20, 1976
	Maryland People's Counsel	7149	Potomac Electric Power Company	April 18, 1978
	Maryland People's Counsel	7163	All Electric Utilities	January 17, 1979
	Maryland People's Counsel	7236	Delmarva Power & Light Company	October 23, 1978
	Retail Merchants of Baltimore	7397	Baltimore Gas & Electric Company	June 20, 1980
	Maryland People's Counsel	7427	Delmarva Power & Light Company	September 8, 1980
	Maryland People's Counsel	7574	Baltimore Gas & Electric Company	December 2, 1981
	Maryland People's Counsel	7597	Potomac Electric Power Company	February 18, 1982
	Organization of Consumer Justice	7604	Potomac Electric Power Company	April 20, 1982
	Maryland People's Counsel	7588	Baltimore Gas & Electric Company	October 19, 1982
	Maryland People's Counsel	7663	Potomac Electric Power Company	November 22, 1982
	Retail Merchants of Baltimore	7685	Baltimore Gas & Electric Company	April 12, 1983
	Genstar Stone Products, et al.	7878	Potomac Electric Power Company	December 9, 1985
	Industrial Intervenors	7878	Potomac Electric Power Company	June 28/July 1986
	Maryland People's Counsel	7983	Baltimore Gas & Electric Company	March 4, 1987
MI	General Services Administration	U-10102	Detroit Edison Company	March 22, 1993
	Michigan Attorney General	U-11722	Detroit Edison Company	November 6, 1998
	Michigan Attorney General	U-11772	Consumers Energy/Detroit Edison	November 16, 1998
	Michigan Attorney General	U-11495	Detroit Edison Company	December 8, 1999
	Michigan Attorney General	U-11956	Consumer Energy/Detroit Edison	December 15, 1999
	Michigan Attorney General	U-12505	Consumers Energy Company	September 7, 2000
	Michigan Attorney General	U-12478	Detroit Edison Company	October 5, 2000
	Michigan Attorney General	U-12639	Consumers Energy/Detroit Edison	July 18, 2001
	Michigan Attorney General	U-13000	Consumers Energy Company	January 29,2002
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975
ND	North Dakota Public Service Commission	PU-400-00-521	Xcel Energy, Inc.	April 20, 2001
	North Dakota Public Service Commission	PU-399-01-786	Monatan-Dakota Utilities	February 25, 2002
NH	Business & Industry Association of N.H.	79-187-II	Public Service of N.H.	February 6, 1981
	Business & Industry Association of N.H.	80-260	Public Service of N.H.	February 5, 1981
	Business & Industry Association of N.H.	82-333	Public Service of N.H.	November 2, 1983

State	Electric, Gas, Water Utility Cases			
	Client	Case		Date of Cross-Examination
		Case Number	Utlilty	
NJ	Dept. of Public Advocate	761-8	Public Service Electric & Gas	January 18, 1977
	Dept. of Public Advocate	7911-951	Atlantic City Electric Co.	April 21, 1980
	N.J. Retail Merchants Association	803-151	All New Jersey Utilities	March 31, 1981
	Department of Public Advocate	815-459	N.J. Natural Gas Company	(none)
	Resorts International Hotel, Inc.	8011-827	Atlantic City Sewerage Co.	(none)
	Dept. of Public Advocate	822-116	Atlantic City Electric Co.	August 11, 1982
	Dept. of Public Advocate	355-87	Elizabethtown Gas	June 9, 1987
	Dover Township Fire Chiefs	88-080967	Tom's River Water Company	February 22, 1989
NY	N.Y. Council of Retail Merchants	26806	All Electric Utilities	February 3, 1976
	Metropolitan N.Y. Retail Council	27029	Consolidated Edison Company	(none)
	Metropolitan N.Y. Retail Council	27136	Long Island Lighting Company	July 1, 1977
	N.Y. Metro. Transit Authority	27353	Consolidated Edison Company	September 5, 1980
OH	Ohio Council of Retail Association	88-170-EL	Cleveland Elec. Illuminating	(none)
	Ohio Council of Retail Association	83-1529-EL	Cincinnati Gas & Electric	February 15, 1992
PA	Pennsylvania Retail Association	76-PRMD-7	All Electric Utilities	September 7, 1977
	Southeastern Pa. Transp. Authority	R-811626	Philadelphia Electric Company	December 11, 1981
	Eastern Penn Energy Users Group	R-822169	Penn. Power & Light Company	March/April 1983
	Eastern Penn Energy Association	R-842651	Penn. Power & Light Company	December 3, 1984
	Penn Business Utility User Group	R-850152	Philadelphia Electric Company	February 19, 1986
	Pennsylvania Office of Consumer Advocate	R-00016339	Pennsylvania-American Water Co.	September 19, 2001
TX	Houston Retailers Association	5779	Houston Lighting Company	October 19, 1984
	Houston Retailers Association	6765	Houston Lighting Company	September 25, 1986
	Cities for Fair Utility Rates	8425/8431	Houston Lighting Company	April 25, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
UT	Div. Of Public Utilities Dept of Commerce	98-2035-33	Pacific Corp	Filed August 16, Sept 22, 1999
VA	Consumer Congress of Virginia Consumer Congress of Virginia Va. Business Committee on Energy Virginia Pipe Trades Council	19426 19960 PUE 7900012 PUE 8900051	Virginia Electric Power Company Virginia Electric Power Company Virginia Electric Power Company Old Dominion Electric Corp. &	July 1, 1975 September 19, 1978 February 25, 1981 October 31, 1989
WI	Wisconsin Merchants Federation	6630-ER-2	Wisconsin Electric Power Company	May 15, 1978

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
AL	U.S. Department of Defense	24472	All Telephone Companies	June 14, 1995
AZ	Arizona Burglar & Fire Alarm Association	9981-E-1051-80-64	Mountain State Telephone	(none)
	Federal Executive Agencies	E-1051-88-146	Mountain State Telephone	(none)
	U.S. Department of Defense	T-01051B-99-0105	US WEST Communications	Filed July 26, Sept 8, 2000
CA	Western Burglar & Fire Alarm Association	59849	Pacific Telephone & Telegraph	March 25, 1981
	Western Burglar & Fire Alarm Association	5984cont.	Pacific Telephone & Telegraph	June 23, 1982
	Western Burglar & Fire Alarm Association	A83-01-22	Pacific Telephone & Telegraph	June 29, 1983
	Western Burglar & Fire Alarm Association	A83-02-02	General Telephone of California	January 17, 1984
	Western Burglar & Fire Alarm Association	A82-11-07	Pacific Telephone & Telegraph	Jan. 18, Oct. 31 November 28, 1984
	Western Burglar & Fire Alarm Association	A85-01-034	Pacific Telephone & Telegraph	June 4, 1985 October 2, 1986
	Western Burglar & Fire Alarm Association	A87-01-02	General Telephone of California	October 22, 1987
	Western Burglar & Fire Alarm Association	A88-07-17019	Pac. Bell Tel. & GTE of CA.	January 23, 1989
	California Cellular Resellers	A.88-11-1040	All Cellular Carriers	August 11, 1989
	Federal Executive Agencies	1.87-11-033	All Telephone Companies	March 6-7, 1991
	California Cellular Resellers	1.88-11-040	All Cellular Carriers	August 19, 1991
	Cellular Services, Inc.	1.88-11-040	All Cellular Carriers	October 3, 1991
	Federal Executive Agencies	A92-05-004	Pacific Telephone & Telegraph	June 9, 1993
CO	U.S. Department of Defense	I&S 717	Mountain Bell Telephone Company	1972
	U.S. Department of Defense	I&S 1700	Mountain Bell Telephone Company	(none)
	U.S. Department of Defense	Appl.	Mountain Bell Telephone Company	September 18, 1986
	U.S. Department of Defense	I&S 1766	Mountain Bell Telephone Company	November 28, 1988
	Colorado Municipal League	Appl 36883	Mountain Bell Telephone Company	December 13, 1988
	U.S. Department of Defense	I&S 891-O82T	U.S. West Communications	February 21, 1990
	U.S. Department of Defense	905-544T	U.S. West Communications	July 17, 1991
	U.S. Department of Defense	90A-665T	U.S. West Communications	October 23, 1991
	U.S. Department of Defense	92M-039T	U.S. West Communications	February 24-24, 1992
	U.S. Department of Defense	92S-229T	U.S. West Communications	July 30-31, 1992
	U.S. Department of Defense	90A-665T	U.S. West Communications	November 6, 1996
	AT&T	96S-331T	U.S. West Communications	April 17, 1997

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
CT	Connecticut Consumer Counsel	770526	Southern New England Telephone Co	November 10, 1977
	CT Cellular Resellers Assn.	89-12-05	Southern New England Telephone Co	(none)
	CT Cellular Resellers Coalition	94-03-27	Springwich Cellular/Bell Atlantic	May 16, June, 1994
	AT&T	AT&T/SNET Arbitration	Southern New England Telephone Co	Filed October 28, 1996
	Connecticut Consumer Counsel	96-04-07	Southern New England Telephone Co	February 10,1998
	Connecticut Consumer Counsel	00-07-17	Southern New England Telephone Co	December 5, 2000
DC	D.C. People's Counsel	729	Chesapeake & Potomac Tel. Co.	May 13, 1980
	D.C. People's Counsel	798	Chesapeake & Potomac Tel. Co.	July 18, 1983
	General Services Administration	827	Chesapeake & Potomac Tel. Co.	May 7, 1985
	General Services Administration	854	Chesapeake & Potomac Tel. Co.	April 16, 1987
	General Services Administration	850	Chesapeake & Potomac Tel. Co.	October 7, 1991
	General Services Administration	926	Chesapeake & Potomac Tel. Co.	October 7, 1993
DE	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	April 1, 1985
	Federal Executive Agencies	86-20	Diamond State Telephone Co.	July 31, 1987
	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	March 8, 1988
FL	GTE Sprint Communications Company	720536-TP	All Telephone Companies	September 12, 1983
	Office of Public Counsel	Depr.Repre	Southern Bell	July 30, 1986
	Federal Executive Agencies	880069-TL	Southern Bell	July 21, 1988
	Federal Executive Agencies	880069-TL	Southern Bell	November 30, 1990
	Federal Executive Agencies	880069-TL	Southern Bell	February 11, 1992
GA	Georgia Attorney General	3893-U	Southern Bell Telephone Co.	January 8, 1990
	Federal Executive Agencies	3905-U	Southern Bell Telephone Co.	June 12, 1990
	Federal Executive Agencies	3987-U	Southern Bell Telephone Co.	February 13, 1992
	Georgia Public Service Commission	4018-U	Southern Bell Telephone Co.	Jan 14, Feb 10, 1993
HI	Hawaii Public Utility Commission	1871	Hawaiian Telephone Company	July 8, 1971
	Four Hawaii Counties	4588	Hawaiian Telephone Company	December 15, 1983
	Department of Defense	7579	Hawaiian Telephone Company	April 26, 1994
	Department of Defense	94-0093	Oceanic Communications	March 13, 1995
	Department of Defense	7702	All Communications Carriers	June 2, 1995
	Department of Defense	94-0298	GTE Hawaiian Telephone Company	May 7, 1996
	Department of Defense	7720	Verizon-Hawaii	November 15, 2000

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
ID	U.S. Department of Energy U.S. Department of Energy	U-1000-63 U-1000-70	Mountain Bell Telephone Co. Mountain Bell Telephone Co.	May 16, 1983 March 6, 1984
IL	Illinois Aalarm Companies Attorney Generaal of Illinois GTE Sprint Communications Co. Federal Executive Agencies	79-0143 81-0478 83-0142 89-0033	Illinois Bell Telephone Illinois Bell Telephone All Telephone Companies Illinois Bell Telephone	September 26, 1979 December 28, 1981 August 4, 1983 June 12, 1989
KS	State Corporation Commission Federal Executive Agencies Federal Executive Agencies	Depr. Repr. 166.856-U 190, 492	Southwestern Bell Southwestern Bell All Telephone Companies	May 12-14, 1986 November 7, 1989 November 4, 1994
MD	Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Federal Executive Agencies Federal Executive Agencies Federal Executive Agencies	6813 6881 7025 7467 7851 8106 8274	C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company	1975 December 17, 1975 March 15, 1975 October 20, 1981 March 20, 1985 May 9, 1988 August 2, 1990
MI	Michigan Attorney General Michigan Attorney General	U-8911 U-9553	Michigan Bell Telephone Co. AT&T Communications/MCI	November 7, 1988 December 4, 1990
MN	GTE Sprint Communications Co. U.S. Department of Defense	83-102-HC 87-021-BC	All Telephone Companies Northwest Bell Telephone Co.	August 5, 1983 (none)
MO	GTE Sprint Communications Co. Federal Executive Agencies Federal Executive Agencies	TR83-253 TC-89-14 TO-89-56	Southwestern Bell Tel. Co. Southwestern Bell Tel. Co. Southwestern Bell Tel. Co.	September 5, 1983 (none) November 7, 1990
MS	Federal Executive Agencies	U-5453	South Central Bell Tel. Co.	May 15, 1990

Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
NJ	Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate	Depr.Repr. 815-458 Depr.Repr. Depr.Repr. T092030358	N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company	Mar-79 October 15, 1981 March 1, 1982 February 1, 1985 September 30, 1992
NM	New Mexico Corporation Commission New Mexico Corporation Commission	1032 86-151-TC	Mountain Bell Telephone Co. General Telephone of Southwest	November 14, 1983 February 5, 1987
NV	Prime Cable of Las Vegas Prime Cable of Las Vegas	95-8034/8035 96-9035	Central Telephone - NV Sprint/Centel, Nevada Bell	Filed November 22, 1995 June 2, 1997
NY	Holmes Protection, Inc. Holmes Protection, Inc. 5 Alarm Companies GTE Sprint Communications Co.	27350 27469 27710 28425	New York Telephone Company New York Telephone Company New York Telephone Company All Telephone Companies	October 17, 1978 May 17, 1979 July 24, 1980 July 8, 1983
PA	City of Philadelphia	R-832316	Pennsylvania Bell Telephone	September 20, 1983
SC	Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate	Depr.Repr. 86-511-C 86-541-C Depr.Repr. 89-180-C	Southern Bell Southern Bell General Telephone of South Southern Bell ALLTEL of South Carolina	July 1, 1986 December 11, 1986 April 8, 1987 July 10, 1989 September 26, 1989
TX	U.S. Department of Defense	8585/8218	Southwestern Bell Telephone Co.	(none)
VA	U.S. Dept. Of Defense, GSA, et Federal Executive Agencies	19696 PUC 890014	C&P Telephone Company All Telephone Companies	October 6, 1976 February 13, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
VI	V.I. Department of Commerce	205	Virgin Islands Telephone Co.	April 29, 1980
	V.I. Public Service Commission	341	Virgin Islands Telephone Co.	March 20, 1991
WA	U.S. Department of Defense	U-72-39	Pacific Northwest Bell	1973
	U.S. Department of Defense	U-87-796-T	Pacific Northwest Bell	December 20, 1983
	U.S. Department of Defense	U-88-20524	Pacific Northwest Bell	November 8, 1988
	U.S. Department of Defense	U-89-2698-F	US West Communications	November 28, 1989
	WA Attorney General/TRACER	UT-940641	US West Communications	Filed October 14, 1994
	U.S. Department of Defense	UT-941464	US West Communications	June 22, 1995
	U.S. Department of Defense		US West Communications	January 22, 1996
	WA Attorney General/TRACER	UT-951425	US West Communications	Filed June 23, 1997
	WA Attorney General/TRACER	UT-961632	GTE Northwest, Inc	July 29, 1997
WI	GTE Sprint	6720-TR-38	All Telephone Companies	October 20, 1983

Client	Docket	Subject	Date of Cross-Examination
Federal Communications Commission			
Department of Defense	16020	Consat Rate of Return	1973
Airline Parties	16258	Bell System Rates	July 22, 1968
Airline Parties	18128	TELPAK	3/22, 10/15 1971, Feb. 22, 1972
National Data Corporation	19989	WATS	(none)
Press Wire Services	19919	Private Line Rates	(none)
Aeronautical Radio	20814	Private Line Rates	October 5, 1978
Department of Defense	20690	1,544 Mbps Service	January 30, 1979
State of Hawaii	21263	Interstate Separation	February 7, 1979
International Record Carriers	CC78-97	Telex/TWX Rates	March 6, 1980
ITT World Communications	CC84-633	Rate of Return	(none)
Aeornautical Radio	CC78-72	Access Line Charges	(none)
MCI	CC84-800	Rate of Return	(none)
Ind. Data Com. Mfg. Assn.	CC85-26	AT&T Accounting Plan	(none)
Tymnet, Inc.	ENF84-22	Packet Switching Costs	(none)
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 7/29/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 8/23/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 2/21/95
Nuclear Regulatory Commission			
Fauquier League for Environment Protection	50-328 50-329	Va. Electric Power Co.	1976
Postal Rate Commission			
Association of Third Class Mail Users	R71-1	Rates	1970
Dow Jones & Company	R72-1	Rates	1972
Dow Jones & Company	R74-1	Rates	September 13, 1974
Dow Jones & Company	MC76-2	Rate Structure	January 6, 1979
Dow Jones & Company	MC79-3	Rate Structure	September 12, 1979
Dow Jones & Company	R80-1	Rates	November 25, 1980
Warshawsky & Company	C82-1	Rate Structure	(none)
Dow Jones & Company	R84-1	Postal Costs	June 14, 1984
Dow Jones & Company	R87-1	Rate Structure Costs	November 2, 1987
Dow Jones & Company	R90-1	Rate Structure Costs	Sept 12, Oct 10, 1990
Dow Jones & Company	MC91-1	Pre-barcoding Discounts	November 19, 1991
Dow Jones & Company	MC91-3	Palletization Discounts	March 2, 1992

CHARLES W. KING
Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date of Cross-Examination
U.S. Congress			
National Retail Merchants Association	House/Senate Hearings	Electric Rate Reform Legislation	1976, 1977 & 1979
National Wireless Resellers Association	House Commerce Committee	Interconnection & Resale of Wireless Services	October 12, 1995
Federal Maritime Commission			
State of Hawaii	71-18	Ocean Shipping Rates	October-71
Foss Alaska Line	79-54	Barge Rate Increase	July 1979
Palmetto Shipping and Stevadoring	85-20	Vessel Charge Liability	October 27, 1986
Interstate Commerce Commission			
Western Coal Traffic League	Ex Parte 349	R.R. Rate Increase	May-76
Western Coal Traffic League	Ex Parte 357	R.R. Rate Increase	Oct-78
Western Coal Traffic League	Ex Parte 375 (Sub1)	R.R. Rate Increase	June 1, 1980
Arkansas Power & Light Co.	37276	Cost of Capital	(none)
Central Illinois Light Co.	37450	Cost of Capital	March 10, 1981
Western Coal Traffic League	Ex Parte 347	Costing Methods	(none)
Civil Aeronautics Board			
Thomas Cook, Inc.	36595	Air Fare Deregulation	(none)
Copyright Royalty Tribunal			
Public Broadcasting Service	88-2-86CD	Television Valuation	(none)
Federal Energy Regulatory Commission			
Exxon USA	OR89-2-000	Pipeline Quality Bank	October 18, 1990
Canadian Transport Commission			
Rail Costing Inquiry, 1967-1969 Telecommunications Costing Inquiry, 1972-1975			
Surface Transportation Board			
Williams Energy Services, Inc	Ex Parte 582, Sub 1	Rail Merger Guidelines	April 5, 2001

Montana-Dakota Utilities Company
Gas Division
Snavely King Majoros O'Connor & Lee,Inc.

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	Distribution Plant						
374.20	Rights of Way	89,641	2.58%	2,313	0.75%	672	-1,640
375.00	Distr. Meas & Reg Station Structures	521,210	2.40%	12,509	2.07%	10,789	-1,720
376.00	Mains	78,334,154	4.05%	3,172,533	1.90%	1,485,648	-1,686,885
378.00	Meas & Reg Station Equip-General	1,367,334	2.30%	31,449	1.54%	21,057	-10,392
379.00	Meas & Reg Station Equip-City Gate	1,009,137	2.74%	27,650	2.41%	24,320	-3,330
380.00	Services	32,476,717	7.60%	2,468,231	2.49%	808,966	-1,659,265
381.00	Meters	30,462,008	2.58%	785,920	3.19%	971,738	185,818
383.00	Service Regulators	4,296,862	2.37%	101,836	1.71%	73,476	-28,359
385.00	Industrial Meas. & Reg. Station Equipment	578,200	1.91%	11,044	2.23%	12,894	1,850
	MISCELLANEOUS EQUIPMENT						
386.10	Miscellaneous Property on Customers Premise	1,680	9.35%	157	4.07%	68	-89
386.20	CNG Refueling station	432,811	9.35%	40,468	2.20%	9,522	-30,946
	TOTAL Account 386	434,491	9.35%	40,625	2.21%	9,590	-31,035
	OTHER EQUIPMENT						
387.10	Cathodic Protection Equipment	1,450,657	5.21%	75,579	7.02%	101,836	26,257
387.20	Other Distribution Equipment	557,184	5.21%	29,029	2.56%	14,264	-14,765
	TOTAL Account 387	2,007,841	5.21%	104,609	5.78%	116,100	11,492
	TOTAL Distribution Plant	151,577,594	4.46%	6,758,717	2.33%	3,535,250	-3,223,467
	General Plant						
390.00	General Structures	1,922,983	2.34%	44,998	4.98%	95,765	50,767
	OFFICE FURNITURE & EQUIPMENT						
391.10	Office Furniture & Equipment	544,275	4.05%	22,043	5.60%	30,479	8,436
391.30	Computer Equipment - PC	780,995	12.50%	97,624	5.88%	45,922	-51,702
	TOTAL Account 391	1,325,269	9.03%	119,667	5.77%	76,402	-43,266
	TRANSPORTATION EQUIPMENT						
392.10	Transportation Equipment (Trailers)	147,187	5.74%	8,449	4.30%	6,329	-2,119
392.20	Transportation Equipment (Cars & Trucks)	6,080,561	5.74%	349,024	9.05%	550,291	201,267
	TOTAL Account 392	6,227,748	5.74%	357,473	8.94%	556,620	199,147
393.00	Stores Equipment	186,729	0.90%	1,681	2.56%	4,780	3,100
	TOOLS, SHOP & GARAGE EQ.						
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,422	3.57%	89,087	4.55%	113,542	24,455
394.20	Tools, Shop & Garage Equip. (Unitized)	299,810	4.83%	14,481	4.55%	13,641	-839
394.30	Vehicle Maintenance Equipment	31,177	4.21%	1,313	4.00%	1,247	-65
394.40	Vehicle Refueling Equipment	361,344	9.35%	33,786	5.56%	20,091	-13,695
	TOTAL Account 394	3,187,752	4.35%	138,666	4.65%	148,521	9,855
395.00	Laboratory Equipment	271,033	2.32%	6,288	2.86%	7,752	1,464
	POWER OPERATED EQUIPMENT						
396.10	Work Equipment (Trailers)	293,543	4.83%	14,178	7.45%	21,869	7,691
396.20	Power Operated Equipment	4,081,768	4.83%	197,149	0.00%	0	-197,149
	TOTAL Account 396	4,375,312	4.83%	211,328	0.50%	21,869	-189,459
	COMMUNICATION EQUIPMENT						
397.10	Radio Communication Equip. (Fixed)	481,655	3.67%	17,677	6.67%	32,126	14,450
397.20	Radio Communication Equip. (Mobile)	401,528	3.67%	14,736	6.67%	26,782	12,046
397.30	General Telephone Communication Equip.	90,518	6.56%	5,938	6.67%	6,038	100
397.50	Supervisory & Telemetering Equip.	124,167	6.67%	8,282	8.33%	10,343	2,061
397.60	SCADA System	30,894	15.07%	4,656	0.00%	0	-4,656
397.80	Network Equipment	30,338	12.50%	3,792	6.67%	2,024	-1,769
	TOTAL Account 397	1,159,100	4.75%	55,081	6.67%	77,313	22,232
398.00	Miscellaneous Equipment	145,270	0.59%	857	1.27%	1,851	994
	TOTAL General Plant	18,801,196	4.98%	936,037	5.27%	990,871	54,834
	TOTAL Depreciable Plant	170,378,791	4.52%	7,694,754	2.66%	4,526,122	-3,168,633
	NON-DEPRECIABLE PLANT						
374.10	Land (Distribution)	108,920					
389.00	Land & Land Rights (General)	301,149					
	Total Land	410,069					
	INTANGIBLE PLANT						
303.00	Miscellaneous Intangible Plant	477,530					
	Total Intangible Plant	477,530					
	TOTAL Non-Depreciable Plant	887,598					
	TOTAL Plant in Service	171,266,389					

Montana-Dakota Utilities - Gas Division
Snavely King Majoros O'Connor & Lee , Inc.
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of
Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)		A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT											
	General Plant											
390.00	General Structures	1,922,983	0%	-	1,922,983	1,113,319	809,664		30-R5	8.46	95,705	4.98%
	OFFICE FURNITURE & EQUIPMENT											
391.10	Office Furniture & Equipment	544,275	5%	27,214	517,061	308,169	208,892	(1)	17	Amort.	30,492	5.60%
391.30	Computer Equipment - PC	780,995	0%	-	780,995	293,351	487,644	(1)	17	Amort.	45,941	5.88%
	TOTAL Account 391	1,325,269		27,214	1,298,055	601,519	696,536				76,432	5.77%
	TRANSPORTATION EQUIPMENT											
392.10	Transportation Equipment (Trailers)	147,187	15%	22,078	125,109	91,106	34,003		8-L3	5.37	6,332	4.30%
392.20	Transportation Equipment (Cars & Trucks)	6,080,561	15%	912,084	5,168,477	2,213,865	2,954,612		8-L3	5 37	550,207	9 05%
	TOTAL Account 392	6,227,748		934,162	5,293,586	2,304,970	2,988,615				556,539	8.94%
393.00	Stores Equipment	186,729	0%	-	186,729	126,412	60,317	(1)	39	Amort.	4,788	2.56%
	TOOLS, SHOP & GARAGE EQ.										0	
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,422	10%	249,542	2,245,880	1,213,027	1,032,853	(1)	20	Amort	113,428	4.55%
394.20	Tools, Shop & Garage Equip. (Unitized)	299,810	10%	29,981	269,829	302,930	-33,101	(1)	20	Amort	13,628	4.55%
394.30	Vehicle Maintenance Equipment	31,177	0%	-	31,177	11,256	19,921	(1)	25	Amort.	1,247	4.00%
394.40	Vehicle Refueling Equipment	361,344	20%	0	361,344	234,337	127,007	(1)	15	Amort.	20,075	5.56%
	TOTAL Account 394	3,187,752		279,523	2,908,229	1,761,549	1,146,680				148,378	4.65%
395.00	Laboratory Equipment	271,033	0%	-	271,033	57,665	213,368	(1)	35	Amort.	7,744	2.86%
	POWER OPERATED EQUIPMENT											
396.10	Work Equipment (Trailers)	293,543	25%	73,386	220,158	91,089	129,069		10-R2	5.90	21,876	7 45%
396.20	Power Operated Equipment	4,081,768	60%	2,449,061	1,632,707	2,254,640	-621,933		7-R2	3 20	0	0 00% (2)
	TOTAL Account 396	4,375,312		2,522,447	1,852,865	2,345,729	-492,864				21,876	0.50%
	COMMUNICATION EQUIPMENT											
397.10	Radio Communication Equip. (Fixed)	481,655	0%	-	481,655	255,394	226,261	(1)	15	Amort.	32,110	6.67%
397 20	Radio Communication Equip. (Mobile)	401,528	0%	-	401,528	170,152	231,376	(1)	15	Amort.	26,769	6.67%
397.30	General Telephone Communication Equip.	90,518	0%	-	90,518	34,571	55,947	(1)	15	Amort.	6,035	6 67%
397.50	Supervisory & Telemetering Equip.	124,167	0%	-	124,167	123,661	506	(1)	12	Amort.	10,347	8.33%
397.60	SCADA System	30,894	0%	-	30,894	30,894	0	(1)		Amort.	0	0.00%
397.80	.Network Equipment	30,338	0%	-	30,338	11,890	18,448	(1)	15	Amort.	2,023	6.67%
	TOTAL Account 397	1,159,100		-	1,159,100	626,563	532,537				77,283	6 67%
398.00	Miscellaneous Equipment	145,270	0%	-	145,270	70,042	75,227	(1)	20-R2	N/A	1,851	1.27%
	TOTAL General Plant	18,801,196		3,763,346	15,037,850	9,007,770	6,030,081				990,596	5 27%
	TOTAL Depreciable Plant	170,378,791		(15,553,665)	185,932,456	107,774,218	78,158,237				3,331,338	1.96%

(CWK-1)
Schedule 2

Montana-Dakota Utilities - Gas Division
Snavely King Majoros O'Connor & Lee , Inc
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of
Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No (a)	Description (b)	Orginal Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A S L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	Distribution Plant										
374.20	Rights of Way	89,641	0%	-	89,641	56,340	33,301	65-R2.5	49 30	675	0.75%
375.00	Distr. Meas & Reg Station Structures	521,210	-19%	(99,030)	620,240	277,079	343,161	55-S1 5	31.86	10,771	2.07%
376.00	Mains	78,334,154	-10%	(7,833,415)	86,167,569	54,180,032	31,987,537	58	43 27	739,254	1.90% WL
378.00	Meas & Reg Station Equip-General	1,367,334	-12%	(164,080)	1,531,414	724,344	807,070	50-SC	38 22	21,116	1 54%
379.00	Meas & Reg Station Equip-City Gate	1,009,137	15%	151,371	857,766	334,885	522,881	40-S1	21.51	24,309	2 41%
380.00	Services	32,476,717	-37%	(12,016,385)	44,493,102	28,893,790	15,599,313	55	43.32	360,095	2.49% WL
381.00	Meters	30,462,008	0%	-	30,462,008	11,110,551	19,351,457	35-R2 5	19 90	972,435	3.19%
383.00	Service Regulators	4,296,862	15%	644,529	3,652,332	1,645,381	2,006,951	40-R1	27 27	73,596	1.71%
385.00	Industrial Meas. & Reg Station Equipment	578,200	0%	-	578,200	215,549	362,651	40-R1	28.16	12,878	2 23%
	Sub	149,135,262		(19,317,011)	168,452,273	97,437,949	71,014,324			2,215,130	
	MISCELLANEOUS EQUIPMENT										
386.10	Miscellaneous Property on Customers Premise	1,680	0%	-	1,680	748	932	20-R2	13 63	68	4 07%
386.20	CNG Refueling station	432,811	0%	-	432,811	303,145	129,666	20-R2	13.63	9,513	2.20%
	TOTAL Account 386	434,491		-	434,491	303,893	130,599			9,582	2 21%
	OTHER EQUIPMENT										
387.10	Cathodic Protection Equipment	1,450,657	0%	-	1,450,657	607,867	842,790	20-L4	8.28	101,786	7.02%
387.20	Other Distribution Equipment	557,184	0%	-	557,184	416,740	140,444	20-L4	9 86	14,244	2.56%
	TOTAL Account 387	2,007,841		-	2,007,841	1,024,607	983,234			116,030	5 78%
	TOTAL Distribution Plant	151,577,595		(19,317,011)	170,894,605	98,766,449	72,128,157			2,340,742	1 54%

WL = Whole Life Rate

Montana-Dakota Utilities - Gas Division
Snavely King Majoros O'Connor & Lee , Inc.
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of
Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A S.L / Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Depreciation Rate (l)
	DEPRECIABLE PLANT										
	NON-DEPRECIABLE PLANT										
374.10	Land (Distribution)	108,920									
389.00	Land & Land Rights (General)	301,149									
						0 00					
	Total Land	410,069									
	INTANGIBLE PLANT										
303 00	Miscellaneous Intangible Plant	477,530				437,461 01					
	Total Intangible Plant	477,530				437,461.01					
	TOTAL Non-Depreciable Plant	887,598				437,461.01					
	TOTAL Plant in Service	171,266,389				108,211,679.43					

(1) Implicit Depreciation Rates and Annual Accrual Based Upon General Plant Amortization Calculation
(2) Account Fully Depreciated. See Narrative In Section 4.

Montana-Dakota Utilities Company
Common Plant
Snavely King Majoros O'Connor & Lee, inc.
Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	General Plant						
390.0	General Structures	18,048,459	3.76%	678,622	3.57%	644,330	-34,292
	OFFICE FURNITURE & EQUIPMENT						
391.1	Office Furniture & Equipment	3,716,417	1.48%	55,003	7.92%	294,340	239,337
391.2	Computer Equipment - Honeywell	93,392	14.17%	13,234	1.52%	1,420	-11,814
391.3	Computer Equipment - PC	4,212,743	12.50%	526,593	6.67%	280,990	-245,603
391.5	Computer Equipment - Other	820,400	26.51%	217,488	0.46%	3,774	-213,714
	TOTAL Account 391	8,842,952	9.19%	812,317	6.56%	580,524	-231,794
	TRANSPORTATION EQUIPMENT						
392.1	Transportation Equipment (Trailers)	251,166	5.74%	14,417	0.00%	0	-14,417
392.2	Transportation Equipment (Cars & Trucks)	4,429,702	5.74%	254,265	8.80%	389,814	135,549
	TOTAL Account 392	4,680,867	5.74%	268,682	8.33%	389,814	121,132
393.0	Stores Equipment	47,386	3.36%	1,592	2.56%	1,213	-379
	TOOLS, SHOP & GARAGE EQ.						
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026	3.44%	8,085	5.00%	11,751	3,666
394.3	Vehicle Maintenance Equipment	102,746	4.46%	4,582	4.00%	4,110	-473
394.4	Vehicle Refueling Equipment	838,831	8.42%	70,630	6.67%	55,950	-14,680
	TOTAL Account 394	1,176,603	7.08%	83,297	6.10%	71,811	-11,486
396.2	Power Operated Equipment	157,573	4.83%	7,611	2.10%	3,309	-4,302
	COMMUNICATION EQUIPMENT						
397.1	Radio Communication Equip. (Fixed)	646,187	4.33%	27,980	6.67%	43,101	15,121
397.2	Radio Communication Equip. (Mobile)	1,285,023	6.68%	85,840	6.67%	85,711	-129
397.3	General Telephone Communication Equip.	779,821	10.62%	82,817	6.33%	49,363	-33,454
397.5	Supervisory & Telemetering Equip.	48,296	0.59%	285	6.67%	3,221	2,936
397.8	Network Equipment	824,948	12.50%	103,119	6.67%	55,024	-48,094
	TOTAL Account 397	3,584,275	8.37%	300,040	6.60%	236,420	-63,620
398.0	Miscellaneous Equipment	592,895	2.51%	14,882	4.75%	28,163	13,281
	TOTAL General Plant	37,131,010	5.84%	2,167,043	5.27%	1,955,583	-211,460
	TOTAL Depreciable Plant	37,131,010	5.84%	2,167,043	5.27%	1,955,583	-211,460
	Amortizable Plant						
392.3	Aircraft Equipment	1,024,350					
	TOTAL Amortizable Plant	1,024,350					
	NON-DEPRECIABLE PLANT						
389.0	Land & Land Rights (General)	1,547,409					
	Total Land	1,547,409					
	INTANGIBLE PLANT						
303.0	Miscellaneous Intangible Plant	13,553,859					
	Total Intangible Plant	13,553,859					
	TOTAL Non-Depreciable Plant	15,101,268					
	TOTAL Plant in Service	53,256,628					

Montana-Dakota Utilities Company
Common Plant
Snavely King Majoros O'Connor & Lee, Inc.
Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of
Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)		A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT											
	General Plant											
390.0	General Structures	18,048,459	0%	0	18,048,459	8,706,838	9,341,621		30-R5	14.5	645,140	3.57%
	OFFICE FURNITURE & EQUIPMENT											
391.1	Office Furniture & Equipment	3,716,417	5%	185,821	3,530,596	1,911,562	1,619,034	(1)	12	Amort.	294,216	7.92%
391.2	Computer Equipment - Honeywell	93,392	0%	0	93,392	99,579	-6,187	(1)	7-R1	N/A	1,417	1.52%
391.3	Computer Equipment - PC	4,212,743	0%	0	4,212,743	1,759,816	2,452,927	(1)	15	Amort.	280,850	6 67%
391.5	Computer Equipment - Other	820,400	0%	0	820,400	821,581	-1,181	(1)	11-R3	N/A	3,798	0.46%
	TOTAL Account 391	8,842,952		185,821	8,657,131	4,592,538	4,064,593				580,280	6.56%
	TRANSPORTATION EQUIPMENT											
392.1	Transportation Equipment (Trailers)	251,166	15%	37,675	213,491	251,166	-37,675		20-L2	10.8	-	0.00% (2)
392.2	Transportation Equipment (Cars & Trucks)	4,429,702	20%	885,940	3,543,761	1,477,128	2,066,633		13-L1	5.3	389,931	8.80%
	TOTAL Account 392	4,680,867		923,615	3,757,252	1,728,294	2,028,958				389,931	8.33%
393.0	Stores Equipment	47,386	0%	0	47,386	14,487	32,898	(1)	39	Amort.	1,215	2.56%
	TOOLS, SHOP & GARAGE EQ.											
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026	0%	0	235,026	36,458	198,568	(1)	20	Amort.	11,751	5 00%
394.3	Vehicle Maintenance Equipment	102,746	0%	0	102,746	39,144	63,602	(1)	25	Amort.	4,110	4.00%
394.4	Vehicle Refueling Equipment	838,831	0%	0	838,831	561,055	277,776	(1)	15	Amort.	55,922	6.67%
	TOTAL Account 394	1,176,603		0	1,176,603	636,657	539,946				71,783	6.10%
396.2	Power Operated Equipment	157,573	45%	70,908	86,665	58,932	27,733		10	8.4	3,302	2.10%
	COMMUNICATION EQUIPMENT											
397.1	Radio Communication Equip. (Fixed)	646,187	0%	0	646,187	409,278	236,909	(1)	15	Amort.	43,079	6.67%
397.2	Radio Communication Equip. (Mobile)	1,285,023	0%	0	1,285,023	1,034,022	251,001	(1)	15	Amort.	85,668	6.67%
397.3	General Telephone Communication Equip.	779,821	5%	38,991	740,830	419,620	321,210	(1)	15	Amort.	49,389	6.33%
397.5	Supervisory & Telemetering Equip.	48,296	0%	0	48,296	46,185	2,111	(1)	15	Amort.	3,220	6.67%
397.8	Network Equipment	824,948	0%	0	824,948	330,669	494,280	(1)	15	Amort.	54,997	6.67%
	TOTAL Account 397	3,584,275		38,991	3,545,284	2,239,773	1,305,511				236,352	6.59%
398.0	Miscellaneous Equipment	592,895	5%	29,645	563,250	372,787	190,463	(1)	20	Amort.	28,163	4.75%
	TOTAL General Plant	37,131,010		1,248,980	35,882,031	18,350,306	17,531,724				1,956,165	5.27%
	TOTAL Depreciable Plant	37,131,010		1,248,980	35,882,031	18,350,306	17,531,724				1,956,165	5.27%

(CWK-1)
Schedule 4

Montana-Dakota Utilities Company
Common Plant
Snavely King Majoros O'Connor & Lee, Inc.
Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of
Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	Amortizable Plant										
392.3	Aircraft Equipment	1,024,350				282,080					
	TOTAL Amortizable Plant	1,024,350				282,080					
	NON-DEPRECIABLE PLANT										
389.0	Land & Land Rights (General)	1,547,409				0					
	Total Land	1,547,409				0					
	INTANGIBLE PLANT										
303.0	Miscellaneous Intangible Plant	13,553,859				5,006,700					
	Total Intangible Plant	13,553,859				5,006,700					
	TOTAL Non-Depreciable Plant	15,101,268				5,006,700					
	TOTAL Plant in Service	53,256,628				23,639,086					

(1) Implicit Depreciation Rates and Annual Accrual Based Upon General Plant Amortization Calculation
(2) Account Fully Depreciated. See Narrative In Section 4.

(CWK-1)
chedule 4

Montana-Dakota Utilities Company
Common Plant
Snavely King Majoros O'Connor & Lee, Inc.
Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of
Book Deprecation Reserve and Average Remaining Lives as of December 31, 2001

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Orginal Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	Amortizable Plant										
392.3	Aircraft Equipment	1,024,350				282,080					
	TOTAL Amortizable Plant	1,024,350				282,080					
	NON-DEPRECIABLE PLANT										
389.0	Land & Land Rights (General)	1,547,409				0					
	Total Land	1,547,409				0					
	INTANGIBLE PLANT										
303.0	Miscellaneous Intangible Plant	13,553,859				5,006,700					
	Total Intangible Plant	13,553,859				5,006,700					
	TOTAL Non-Depreciable Plant	15,101,268				5,006,700					
	TOTAL Plant in Service	53,256,628				23,639,086					

(1) Implicit Depreciation Rates and Annual Accrual Based Upon General Plant Amortization Calculation
(2) Account Fully Depreciated. See Narrative In Section 4.

IMULATED PLANT-RECORD SURVIVOR ANALYSIS SUMMARY

Gas Division

- MDU GAS 374 RIGHTS OF WAY
- MDU GAS 375 STRUCTURES AND IMPROVEMENT
- MDU GAS 376 DISTRIBUTION MAINS
- MDU GAS 378 MEAS AND REG STATION EQUIP - GENERAL
- MDU GAS 379 MEAS AND REG STATION EQUIP - CITY GATE
- MDU GAS 380 SERVICES
- MDU GAS 381 METERS
- MDU GAS 383 HOUSE REGULATORS
- MDU GAS 385 INDUSTRIAL MEAS. AND REG STATION EQUIOPMENT
- MDU GAS 387 CATHODIC PROTECTION AND OTHER DISTRIBUTION
- MDU GAS 391 OFFICE FURNITURE, EQUIPMENT AND COMPUTER
- MDU GAS 393 STORES EQUIPMENT
- MDU GAS 394 TOOLS, SHOP AND GARAGE EQUIP.
- MDU GAS 396 POWER OPERATED EQUIPMENT
- MDU GAS 397 COMMUNICATIONS EQUIPMENT

Common Division

- MDU COMMON 389 LAND AND LAND RIGHTS
- MDU COMMON 390 STRUCTURES AND IMPROVEMENTS
- MDU COMMON 391 OFFICE FURNITURE, COMPUTER EQUIPMENT
- MDU COMMON 397 COMMUNICATIONS EQUIPMENT

MDU GAS 374 RIGHTS OF WAY
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 374 - RIGHTS OF WAY
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 74 INTERVAL: 0 OBSERVATION BAND: 1928 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	139.9	.6606E+09	36	48.71
O3	104.6	.6826E+09	36	50.52
SC	66.0	.7356E+09	38	55.70
O2	74.0	.7359E+09	38	55.63
R0.5	58.1	.8930E+09	42	65.36
S-.5	57.9	.1033E+10	45	65.96
L0	65.0	.1065E+10	46	62.09
R1	52.5	.1213E+10	49	77.62
L0.5	59.4	.1358E+10	52	68.22
S0	52.8	.1569E+10	55	76.16
R1.5	49.4	.1662E+10	57	87.83
L1	54.7	.1800E+10	59	74.64
S0.5	49.7	.2010E+10	63	84.60
L1.5	51.5	.2267E+10	67	80.93
R2	46.5	.2291E+10	67	96.28
S1	47.5	.2601E+10	72	91.36
R2.5	44.8	.2882E+10	75	98.98
L2	48.7	.2917E+10	76	86.53
S1.5	45.8	.3100E+10	78	95.79
R3	43.7	.3592E+10	84	90.89
S2	44.7	.3702E+10	85	98.58
L3	45.3	.4038E+10	89	94.69
S3	43.1	.4618E+10	96	99.94
R4	42.6	.4624E+10	96	100.00
L4	43.0	.5056E+10	100	99.63
S4	42.5	.5434E+10	104	100.00
L5	42.0	.5909E+10	108	100.00
R5	42.4	.5994E+10	109	100.00
S5	41.4	.6303E+10	112	100.00
S6	43.3	.7665E+10	123	100.00
SQ	47.2	.1300E+11	161	100.00

MDU GAS 375 STRUCTURES AND IMPROVEMENT
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 375 - STRUCTURES AND IMPROVEMENTS
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 84 INTERVAL: 0 OBSERVATION BAND: 1918 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
S1.5	54.1	.6084E+11	94	92.81
S2	52.8	.6296E+11	95	96.74
S1	55.5	.6638E+11	98	88.14
S3	51.0	.7342E+11	103	99.68
S0.5	57.5	.7750E+11	106	81.93
S4	49.2	.8490E+11	111	100.00
L0	88.8	.8606E+11	111	51.19
S5	48.4	.9778E+11	119	100.00
S0	59.6	.9857E+11	119	75.73
L0.5	66.1	.1057E+12	124	68.75
S6	50.2	.1198E+12	132	100.00
L1	71.9	.1208E+12	132	63.70
L1.5	58.3	.1359E+12	140	80.35
S-.5	62.1	.1531E+12	149	69.37
L2	62.8	.1607E+12	153	77.46
L3	51.4	.1829E+12	163	94.25
SQ	41.9	.1878E+12	165	100.00
L4	52.7	.2200E+12	179	98.31
R0.5	75.2	.2277E+12	182	54.67
R1	60.9	.2484E+12	190	74.39
L5	47.2	.2594E+12	194	100.00
SC	64.3	.2649E+12	196	64.14
R1.5	66.3	.2801E+12	202	69.03
R2	53.7	.2975E+12	208	94.42
R2.5	58.5	.3331E+12	220	91.12
R3	48.3	.3643E+12	230	100.00
R4	52.6	.3969E+12	240	100.00
O2	97.0	.4312E+12	250	47.71
R5	45.7	.4428E+12	253	100.00
O3	140.6	.4680E+12	261	43.83
O4	185.3	.5011E+12	270	43.29

MDU GAS 376 MAINS
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 376 - MAINS
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 86 INTERVAL: 0 OBSERVATION BAND: 1916 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	202.2	.4640E+14	36	41.63
O3	149.7	.4691E+14	36	42.88
SC	92.3	.4795E+14	36	46.29
O2	103.8	.4797E+14	36	46.22
R0.5	76.9	.5155E+14	38	55.62
S-.5	74.4	.5700E+14	40	58.92
R1	65.1	.5872E+14	40	71.33
L0	82.1	.6047E+14	41	57.41
L0.5	71.3	.6771E+14	43	66.15
R1.5	57.6	.6805E+14	43	87.56
S0	61.7	.7251E+14	45	75.81
L1	62.6	.7943E+14	47	75.80
R2	52.1	.8034E+14	47	98.05
S0.5	56.3	.8156E+14	47	86.72
L1.5	57.1	.8732E+14	49	83.89
R2.5	48.5	.8815E+14	49	99.90
S1	51.9	.9374E+14	51	95.35
R3	44.7	.9780E+14	52	100.00
L2	52.6	.9962E+14	52	90.50
S1.5	49.1	.1003E+15	53	98.77
R4	43.2	.1087E+15	55	100.00
S2	46.9	.1087E+15	55	99.92
L3	47.1	.1135E+15	56	98.26
S3	44.1	.1150E+15	56	100.00
L4	43.9	.1210E+15	58	99.99
S4	42.2	.1233E+15	58	100.00
L5	42.3	.1275E+15	59	100.00
R5	42.5	.1293E+15	60	100.00
S5	41.5	.1319E+15	60	100.00
SQ	37.7	.1739E+15	70	100.00
S6	44.8	.2063E+15	76	100.00

MDU GAS 378 MEAS AND REG STATION EQUIP
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 378 - MEAS AND REG STATION EQUIP
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 82 INTERVAL: 0 OBSERVATION BAND: 1920 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	99.8	.2161E+11	32	62.54
O3	75.4	.2269E+11	33	66.73
O2	55.8	.2630E+11	35	77.64
SC	49.6	.2680E+11	36	82.20
L0	50.4	.3326E+11	40	82.60
R0.5	45.8	.3388E+11	40	93.12
S-.5	45.7	.3560E+11	41	92.40
L0.5	46.9	.3957E+11	43	88.17
R1	42.6	.4369E+11	46	99.51
L1	44.1	.4793E+11	48	92.90
S0	42.5	.4818E+11	48	99.13
R1.5	40.7	.5167E+11	50	100.00
L1.5	41.7	.5474E+11	51	96.22
S0.5	40.7	.5577E+11	52	56.08
R2	38.5	.5798E+11	53	100.00
R2.5	37.6	.5990E+11	53	100.00
L2	40.3	.6256E+11	55	98.21
S1	39.6	.6399E+11	55	100.00
R3	37.0	.6732E+11	57	100.00
S1.5	38.3	.6810E+11	57	100.00
S2	37.3	.7099E+11	58	100.00
L3	37.9	.7270E+11	59	99.95
S3	36.0	.7354E+11	59	100.00
L4	35.8	.7715E+11	61	100.00
S4	35.5	.8182E+11	63	100.00
L5	35.6	.8206E+11	63	100.00
S5	34.9	.8705E+11	64	100.00
S6	34.8	.9281E+11	67	100.00
R4	37.6	.1010E+12	70	100.00
SQ	35.3	.1055E+12	71	100.00
R5	31.0	.2144E+12	101	100.00

MDU GAS 379 MEAS AND REG STATION EQUIP - CITY GATE
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 379 - MEAS AND REG STATION EQUIP - CITY GATE
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 51 INTERVAL: 0 OBSERVATION BAND: 1951 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
SC	57.3	.1772E+13	201	42.29
S-.5	41.8	.2386E+13	234	59.54
S0	41.4	.3972E+13	302	61.87
S0.5	41.0	.6091E+13	374	64.51
S1	40.6	.8829E+13	450	67.36
S1.5	40.2	.1212E+14	527	70.93
S2	39.8	.1601E+14	606	74.71
S3	39.4	.2070E+14	689	82.17
S4	39.0	.2602E+14	772	91.87
S5	38.6	.3178E+14	854	98.61
S6	38.2	.3798E+14	933	99.99
SQ	37.8	.4489E+14	1015	100.00
L0	37.4	.4883E+14	1058	70.06
L0.5	37.1	.5652E+14	1139	71.76
L1	36.7	.6485E+14	1220	73.56
L1.5	36.3	.7384E+14	1302	76.45
L2	36.0	.8345E+14	1384	79.35
L3	35.6	.9386E+14	1468	85.14
L4	35.2	.1049E+15	1552	92.97
L5	34.9	.1165E+15	1635	98.01
R0.5	34.5	.1261E+15	1701	74.11
R1	34.2	.1384E+15	1782	79.01
R1.5	33.8	.1514E+15	1864	84.31
R2	33.5	.1650E+15	1946	89.58
R2.5	33.2	.1793E+15	2029	93.96
R3	32.8	.1942E+15	2111	97.90
R4	32.5	.2099E+15	2195	100.00
R5	32.2	.2263E+15	2279	100.00
O2	31.9	.2409E+15	2352	79.71
O3	.1	.3965E+15	3017	100.00
O4	.1	.3965E+15	3017	100.00

MDU GAS 380 SERVICES
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 380 - SERVICES
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 82 INTERVAL: 0 OBSERVATION BAND: 1920 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	161.4	.6855E+12	14	47.40
O3	119.5	.7022E+12	14	49.40
SC	74.8	.7388E+12	14	54.48
O2	83.7	.7403E+12	14	54.57
R0.5	63.5	.8809E+12	16	66.52
S-.5	61.4	.1132E+13	18	69.20
R1	54.6	.1194E+13	18	83.91
L0	68.6	.1363E+13	20	64.98
R1.5	48.9	.1590E+13	21	95.98
L0.5	60.2	.1725E+13	22	73.92
S0	52.3	.2060E+13	24	85.70
R2	44.6	.2148E+13	25	99.99
R2.5	42.0	.2410E+13	26	100.00
L1	53.3	.2413E+13	26	83.03
S0.5	48.2	.2534E+13	27	94.35
L1.5	49.1	.2830E+13	28	89.62
R3	39.7	.3069E+13	30	100.00
S1	44.9	.3231E+13	30	99.15
S1.5	42.5	.3476E+13	31	99.95
L2	45.3	.3516E+13	32	94.94
S2	40.6	.3860E+13	33	100.00
R4	37.7	.4058E+13	34	100.00
S3	38.2	.4100E+13	34	100.00
L3	40.5	.4124E+13	34	99.68
L4	37.7	.4249E+13	35	100.00
S4	36.8	.4553E+13	36	100.00
L5	36.4	.4582E+13	36	100.00
R5	36.0	.4706E+13	37	100.00
S5	35.9	.4752E+13	37	100.00
S6	35.4	.4903E+13	37	100.00
SQ	38.1	.1175E+14	58	100.00

MDU GAS 381 - METERS
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 381 - METERS
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 69 INTERVAL: 0 OBSERVATION BAND: 1933 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	116.1	.5757E+13	32	52.51
O3	86.8	.6006E+13	33	54.96
SC	54.5	.6563E+13	34	62.81
O2	61.4	.6565E+13	34	62.20
R0.5	47.5	.8086E+13	38	76.37
S-.5	46.9	.9626E+13	42	76.68
L0	52.1	.1023E+14	43	70.89
R1	42.1	.1078E+14	44	91.58
L0.5	47.1	.1284E+14	48	78.32
R1.5	38.8	.1396E+14	50	98.33
S0	41.5	.1457E+14	52	90.21
L1	43.0	.1674E+14	55	85.48
S0.5	39.1	.1781E+14	57	96.38
R2	35.8	.1795E+14	57	100.00
L1.5	40.0	.1971E+14	60	91.16
R2.5	34.9	.2110E+14	62	100.00
S1	36.7	.2197E+14	63	99.64
L2	37.3	.2382E+14	66	95.69
S1.5	35.5	.2460E+14	67	99.97
R3	33.3	.2603E+14	69	100.00
S2	34.2	.2769E+14	71	100.00
L3	34.3	.2872E+14	73	99.62
S3	32.7	.3095E+14	75	100.00
L4	32.3	.3128E+14	76	100.00
R4	31.8	.3129E+14	76	100.00
L5	30.9	.3280E+14	78	100.00
S5	30.8	.3281E+14	78	100.00
S4	31.3	.3297E+14	78	100.00
R5	30.4	.3306E+14	78	100.00
S6	32.5	.4472E+14	91	100.00
SQ	26.6	.6029E+14	105	100.00

MDU GAS 383 HOUSE REGULATORS
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 383 - HOUSE REGULATORS
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 56 INTERVAL: 0 OBSERVATION BAND: 1946 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O3	76.8	.7918E+11	22	51.59
SC	48.8	.7921E+11	22	56.82
O2	54.3	.7922E+11	22	57.18
O4	102.7	.8021E+11	22	49.63
L0	47.9	.8204E+11	22	63.49
R0.5	42.9	.8463E+11	23	67.32
S-.5	42.8	.8620E+11	23	67.44
L0.5	43.3	.1004E+12	25	70.40
R1	38.7	.1098E+12	26	80.02
S0	38.7	.1244E+12	28	78.71
L1	39.9	.1362E+12	29	76.93
R1.5	36.4	.1584E+12	31	89.90
S0.5	36.6	.1701E+12	32	86.57
L1.5	37.5	.1771E+12	33	83.09
L2	35.9	.2330E+12	38	87.91
R2	34.8	.2341E+12	38	96.71
S1	35.0	.2345E+12	38	93.03
S1.5	34.1	.2920E+12	43	96.44
R2.5	33.6	.3094E+12	44	99.14
L3	33.4	.3290E+12	45	95.64
S2	32.9	.3564E+12	47	99.13
R3	32.4	.3918E+12	50	100.00
L4	31.7	.4248E+12	52	99.78
S3	31.8	.4376E+12	52	99.98
R4	31.9	.4563E+12	53	100.00
S6	30.1	.4592E+12	54	100.00
S5	30.8	.4620E+12	54	100.00
L5	30.6	.4678E+12	54	100.00
S4	31.6	.4848E+12	55	100.00
R5	31.1	.5017E+12	56	100.00
SQ	30.8	.5818E+12	60	100.00

MDU GAS 385 IND MEAS AND REG STATION EQUIOPMENT
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 385 - IND MEAS AND REG STATION EQUIPMENT
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 51 INTERVAL: 0 OBSERVATION BAND: 1951 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	94.0	.7556E+09	20	49.43
O3	70.3	.7600E+09	20	51.35
O2	50.2	.7907E+09	21	56.28
SC	44.6	.7929E+09	21	56.59
R0.5	39.6	.9442E+09	23	65.99
L0	44.0	.1017E+10	23	62.96
S-.5	39.1	.1025E+10	23	67.14
L0.5	39.8	.1273E+10	26	69.82
R1	35.8	.1372E+10	27	78.40
S0	35.4	.1618E+10	30	78.37
L1	36.7	.1726E+10	31	76.32
R1.5	33.7	.2125E+10	34	88.52
S0.5	33.8	.2234E+10	35	85.42
L1.5	34.7	.2378E+10	36	82.14
S1	32.3	.3118E+10	41	92.07
L2	33.1	.3287E+10	42	87.05
R2	32.2	.3308E+10	43	95.80
S1.5	31.5	.4108E+10	48	95.78
R2.5	31.1	.4772E+10	51	98.79
S2	30.7	.5335E+10	54	98.58
L3	31.2	.5785E+10	56	94.65
R3	30.3	.6610E+10	60	100.00
S3	29.9	.8102E+10	67	99.91
L4	30.1	.9472E+10	72	99.47
R4	29.8	.1016E+11	75	100.00
S4	29.5	.1218E+11	82	100.00
L5	29.6	.1332E+11	86	99.99
R5	29.7	.1384E+11	88	100.00
S5	29.3	.1585E+11	94	100.00
S6	30.1	.1824E+11	101	100.00
SQ	30.8	.2308E+11	113	100.00

MDU GAS 387 CATHODIC PROTECTION AND OTHER DISTRIBUTION
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 387 - CATHODIC PROTECTION AND OTHER DISTRIBUTION EQUIPMENT
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 54 INTERVAL: 0 OBSERVATION BAND: 1948 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	48.4	.4622E+11	50	70.57
O3	37.3	.4872E+11	51	76.13
L4	20.0	.5513E+11	54	100.00
O2	28.4	.5617E+11	55	88.09
SC	25.7	.6038E+11	57	100.00
R2	21.3	.6139E+11	57	100.00
S3	19.7	.6210E+11	58	100.00
L0	26.0	.6368E+11	59	93.27
R2.5	20.7	.6563E+11	59	100.00
L0.5	24.7	.6819E+11	61	96.38
R1.5	22.0	.6944E+11	61	100.00
S-.5	23.7	.6950E+11	61	100.00
R0.5	25.0	.6976E+11	61	100.00
L3	20.7	.7017E+11	61	100.00
S2	20.5	.7023E+11	61	100.00
R1	23.1	.7050E+11	62	100.00
S1.5	21.0	.7285E+11	63	100.00
S1	21.3	.7297E+11	63	100.00
L1	23.5	.7348E+11	63	98.74
L1.5	22.4	.7390E+11	63	99.58
L2	21.6	.7508E+11	64	99.95
S0	22.9	.7624E+11	64	100.00
S0.5	22.1	.7642E+11	64	100.00
S4	20.5	.8037E+11	66	100.00
R3	21.3	.8284E+11	67	100.00
R4	18.1	.9348E+11	71	100.00
R5	21.0	.1234E+12	82	100.00
L5	21.5	.1537E+12	91	100.00
S5	16.6	.2021E+12	105	100.00
S6	21.8	.2096E+12	107	100.00
SQ	15.9	.3468E+12	137	100.00

MDU GAS 391 OFFICE FURNITURE, EQUIPMENT AND COMPUTER
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 391 - OFFICE FURNITURE, EQUIPMENT AND COMPUTER EQUIPMENT
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 70 INTERVAL: 0 OBSERVATION BAND: 1932 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
S1	29.8	.1033E+12	59	100.00
L1	32.7	.1062E+12	60	97.46
L0.5	34.7	.1081E+12	61	94.05
L1.5	31.5	.1081E+12	61	98.80
S-.5	33.8	.1096E+12	61	100.00
L0	36.9	.1103E+12	61	89.84
R0.5	34.3	.1106E+12	61	100.00
L2	30.1	.1106E+12	61	99.73
R2	29.9	.1107E+12	61	100.00
SC	36.7	.1121E+12	62	94.70
R1.5	31.3	.1126E+12	62	100.00
S1.5	30.0	.1136E+12	62	100.00
S0	33.0	.1144E+12	63	100.00
O2	40.7	.1149E+12	63	84.66
R2.5	29.1	.1157E+12	63	100.00
S2	29.5	.1191E+12	64	100.00
O3	53.9	.1196E+12	64	72.75
O4	70.7	.1218E+12	65	67.63
R4	27.8	.1278E+12	66	100.00
L4	27.3	.1287E+12	66	100.00
L3	30.0	.1393E+12	69	100.00
R5	27.7	.1433E+12	70	100.00
L5	27.2	.1442E+12	70	100.00
S0.5	28.6	.1489E+12	71	100.00
S4	28.3	.1499E+12	72	100.00
R1	29.5	.1610E+12	74	100.00
R3	30.8	.1817E+12	79	100.00
S5	29.0	.1862E+12	80	100.00
SQ	29.3	.2055E+12	84	100.00
S6	24.7	.2314E+12	89	100.00
S3	24.6	.2664E+12	96	100.00

MDU GAS 393 STORES EQUIPMENT
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 393 - STORES EQUIPMENT
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 82 INTERVAL: 0 OBSERVATION BAND: 1920 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	667.1	.1879E+09	20	13.53
O3	488.8	.1883E+09	20	13.57
SC	300.2	.1892E+09	20	13.58
O2	335.6	.1892E+09	20	13.62
R0.5	235.1	.1940E+09	20	14.19
R1	179.1	.2061E+09	21	15.39
S-.5	205.8	.2141E+09	21	15.88
R1.5	141.4	.2251E+09	21	17.56
L0	215.9	.2439E+09	22	17.67
L0.5	172.1	.2631E+09	23	20.02
R2	111.6	.2747E+09	24	22.96
S0	143.3	.2887E+09	24	21.43
L1	137.2	.3192E+09	26	25.14
S0.5	120.1	.3240E+09	26	25.43
R2.5	95.9	.3302E+09	26	29.27
L1.5	116.8	.3599E+09	27	29.54
S1	102.2	.3981E+09	29	32.04
R3	84.2	.4389E+09	30	40.84
S1.5	93.3	.4432E+09	30	36.92
L2	100.5	.4498E+09	31	37.73
S2	85.2	.5251E+09	33	44.88
L3	84.2	.5903E+09	35	52.20
R4	74.6	.6435E+09	37	64.58
S3	76.2	.6599E+09	37	60.73
L4	75.3	.7389E+09	39	68.23
S4	71.7	.8416E+09	42	78.02
L5	71.3	.9176E+09	44	83.23
R5	70.5	.9208E+09	44	88.90
S5	69.9	.1020E+10	46	91.93
S6	69.5	.1164E+10	49	98.93
SQ	68.5	.1300E+10	52	100.00

MDU GAS 394 TOOLS, SHOP, AND GARAGE EQUIP.
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 394 - TOOLS, SHOP & GARAGE EQ.
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 56 INTERVAL: 0 OBSERVATION BAND: 1946 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O3	108.4	.4943E+10	5	39.09
O4	146.4	.4970E+10	5	38.19
SC	67.3	.4989E+10	5	41.22
O2	75.9	.5064E+10	5	41.03
R0.5	57.2	.6218E+10	6	46.69
S-.5	55.3	.8654E+10	7	50.21
L0	61.5	.1029E+11	7	49.71
R1	48.7	.1204E+11	8	57.74
L0.5	53.9	.1708E+11	10	56.53
S0	47.1	.2416E+11	12	62.34
R1.5	44.0	.2590E+11	12	70.52
L1	48.2	.2906E+11	13	63.92
S0.5	43.8	.3862E+11	15	70.66
L1.5	44.5	.4384E+11	16	71.66
R2	40.6	.5204E+11	17	83.69
S1	40.8	.6002E+11	19	80.18
L2	41.4	.6354E+11	19	78.89
S1.5	39.0	.7894E+11	22	87.59
R2.5	38.8	.8183E+11	22	92.35
S2	37.3	.1013E+12	24	94.09
L3	37.4	.1022E+12	25	90.33
R3	37.1	.1169E+12	26	98.47
S3	35.6	.1371E+12	29	99.16
L4	35.5	.1480E+12	30	98.25
S4	34.4	.1779E+12	33	100.00
L5	34.3	.1873E+12	33	99.93
R5	34.2	.2004E+12	35	100.00
S5	34.2	.2065E+12	35	100.00
S6	33.7	.2410E+12	38	100.00
SQ	36.3	.4919E+12	54	100.00
R4	30.6	.7000E+12	65	100.00

MDU GAS 396 POWER OPERATED EQUIPMENT
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 396 - POWER OPERATED EQUIPMENT
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 39 INTERVAL: 0 OBSERVATION BAND: 1963 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O3	5.3	.1371E+14	331	100.00
L0	4.6	.1458E+14	341	100.00
L0.5	4.5	.1464E+14	342	100.00
L1	4.4	.1470E+14	342	100.00
SC	4.2	.1471E+14	343	100.00
L1.5	4.4	.1477E+14	343	100.00
R1	4.2	.1482E+14	344	100.00
L2	4.3	.1484E+14	344	100.00
S0.5	4.3	.1485E+14	344	100.00
S1	4.3	.1491E+14	345	100.00
R1.5	4.3	.1493E+14	345	100.00
S1.5	4.3	.1497E+14	346	100.00
S0	4.2	.1498E+14	346	100.00
L3	4.3	.1502E+14	346	100.00
R2.5	4.3	.1507E+14	347	100.00
L4	4.2	.1516E+14	348	100.00
S2	4.4	.1524E+14	349	100.00
R4	4.2	.1526E+14	349	100.00
L5	4.2	.1527E+14	349	100.00
S4	3.9	.1528E+14	349	100.00
S5	4.2	.1531E+14	350	100.00
R5	4.1	.1532E+14	350	100.00
R0.5	4.8	.1538E+14	350	100.00
S-.5	4.8	.1540E+14	350	100.00
R3	4.5	.1568E+14	354	100.00
R2	4.6	.1572E+14	354	100.00
O2	5.3	.1584E+14	356	100.00
S6	3.4	.1629E+14	360	100.00
S3	4.7	.1657E+14	364	100.00
O4	7.6	.2304E+14	429	100.00
SQ	3.4	.2647E+14	460	100.00

MDU GAS 397 COMMUNICATIONS EQUIPMENT
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 397 - COMMUNICATION EQUIPMENT
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 71 INTERVAL: 0 OBSERVATION BAND: 1931 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	82.6	.1884E+12	94	63.82
O3	63.0	.1961E+12	96	67.97
O2	46.2	.2138E+12	100	79.87
SC	41.4	.2154E+12	100	85.18
R0.5	37.9	.2495E+12	108	95.95
L0	42.1	.2659E+12	111	84.42
S-.5	38.1	.2682E+12	112	95.01
R1	34.9	.2965E+12	118	19.58
L0.5	39.2	.3068E+12	120	89.83
S0	35.5	.3377E+12	126	99.95
R1.5	34.4	.3457E+12	127	100.00
L1	36.8	.3587E+12	129	94.29
S0.5	34.6	.3834E+12	134	100.00
R2	32.0	.4060E+12	138	100.00
L1.5	35.5	.4103E+12	138	96.65
S1	33.8	.4391E+12	143	100.00
R2.5	31.9	.4607E+12	147	100.00
L2	34.0	.4757E+12	149	98.65
S1.5	32.9	.4816E+12	150	100.00
R3	31.4	.5271E+12	157	100.00
S2	32.1	.5342E+12	158	100.00
L3	32.5	.5870E+12	166	99.97
S3	31.0	.6292E+12	172	100.00
R4	30.9	.6347E+12	172	100.00
L4	31.3	.6834E+12	179	100.00
S4	30.8	.7364E+12	186	100.00
R5	31.4	.7846E+12	192	100.00
L5	31.2	.7928E+12	193	100.00
S5	31.0	.8405E+12	198	100.00
S6	31.8	.9452E+12	210	100.00
SQ	34.2	.1291E+13	246	100.00

MDU COMMON 389 LAND AND LAND RIGHTS
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 389 - LAND AND LAND RIGHTS
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 50 INTERVAL: 0 OBSERVATION BAND: 1952 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
R3	42.3	.1716E+11	25	70.98
L2	51.3	.1802E+11	26	52.66
R2.5	46.8	.1811E+11	26	52.90
S1.5	47.4	.1814E+11	26	54.57
S1	52.0	.1850E+11	26	45.69
L1.5	58.5	.1855E+11	26	42.52
S2	44.2	.1914E+11	27	64.14
L1	67.3	.1971E+11	27	35.64
S0.5	59.2	.1980E+11	27	36.97
L3	43.4	.1980E+11	27	70.71
R2	52.8	.2045E+11	28	39.71
R4	38.2	.2098E+11	28	94.80
S0	68.9	.2145E+11	28	30.81
L0.5	81.9	.2234E+11	29	28.82
S3	39.9	.2244E+11	29	83.00
L4	38.8	.2335E+11	30	87.47
L0	100.8	.2411E+11	30	24.71
R1.5	64.3	.2415E+11	30	28.57
S-.5	93.2	.2596E+11	31	22.89
R1	79.9	.2650E+11	31	23.06
S4	37.2	.2808E+11	32	97.30
R0.5	104.3	.2816E+11	32	19.98
L5	36.7	.2842E+11	33	96.89
R5	36.2	.2850E+11	33	14.22
O2	147.3	.2890E+11	33	18.85
SC	131.2	.2891E+11	33	18.87
O3	214.6	.2906E+11	33	18.63
O4	292.8	.2914E+11	33	18.50
S5	35.9	.3141E+11	34	99.96
S6	35.0	.3240E+11	35	100.00
SQ	36.2	.9948E+11	61	100.00

MDU COMMON 390 STRUCTURES AND IMPROVEMENTS
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 391 - STRUCTURES AND IMPROVEMENTS
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 50 INTERVAL: 0 OBSERVATION BAND: 1952 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
R5	29.6	.7671E+13	52	100.00
S6	29.9	.8021E+13	53	100.00
L4	30.9	.8032E+13	53	98.78
R4	29.7	.8040E+13	53	100.00
S3	31.2	.8116E+13	53	99.46
L5	29.9	.8281E+13	54	99.97
S4	29.8	.8298E+13	54	100.00
S2	33.1	.8309E+13	54	94.27
R3	32.5	.8416E+13	54	98.98
L3	33.6	.8449E+13	54	90.01
S1.5	35.2	.8675E+13	55	86.43
L2	37.9	.8847E+13	55	77.09
R2.5	35.0	.8990E+13	56	91.47
S1	37.9	.9044E+13	56	76.36
L1.5	41.9	.9349E+13	57	67.61
R2	37.9	.9651E+13	58	78.19
S0.5	41.5	.9701E+13	58	65.25
L1	46.9	.9777E+13	58	58.04
S0	46.8	.1027E+14	60	53.98
L0.5	54.5	.1054E+14	61	49.05
R1.5	42.8	.1061E+14	61	60.93
L0	65.0	.1107E+14	62	41.36
R1	50.3	.1135E+14	63	45.96
S-.5	58.7	.1139E+14	63	40.65
S5	31.8	.1154E+14	63	100.00
R0.5	62.4	.1191E+14	64	36.27
O2	86.4	.1217E+14	65	32.13
SC	77.1	.1217E+14	65	32.11
O3	125.9	.1224E+14	65	30.88
O4	171.8	.1228E+14	65	30.27
SQ	32.2	.1313E+14	68	100.00

MDU COMMON 391 - OFFICE FURNITURE, COMPUTER EQUIPMENT
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 391 - OFFICE FURNITURE, COMPUTER EQUIPMENT
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 50 INTERVAL: 0 OBSERVATION BAND: 1952 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
S0	12.2	.2208E+14	174	100.00
L1	12.5	.2231E+14	175	100.00
S-.5	12.3	.2233E+14	175	100.00
R0.5	12.3	.2249E+14	175	100.00
L0.5	12.8	.2251E+14	176	100.00
R1	12.1	.2253E+14	176	100.00
L1.5	12.4	.2303E+14	178	100.00
L0	13.3	.2314E+14	178	100.00
S0.5	12.3	.2337E+14	179	100.00
SC	12.7	.2350E+14	179	100.00
L2	12.1	.2394E+14	181	100.00
O2	13.8	.2414E+14	182	100.00
R1.5	12.3	.2425E+14	182	100.00
S1	12.4	.2545E+14	187	100.00
R2	12.2	.2637E+14	190	100.00
O3	17.2	.2647E+14	190	93.34
L3	11.8	.2760E+14	194	100.00
O4	21.5	.2795E+14	196	85.55
R2.5	11.8	.2825E+14	197	100.00
S1.5	12.5	.2830E+14	197	100.00
S2	11.0	.3018E+14	203	100.00
R3	11.7	.3126E+14	207	100.00
L4	11.5	.3331E+14	214	100.00
R4	11.6	.3471E+14	218	100.00
S5	11.2	.3647E+14	224	100.00
S4	11.5	.3773E+14	227	100.00
L5	11.5	.3797E+14	228	100.00
R5	11.4	.3808E+14	228	100.00
S6	11.2	.4200E+14	240	100.00
S3	12.8	.4232E+14	241	100.00
SQ	12.2	.5162E+14	266	100.00

MDU COMMON 397 COMMUNICATIONS EQUIPMENT
SIMULATED PLANT-RECORD ANALYSIS (v. F1.00)
ACCOUNT: 397 - COMMUNICATION EQUIPMNET - COMMON
SIMULATED BALANCES METHOD

NO. OF TEST POINTS: 50 INTERVAL: 0 OBSERVATION BAND: 1952 - 2001

DISPERSION	AVERAGE SERVICE LIFE	SUM OF SQUARED DIFFERENCES	INDEX OF VARIATION	RETIREMENT EXPERIENCE INDEX
O4	54.0	.1567E+12	47	65.81
O3	41.2	.1704E+12	49	70.45
O2	30.8	.2078E+12	54	82.24
SC	27.6	.2134E+12	55	89.78
L0	28.0	.2509E+12	59	87.00
R0.5	25.8	.2760E+12	62	97.86
S-.5	25.7	.2817E+12	63	97.88
L0.5	26.3	.3011E+12	65	91.67
R1	24.2	.3562E+12	71	100.00
L1	25.0	.3597E+12	71	95.43
S0	23.7	.3607E+12	71	100.00
L1.5	23.9	.4233E+12	77	97.69
S0.5	23.3	.4308E+12	78	100.00
R1.5	23.4	.4335E+12	78	100.00
L2	23.1	.4932E+12	84	99.11
S1	22.7	.5015E+12	84	100.00
R2	22.3	.5125E+12	85	100.00
S1.5	22.4	.5483E+12	88	100.00
R2.5	22.0	.5843E+12	91	100.00
S2	21.8	.6132E+12	93	100.00
L3	22.1	.6168E+12	93	99.99
R3	21.7	.6302E+12	94	100.00
S3	21.3	.7090E+12	100	100.00
L4	21.3	.7234E+12	101	100.00
R4	21.1	.7383E+12	102	100.00
L5	20.8	.7418E+12	103	100.00
S5	20.6	.7745E+12	105	100.00
S4	21.0	.7746E+12	105	100.00
S6	20.5	.8159E+12	108	100.00
R5	22.5	.1076E+13	124	100.00
SQ	22.4	.1146E+13	128	100.00

SIMULATED PLANT-RECORD SURVIVOR ANALYSIS SUMMARY

Gas Division

- MDU GAS 374 RIGHTS OF WAY
- MDU GAS 375 STRUCTURES AND IMPROVEMENT
- MDU GAS 376 DISTRIBUTION MAINS
- MDU GAS 378 MEAS AND REG STATION EQUIP - GENERAL
- MDU GAS 379 MEAS AND REG STATION EQUIP - CITY GATE
- MDU GAS 380 SERVICES
- MDU GAS 381 METERS
- MDU GAS 383 HOUSE REGULATORS
- MDU GAS 385 INDUSTRIAL MEAS. AND REG STATION EQUIOPMENT
- MDU GAS 387 CATHODIC PROTECTION AND OTHER DISTRIBUTION
- MDU GAS 391 OFFICE FURNITURE, EQUIPMENT AND COMPUTER
- MDU GAS 393 STORES EQUIPMENT
- MDU GAS 394 TOOLS, SHOP AND GARAGE EQUIP.
- MDU GAS 396 POWER OPERATED EQUIPMENT
- MDU GAS 397 COMMUNICATIONS EQUIPMENT

Common Division

- MDU COMMON 389 LAND AND LAND RIGHTS
- MDU COMMON 390 STRUCTURES AND IMPROVEMENTS
- MDU COMMON 391 OFFICE FURNITURE, COMPUTER EQUIPMENT
- MDU COMMON 397 COMMUNICATIONS EQUIPMENT

ACTUARIAL ANALYSIS SUMMARY

Gas Division

- MDU GAS 376 DISTRIBUTION MAINS
- MDU GAS 378 MEAS AND REG STATION EQUIP - GENERAL
- MDU GAS 379 MEAS AND REG STATION EQUIP - CITY GATE
- MDU GAS 380 SERVICES
- MDU GAS 387 CATHODIC PROTECTION AND OTHER DISTRIBUTION
- MDU GAS 391 OFFICE FURNITURE, EQUIPMENT AND COMPUTER
- MDU GAS 394 TOOLS, SHOP AND GARAGE EQUIPMENT
- MDU GAS 396 POWER OPERATED EQUIPMENT
- MDU GAS 397 COMMUNICATIONS EQUIPMENT

Each study includes:

- Observed Life Table Results
- Curve Results with Analytical Parameters
- 3 Best Fit Curve Graphs with Analytical Parameters
- Actuarial Analysis Data

MDU GAS 376 MAINS
ACTUARIAL ANALYSIS
ACCOUNT: 376 - MAINS

OBSERVED LIFE TABLE RESULTS

Full Band: 1977-2001

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	55,191,196.34	-2,810.42	0.0051	99.9949	1.0000
1.5	53,328,541.11	-33,898.63	0.0636	99.9364	0.9999
2.5	51,437,696.21	-51,253.84	0.0996	99.9004	0.9993
3.5	49,846,344.69	-35,545.73	0.0713	99.9287	0.9983
4.5	48,050,345.98	-68,999.92	0.1436	99.8564	0.9976
5.5	45,869,710.08	-72,037.81	0.1570	99.8430	0.9962
6.5	43,282,287.52	-49,860.64	0.1152	99.8848	0.9946
7.5	41,879,156.83	-29,858.39	0.0713	99.9287	0.9935
8.5	36,821,648.11	-55,842.36	0.1517	99.8483	0.9928
9.5	28,561,444.17	-22,258.20	0.0779	99.9221	0.9912
10.5	25,989,649.76	-89,111.72	0.3429	99.6571	0.9905
11.5	24,127,509.96	-10,759.29	0.0446	99.9554	0.9871
12.5	22,747,529.45	-83,599.72	0.3675	99.6325	0.9866
13.5	21,613,627.34	-23,158.71	0.1071	99.8929	0.9830
14.5	20,248,063.24	-63,697.40	0.3146	99.6854	0.9820
15.5	18,425,522.00	-52,290.63	0.2838	99.7162	0.9789
16.5	15,921,442.99	-16,122.14	0.1013	99.8987	0.9761
17.5	13,779,259.79	-35,168.53	0.2552	99.7448	0.9751
18.5	12,169,112.08	-32,916.03	0.2705	99.7295	0.9726
19.5	10,142,281.50	-29,329.31	0.2892	99.7108	0.9700
20.5	7,771,493.39	-11,540.50	0.1485	99.8515	0.9672
21.5	5,643,043.77	-2,427.33	0.0430	99.9570	0.9657
22.5	3,359,979.61	-1,094.33	0.0326	99.9674	0.9653
23.5	1,607,496.63	-724.08	0.0450	99.9550	0.9650
24.5	691,189.71	-1,419.14	0.2053	99.7947	0.9646

Account: 376

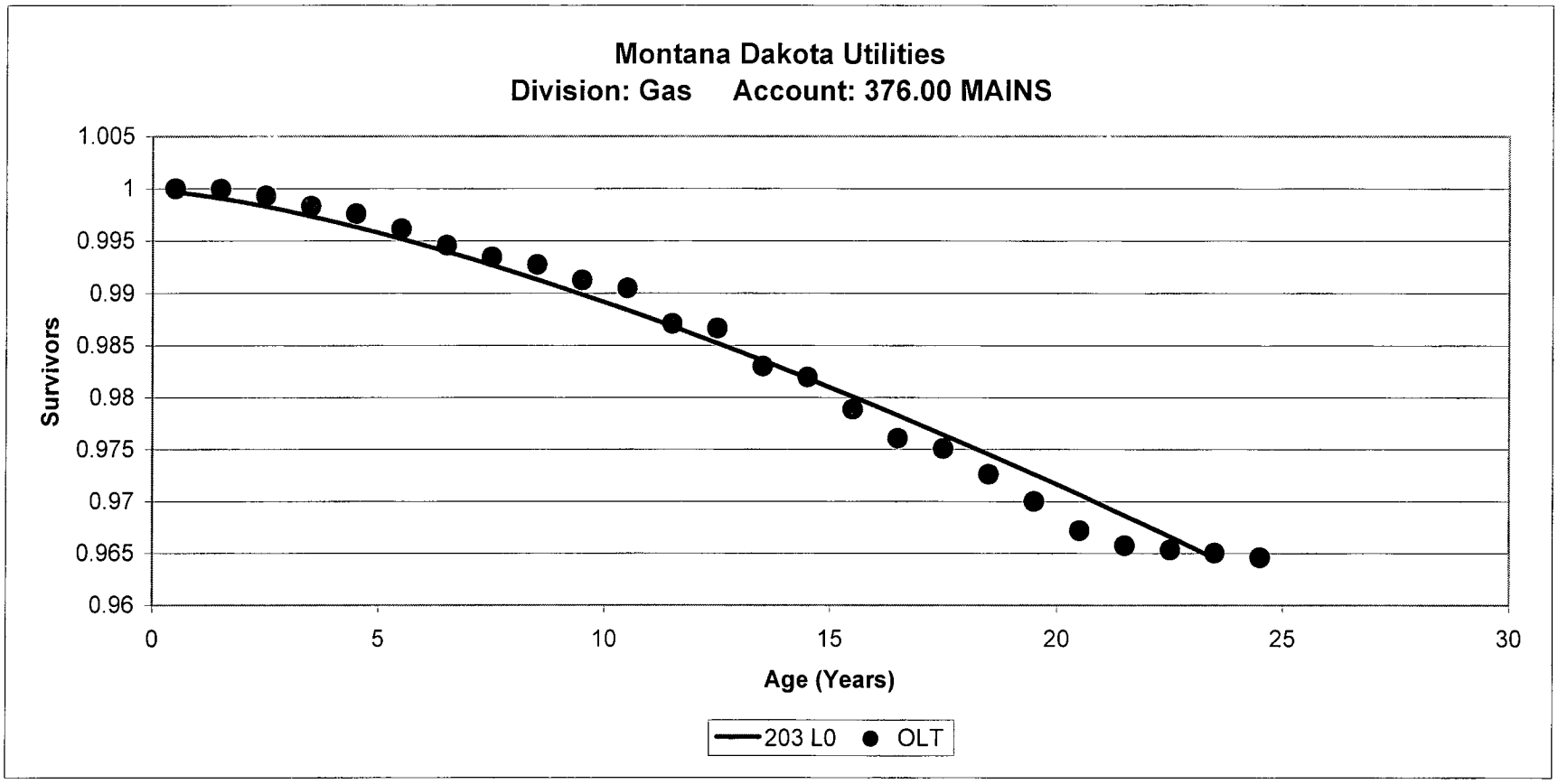
MDU GAS 376 MAINS
ACTUARIAL ANALYSIS
ACCOUNT: 376 - MAINS

CURVE RESULTS

Curve Name	Curve Age	Sum of Squared Differences
L0	203	9,119.99
L0.5	153	9,120.09
R2	96	9,120.34
R2.5	71	9,120.59
S-0.5	222	9,120.61
S0	118	9,120.66
R1.5	146	9,120.68
R1	202	9,120.88
L1	103	9,121.03
R0.5	285	9,121.06
S0.5	92	9,121.56
L1.5	82	9,122.41
R3	53	9,124.23
O1	300	9,125.85
S1	69	9,126.36
L2	63	9,126.85
S1.5	59	9,128.52
O2	300	9,133.82
L3	46	9,137.02
S2	49	9,137.36
R4	39	9,139.80
S3	40	9,151.40
L4	37	9,154.92
R5	31	9,170.16
S4	33	9,170.84
L5	32	9,175.10
S5	30	9,188.14
S6	28	9,201.88
SQ	25	9,204.63
O3	300	9,212.44
O4	300	9,406.52

Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 300
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

MDU GAS 376 MAINS ACTUARIAL ANALYSIS ACCOUNT: 376 - MAINS



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
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Life Expectancy Increment: 1
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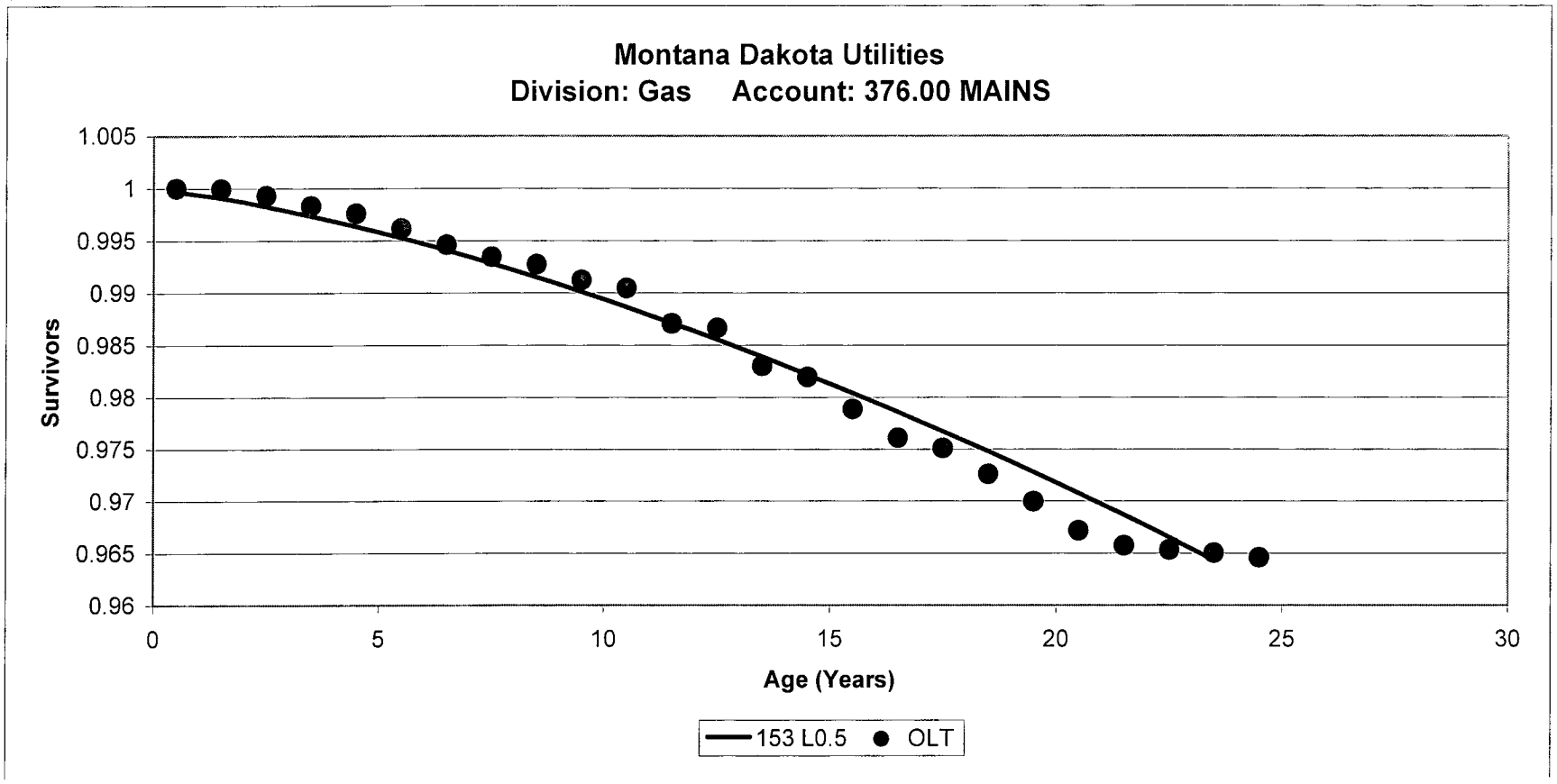
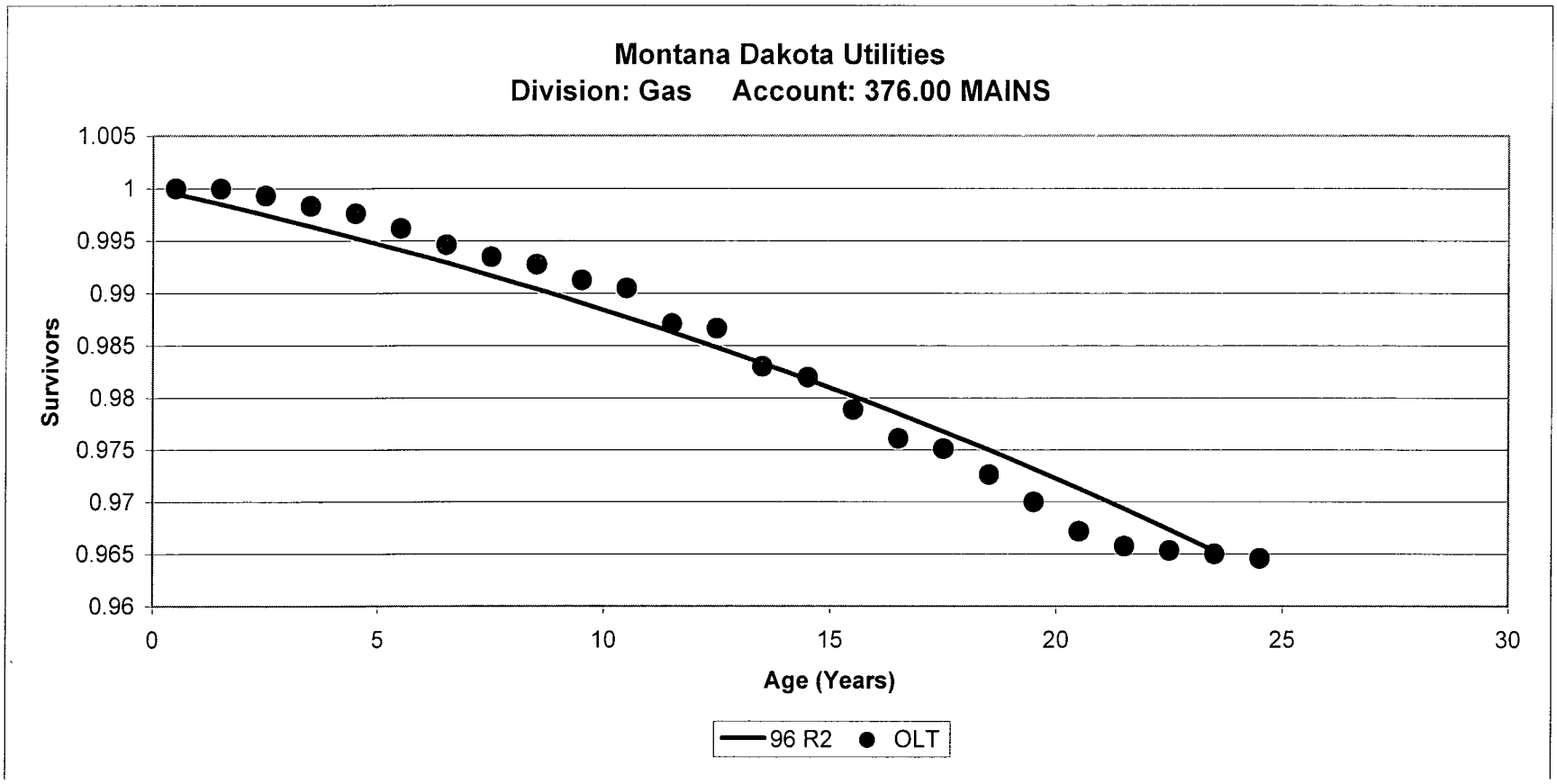
Montana Dakota Utilities



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 300
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

Montana Dakota Utilities



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 300
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

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MDU GAS 376 MAINS ACTUARIAL ANALYSIS ACCOUNT 376 - MAINS

Age	L0	L0 5	L1	L1 5	L2	L3	L4	L5	O1	O2	O3	O4	R0 5	R1	R1 5	R2	R2 5	R3	R4	R5	S0	S0 5	S-0 5	S1	S1 5	S2	S3	S4	S5	S6	SQ
0.5	0 999689	0 999699	0 999718	0 999823	0 999999	1	1	1	0 999167	0 999065	0 998618	0 998068	0 999335	0 999361	0 999396	0 999506	0 999611	0 999854	0 999989	1	0 999911	0 999942	0 999414	0 999999	0 999999	1	1	1	1	1	1
1.5	0 999068	0 999097	0 999124	0 999437	0 999982	1	1	1	0 9975	0 997195	0 995854	0 994203	0 998005	0 998083	0 998186	0 9985	0 998806	0 999525	0 99996	1	0 999656	0 999732	0 998241	0 999976	0 999981	1	1	1	1	1	1
2.5	0.9983	0 998273	0 998464	0 998989	0 999926	1	1	1	0 995833	0 995324	0 99309	0 990338	0 996675	0 996797	0 996954	0 997457	0 997949	0 999141	0 999918	1	0 999205	0 999362	0 997049	0 999903	0 999925	0 999998	1	1	1	1	1
3.5	0 997366	0 997371	0 997733	0 998461	0 999799	1	1	1	0 994167	0 993454	0 990328	0 986478	0 995341	0 995502	0 995707	0 996378	0 997047	0 998695	0 999859	1	0 998587	0 998849	0 99581	0 999759	0 99981	0 999988	1	1	1	1	1
4.5	0 996341	0 996377	0 996927	0 997851	0 999585	0 999998	1	1	0 9925	0 991583	0 987568	0 982624	0 994004	0 994198	0 994448	0 995261	0 996086	0 99818	0 999775	1	0 9978	0 998201	0 994569	0 99951	0 999614	0 999961	1	1	1	1	1
5.5	0 995199	0 995262	0 99604	0 99715	0 999254	0 999977	1	1	0 990833	0 989712	0 984807	0 97877	0 992668	0 992884	0 993167	0 994105	0 99507	0 997587	0 999658	1	0 996881	0 997422	0 993278	0 999156	0 999324	0 999904	0 999997	1	1	1	1
6.5	0 99399	0 994089	0 99507	0 996349	0 998791	0 999907	1	1	0 989167	0 98784	0 982049	0 974922	0 991327	0 991562	0 99187	0 992908	0 993997	0 996906	0 999499	1	0 995835	0 996504	0 991987	0 998651	0 998924	0 999797	0 999992	1	1	1	1
7.5	0 992683	0 992841	0 99401	0 995429	0 998179	0 999755	1	1	0 9875	0 985969	0 979292	0 971079	0 989984	0 99023	0 99056	0 99167	0 992858	0 99613	0 999283	1	0 99467	0 995457	0 990658	0 998007	0 998383	0 999615	0 999976	1	1	1	1
8.5	0 991324	0 991501	0 992857	0 994385	0 997389	0 999482	1	1	0 985833	0 984098	0 976535	0 967236	0 988641	0 988891	0 98923	0 990391	0 991658	0 995247	0 998993	1	0 99339	0 994282	0 98932	0 997186	0 997696	0 999331	0 999942	1	1	1	1
9.5	0 989878	0 990112	0 991605	0 993214	0 996426	0 999052	0 999998	1	0 984167	0 982226	0 973781	0 963399	0 987292	0 987541	0 987881	0 989068	0 990382	0 994243	0 998608	1	0 991998	0 992978	0 987957	0 99619	0 996846	0 998909	0 999871	1	1	1	1
10.5	0 988391	0 988654	0 990251	0 991909	0 995252	0 998426	0 999981	1	0 9825	0 980355	0 971028	0 959568	0 985943	0 986184	0 986519	0 9877	0 989037	0 993106	0 998104	1	0 990485	0 991547	0 986577	0 994997	0 995804	0 998314	0 999739	0 999998	1	1	1
11.5	0 986824	0 98712	0 98879	0 990461	0 993872	0 997566	0 999909	1	0 980833	0 976483	0 968275	0 955737	0 984593	0 984816	0 985139	0 986286	0 987615	0 991826	0 997443	0 999999	0 988861	0 989989	0 985181	0 993596	0 994557	0 997502	0 999509	0 999992	1	1	1
12.5	0 985223	0 985541	0 987218	0 988845	0 99227	0 996424	0 99971	1	0 979167	0 976611	0 965525	0 951913	0 983238	0 983441	0 983736	0 984826	0 986109	0 990389	0 996598	0 99999	0 987138	0 988301	0 983761	0 991985	0 993095	0 996429	0 999131	0 999975	1	1	1
13.5	0 983549	0 983893	0 98553	0 987072	0 990428	0 994975	0 999285	1	0 9775	0 974739	0 962777	0 948096	0 981882	0 982056	0 98232	0 983316	0 984525	0 988782	0 99551	0 999949	0 985318	0 986485	0 982335	0 990132	0 99139	0 99505	0 99854	0 999923	1	1	1
14.5	0 981846	0 98218	0 983723	0 985139	0 988359	0 993185	0 998513	0 999998	0 975833	0 972866	0 960028	0 944278	0 980525	0 980664	0 980887	0 981756	0 982842	0 98699	0 994138	0 999824	0 983404	0 98454	0 980877	0 988064	0 989417	0 993313	0 997651	0 999792	1	1	1
15.5	0 980074	0 980425	0 981792	0 983038	0 986018	0 991023	0 997243	0 999971	0 974167	0 970994	0 957282	0 940467	0 979163	0 97926	0 97943	0 980146	0 981073	0 984996	0 992412	0 99951	0 981398	0 982466	0 979419	0 985724	0 987176	0 99117	0 996366	0 9995	0 999997	1	1
16.5	0 978279	0 9786	0 979735	0 980752	0 983437	0 988456	0 995301	0 999804	0 9725	0 969122	0 954538	0 936664	0 977801	0 97785	0 977959	0 978484	0 979202	0 982786	0 990262	0 998823	0 9793	0 980262	0 977927	0 983156	0 984645	0 988569	0 994564	0 998898	0 99998	1	1
17.5	0 976418	0 976719	0 977545	0 978275	0 980589	0 985444	0 992533	0 999227	0 970833	0 967249	0 951794	0 93286	0 976437	0 976428	0 976473	0 97677	0 977229	0 980343	0 987611	0 997506	0 977097	0 977927	0 976432	0 980309	0 981781	0 985459	0 992112	0 997751	0 999909	1	1
18.5	0 974538	0 974798	0 975218	0 975618	0 977473	0 981935	0 988773	0 997789	0 969167	0 965377	0 949052	0 929064	0 975068	0 975	0 97496	0 975	0 975153	0 977641	0 98435	0 995205	0 974809	0 975454	0 974913	0 977211	0 978595	0 981791	0 988854	0 995715	0 999662	0 999999	1
19.5	0 972595	0 972804	0 972753	0 972776	0 974101	0 977888	0 983804	0 994882	0 9675	0 963504	0 946313	0 925275	0 9737	0 973561	0 973433	0 973175	0 972955	0 974667	0 980407	0 99147	0 972439	0 972852	0 973385	0 973835	0 975073	0 977515	0 984628	0 992313	0 998933	0 999986	1
20.5	0 970637	0 97076	0 970148	0 969746	0 970435	0 973233	0 977513	0 989783	0 965833	0 961631	0 943574	0 921486	0 972328	0 972116	0 97189	0 971293	0 970649	0 971405	0 975614	0 985733	0 969987	0 970116	0 971839	0 970186	0 971165	0 972584	0 979258	0 98693	0 996998	0 999872	1
21.5	0 968619	0 968678	0 967399	0 966497	0 966494	0 967881	0 96976	0 981757	0 964167	0 959758	0 940837	0 917706	0 970953	0 970658	0 970321	0 969352	0 968214	0 967835	0 969902	0 977351	0 967454	0 967256	0 970277	0 966264	0 966881	0 966954	0 972565	0 978821	0 992591	0 999149	1
22.5	0 966588	0 966521	0 964505	0 963055	0 962205	0 961723	0 960367	0 970157	0 9625	0 957885	0 938103	0 913933	0 969578	0 969196	0 968736	0 967352	0 965651	0 963937	0 963093	0 965566	0 964844	0 964262	0 968706	0 962049	0 962213	0 960582	0 964367	0 967141	0 983643	0 995741	1
23.5	0 964498	0 964319	0 961464	0 959419	0 957533	0 954605	0 949203	0 954386	0 960833	0 956012	0 935368	0 91016	0 968199	0 96772	0 967134	0 965291	0 96296	0 959691	0 955068	0 949366	0 962148	0 961138	0 967113	0 957568	0 957124	0 953431	0 954489	0 950998	0 966908	0 983676	1
24.5	0 906396	0 906396	0 906396	0 906396	0 906396	0 906396	0 906396	0 906396					0 906396	0 906396	0 906396	0 906396	0 906396	0 906396			0 906396	0 906396	0 906396	0 906396	0 906396	0 906396	0 906396	0 906396	0 906396	0 906396	0 906396

Account 376

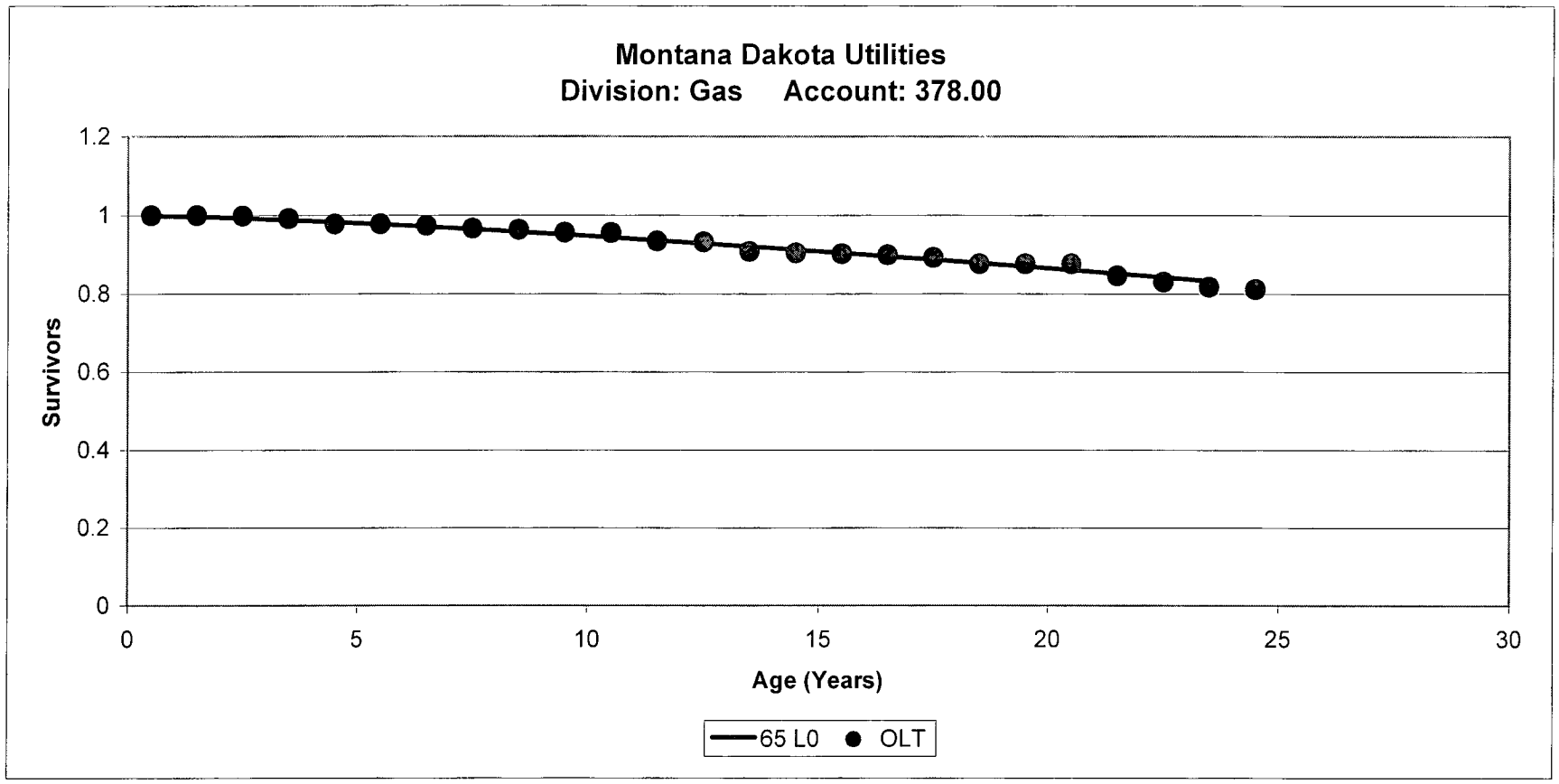
Full Band: 1977-2001

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	898,010.78	0.00	0.0000	100.0000	1.0000
1.5	880,908.22	-1,100.99	0.1250	99.8750	1.0000
2.5	853,495.98	-6,048.43	0.7087	99.2913	0.9988
3.5	821,626.38	-11,363.01	1.3830	98.6170	0.9917
4.5	769,322.84	0.00	0.0000	100.0000	0.9780
5.5	704,463.06	-2,583.93	0.3668	99.6332	0.9780
6.5	678,017.59	-5,320.33	0.7847	99.2153	0.9744
7.5	659,128.69	-1,903.33	0.2888	99.7112	0.9667
8.5	583,331.47	-4,375.82	0.7501	99.2499	0.9639
9.5	460,106.87	-572.08	0.1243	99.8757	0.9567
10.5	421,076.16	-9,257.41	2.1985	97.8015	0.9555
11.5	400,241.74	-981.72	0.2453	99.7547	0.9345
12.5	393,889.98	-10,126.17	2.5708	97.4292	0.9322
13.5	350,724.61	-1,592.28	0.4540	99.5460	0.9082
14.5	307,262.58	-693.27	0.2256	99.7744	0.9041
15.5	282,998.72	-969.51	0.3426	99.6574	0.9021
16.5	266,954.06	-1,930.81	0.7233	99.2767	0.8990
17.5	236,457.92	-4,271.06	1.8063	98.1937	0.8925
18.5	207,474.58	0.00	0.0000	100.0000	0.8764
19.5	164,158.58	0.00	0.0000	100.0000	0.8764
20.5	120,567.62	-4,183.24	3.4696	96.5304	0.8764
21.5	110,034.47	-2,125.13	1.9313	98.0687	0.8460
22.5	54,324.55	-795.68	1.4647	98.5353	0.8296
23.5	44,764.15	-320.65	0.7163	99.2837	0.8175
24.5	21,187.83	-535.68	2.5282	97.4718	0.8116

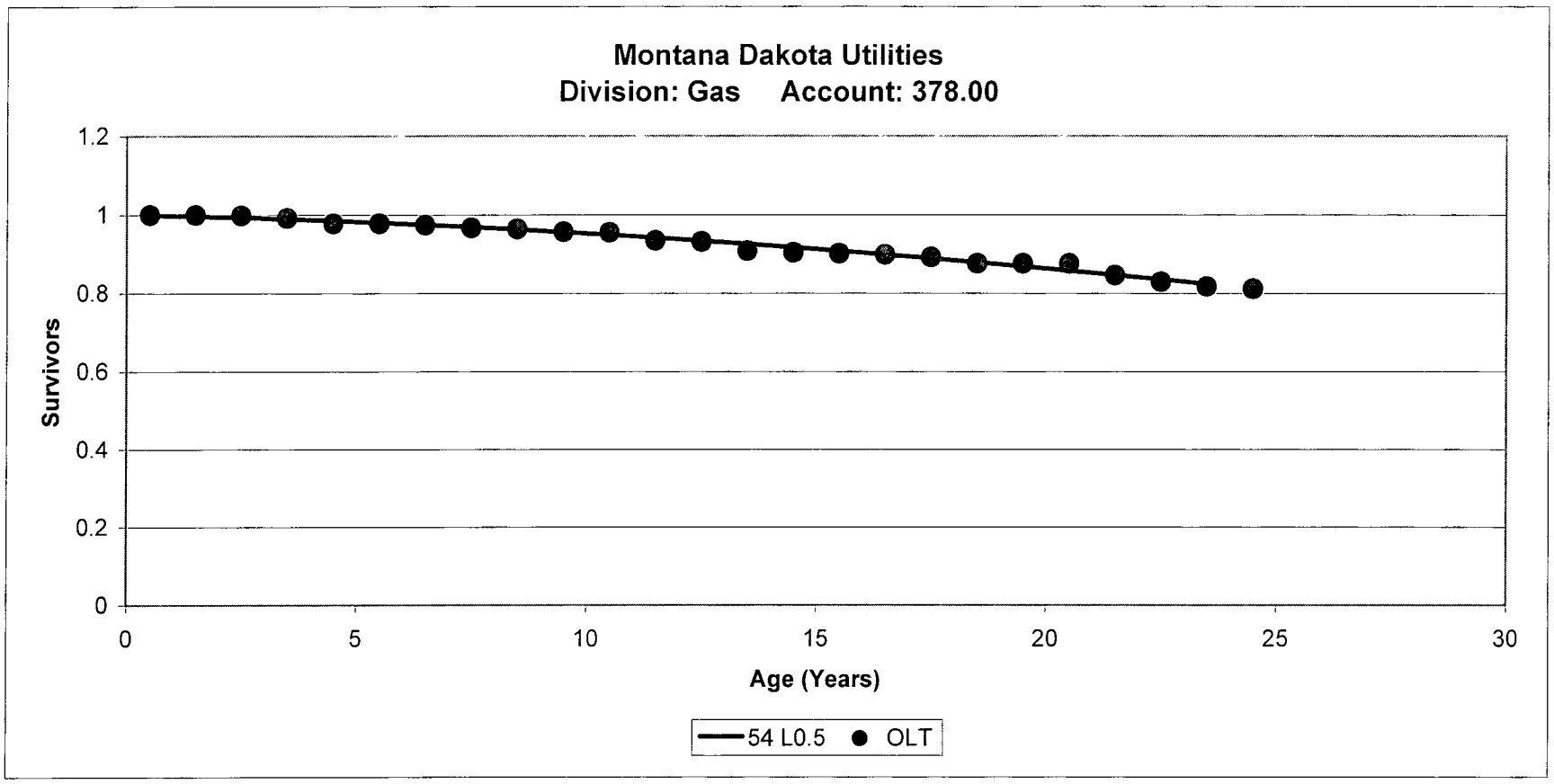
Account: 378

Curve Name	Curve Age	Least Sum of Squares
L0	65	6,467.56
L0.5	54	6,468.31
R1.5	41	6,469.69
S0	46	6,472.43
S-0.5	58	6,475.20
R1	50	6,478.61
R2	36	6,479.86
R0.5	63	6,491.22
S0.5	41	6,492.40
L1	46	6,496.10
O2	87	6,498.45
O1	78	6,498.54
O3	128	6,500.24
O4	178	6,501.05
R2.5	32	6,513.92
L1.5	41	6,526.67
S1	36	6,552.29
S1.5	34	6,604.70
R3	30	6,605.90
L2	36	6,618.26
S2	31	6,715.92
L3	31	6,796.38
R4	27	6,843.77
S3	29	6,924.45
L4	28	6,987.83
S4	27	7,229.09
R5	26	7,284.16
L5	26	7,299.00
S5	26	7,547.64
S6	25	7,803.17
SQ	25	8,403.19

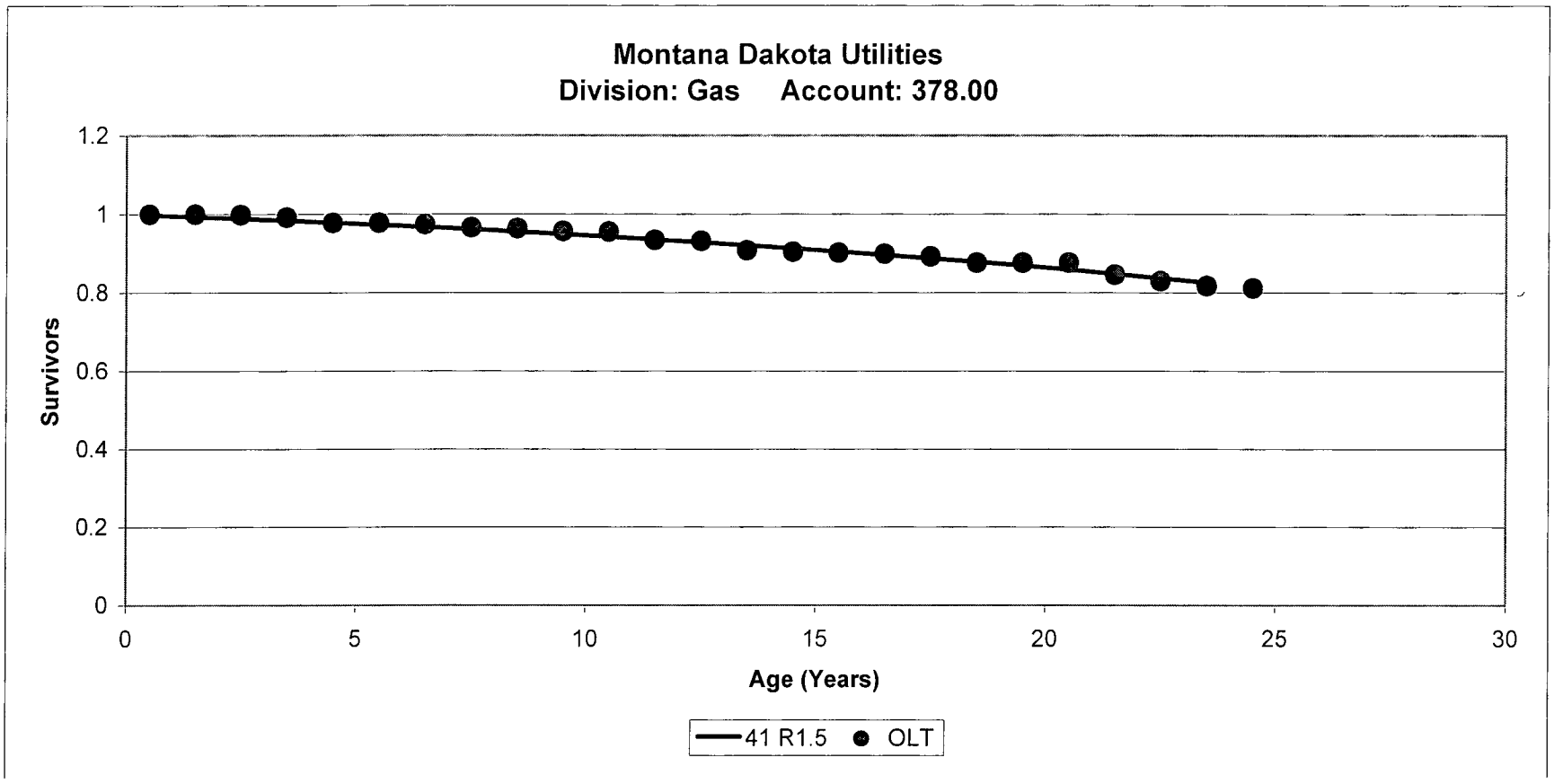
Account: 378
Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

Age	L0	L0.5	L1	L1.5	L2	L3	L4	L5	O1	O2	O3	O4	R0.5	R1	R1.5	R2	R2.5	R3	R4	R5	S0	S0.5	S0.5	S1	S1.5	S2	S3	S4	S5	S6	SQ
0.5	0.99903	0.999147	0.999364	0.999637	0.999996	1	1	1	0.996795	0.996775	0.996761	0.996743	0.996991	0.997419	0.99784	0.99867	0.999125	0.999733	0.999963	1	0.999748	0.999838	0.997755	0.999992	0.999995	1	1	1	1	1	1
1.5	0.99613	0.996626	0.997843	0.998733	0.999914	1	1	1	0.990385	0.990324	0.990285	0.990229	0.990943	0.992148	0.993371	0.995825	0.997204	0.99908	0.999934	1	0.998318	0.998922	0.992967	0.999859	0.999916	0.999998	1	1	1	1	1
2.5	0.992281	0.993361	0.995948	0.997517	0.999619	1	1	1	0.983974	0.983872	0.983815	0.983728	0.984851	0.986731	0.988691	0.992707	0.995022	0.998226	0.99985	1	0.995932	0.997324	0.987861	0.999423	0.999652	0.999979	1	1	1	1	1
3.5	0.987716	0.989505	0.99363	0.995898	0.998982	0.999986	1	1	0.977564	0.977418	0.977354	0.977233	0.978709	0.981169	0.983788	0.989289	0.992548	0.997132	0.999716	1	0.992728	0.995051	0.982485	0.998531	0.999108	0.999901	0.999999	1	1	1	1
4.5	0.982621	0.985129	0.990837	0.993826	0.997901	0.999886	1	1	0.971154	0.970962	0.970899	0.970755	0.972524	0.975461	0.978665	0.985557	0.989742	0.995748	0.999499	1	0.988789	0.99215	0.976845	0.99707	0.998189	0.999696	0.999994	1	1	1	1
5.5	0.977019	0.980273	0.987522	0.991196	0.996286	0.999591	1	1	0.964744	0.964505	0.964451	0.964281	0.966292	0.969609	0.973301	0.981489	0.988566	0.994005	0.999164	1	0.984176	0.988577	0.970977	0.994941	0.996802	0.999262	0.999974	1	1	1	1
6.5	0.971041	0.974964	0.983618	0.987984	0.994063	0.998979	1	1	0.958333	0.958046	0.958011	0.957825	0.960016	0.963612	0.967703	0.977052	0.982977	0.991848	0.998857	1	0.978919	0.984371	0.964901	0.992059	0.994855	0.998471	0.999914	1	1	1	1
7.5	0.964659	0.969204	0.979092	0.984107	0.99115	0.997912	0.999695	1	0.951923	0.951587	0.95158	0.951377	0.953694	0.957471	0.961855	0.972243	0.97893	0.989207	0.997902	1	0.973067	0.979499	0.958619	0.98833	0.992251	0.997156	0.999765	1	1	1	1
8.5	0.95798	0.963014	0.973908	0.979535	0.987504	0.996274	0.999936	1	0.945513	0.945128	0.945157	0.944943	0.947325	0.951187	0.955753	0.967013	0.974373	0.985986	0.996802	1	0.966662	0.973975	0.952138	0.983705	0.988895	0.995149	0.999439	0.999999	1	1	1
9.5	0.950982	0.956409	0.96803	0.974225	0.983091	0.99395	0.999695	1	0.939103	0.938667	0.938743	0.938523	0.940914	0.944761	0.949389	0.961347	0.969255	0.982114	0.995234	0.999999	0.959733	0.967794	0.945479	0.978138	0.984683	0.992262	0.998805	0.999991	1	1	1
10.5	0.943731	0.949393	0.96143	0.968136	0.977882	0.990835	0.999043	1	0.932692	0.932206	0.932338	0.932112	0.934454	0.938194	0.942751	0.955219	0.963516	0.977502	0.993033	0.999989	0.952305	0.960944	0.938648	0.971591	0.979527	0.988298	0.99767	0.999962	1	1	1
11.5	0.936223	0.941974	0.954085	0.961276	0.971849	0.986812	0.997693	1	0.926282	0.925745	0.925941	0.925722	0.927951	0.931486	0.935842	0.948596	0.957098	0.972025	0.989992	0.999933	0.944403	0.953452	0.931644	0.964025	0.973336	0.983046	0.995779	0.999864	1	1	1
12.5	0.928496	0.934155	0.945949	0.953584	0.964924	0.981749	0.99526	0.999979	0.919872	0.919284	0.919556	0.919338	0.921404	0.92464	0.928636	0.941439	0.949828	0.965604	0.985879	0.999728	0.936033	0.945282	0.924478	0.955403	0.966022	0.976302	0.992822	0.999583	1	1	1
13.5	0.920561	0.925945	0.937041	0.945112	0.956917	0.975491	0.991376	0.999769	0.913462	0.912822	0.913181	0.912979	0.914811	0.917655	0.921141	0.93373	0.941941	0.95813	0.980407	0.999161	0.927233	0.936482	0.917162	0.945733	0.957508	0.967899	0.988394	0.998898	0.999996	1	1
14.5	0.912433	0.917333	0.927362	0.935778	0.947553	0.96779	0.98563	0.998855	0.907051	0.90636	0.906816	0.906628	0.908176	0.910534	0.913324	0.925434	0.93307	0.949453	0.973198	0.997856	0.918022	0.927018	0.909701	0.935006	0.94772	0.957669	0.982116	0.997382	0.999971	1	1
15.5	0.904135	0.908343	0.916921	0.925557	0.936573	0.9583	0.977639	0.996322	0.900641	0.899897	0.900462	0.900298	0.901495	0.903277	0.905187	0.916519	0.923239	0.939483	0.963904	0.99526	0.908418	0.916929	0.902088	0.923226	0.936596	0.945468	0.973442	0.99439	0.999846	1	1
16.5	0.895669	0.898986	0.905731	0.914352	0.92373	0.946515	0.967091	0.990941	0.894231	0.893435	0.89412	0.893983	0.894772	0.895882	0.896702	0.906935	0.912373	0.928094	0.952106	0.99062	0.898439	0.906209	0.894341	0.910376	0.924087	0.931124	0.961994	0.988988	0.999357	0.999999	1
17.5	0.887063	0.88927	0.893813	0.902109	0.908915	0.931944	0.953602	0.98137	0.887621	0.886973	0.88779	0.887684	0.888004	0.888345	0.887854	0.896656	0.900391	0.915095	0.937312	0.983006	0.888099	0.894872	0.886464	0.896484	0.910151	0.914591	0.947225	0.979879	0.99778	0.999983	1
18.5	0.878313	0.879212	0.881186	0.888806	0.892095	0.914046	0.936888	0.966368	0.88141	0.88051	0.881473	0.881407	0.881195	0.880651	0.878629	0.885647	0.887206	0.900383	0.919067	0.971278	0.877406	0.88294	0.878458	0.881578	0.894764	0.895807	0.928792	0.965561	0.993521	0.999806	1
19.5	0.869449	0.868821	0.867913	0.874396	0.873296	0.892333	0.916275	0.944791	0.875	0.874047	0.875167	0.875139	0.874344	0.872824	0.868994	0.873872	0.872729	0.883792	0.896946	0.953945	0.866389	0.870405	0.870326	0.865684	0.877912	0.874748	0.906306	0.944471	0.983643	0.998507	1
20.5	0.860461	0.858114	0.854042	0.85896	0.852596	0.866404	0.890865	0.91482	0.86859	0.867585	0.868872	0.868903	0.867447	0.864826	0.858952	0.861286	0.856856	0.865078	0.870513	0.928817	0.855058	0.857318	0.862077	0.848822	0.859598	0.851393	0.879534	0.915038	0.96349	0.991983	1
21.5	0.851379	0.847101	0.839629	0.842467	0.830122	0.836136	0.859087	0.87307	0.862179	0.861122	0.862596	0.862674	0.860507	0.856661	0.848449	0.847838	0.839483	0.8441	0.839368	0.893174	0.843431	0.843651	0.853716	0.831016	0.839836	0.825796	0.848377	0.875907	0.927503	0.968574	1
22.5	0.842199	0.835814	0.824736	0.825066	0.806106	0.801701	0.819046	0.81445	0.855769	0.854659	0.856333	0.856477	0.853521	0.84832	0.837501	0.833506	0.820514	0.82065	0.803355	0.843807	0.83152	0.829466	0.84524	0.812325	0.818665	0.798059	0.81279	0.826564	0.870346	0.906927	1
23.5	0.832941	0.824274	0.809425	0.806802	0.780768	0.763495	0.76927	0.734985	0.849359	0.848196	0.850083	0.850294	0.846488	0.839796	0.826059	0.818251	0.799838	0.79442	0.762059	0.777788	0.819335	0.814752	0.836659	0.792792	0.796125	0.768298	0.773038	0.767089	0.788991	0.785414	1
24.5	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784

Account 378

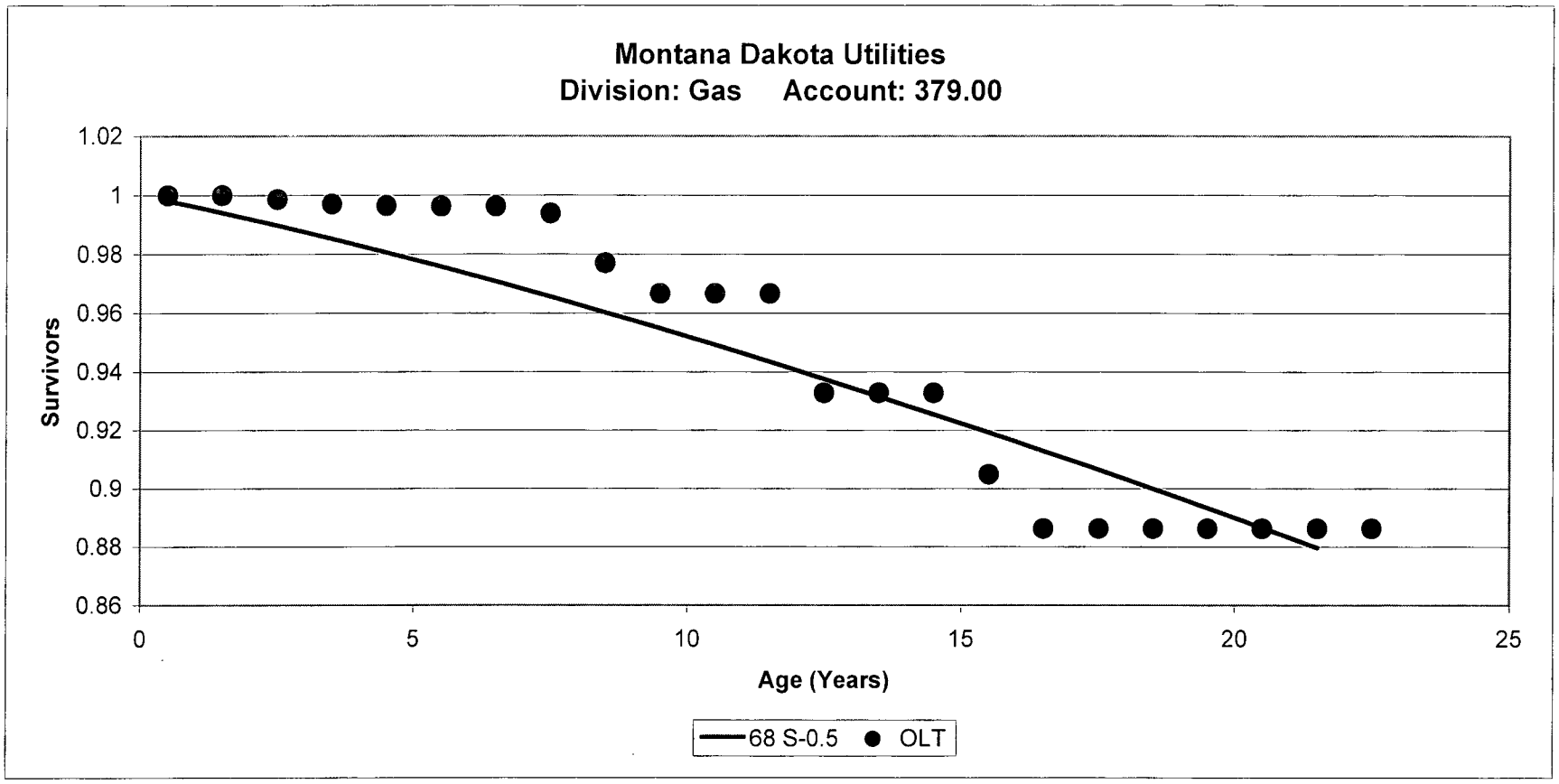
Full Band: 1977-1999

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	872,928.98	0.00	0.0000	100.0000	1.0000
1.5	872,286.95	-1,169.44	0.1341	99.8659	1.0000
2.5	866,558.96	-1,429.24	0.1649	99.8351	0.9987
3.5	863,403.45	-451.56	0.0523	99.9477	0.9970
4.5	854,837.04	-240.01	0.0281	99.9719	0.9965
5.5	729,710.03	0.00	0.0000	100.0000	0.9962
6.5	515,272.28	-1,202.10	0.2333	99.7667	0.9962
7.5	139,345.91	-2,362.99	1.6958	98.3042	0.9939
8.5	136,982.92	-1,458.39	1.0647	98.9353	0.9770
9.5	134,620.52	0.00	0.0000	100.0000	0.9666
10.5	132,905.16	0.00	0.0000	100.0000	0.9666
11.5	132,905.16	-4,651.15	3.4996	96.5004	0.9666
12.5	128,254.01	0.00	0.0000	100.0000	0.9328
13.5	130,441.64	0.00	0.0000	100.0000	0.9328
14.5	129,993.41	-3,882.92	2.9870	97.0130	0.9328
15.5	126,110.49	-2,593.97	2.0569	97.9431	0.9049
16.5	118,026.16	0.00	0.0000	100.0000	0.8863
17.5	109,494.34	0.00	0.0000	100.0000	0.8863
18.5	90,261.76	0.00	0.0000	100.0000	0.8863
19.5	73,848.81	0.00	0.0000	100.0000	0.8863
20.5	33,703.49	0.00	0.0000	100.0000	0.8863
21.5	27,508.53	0.00	0.0000	100.0000	0.8863
22.5	3,307.27	0.00	0.0000	100.0000	0.8863

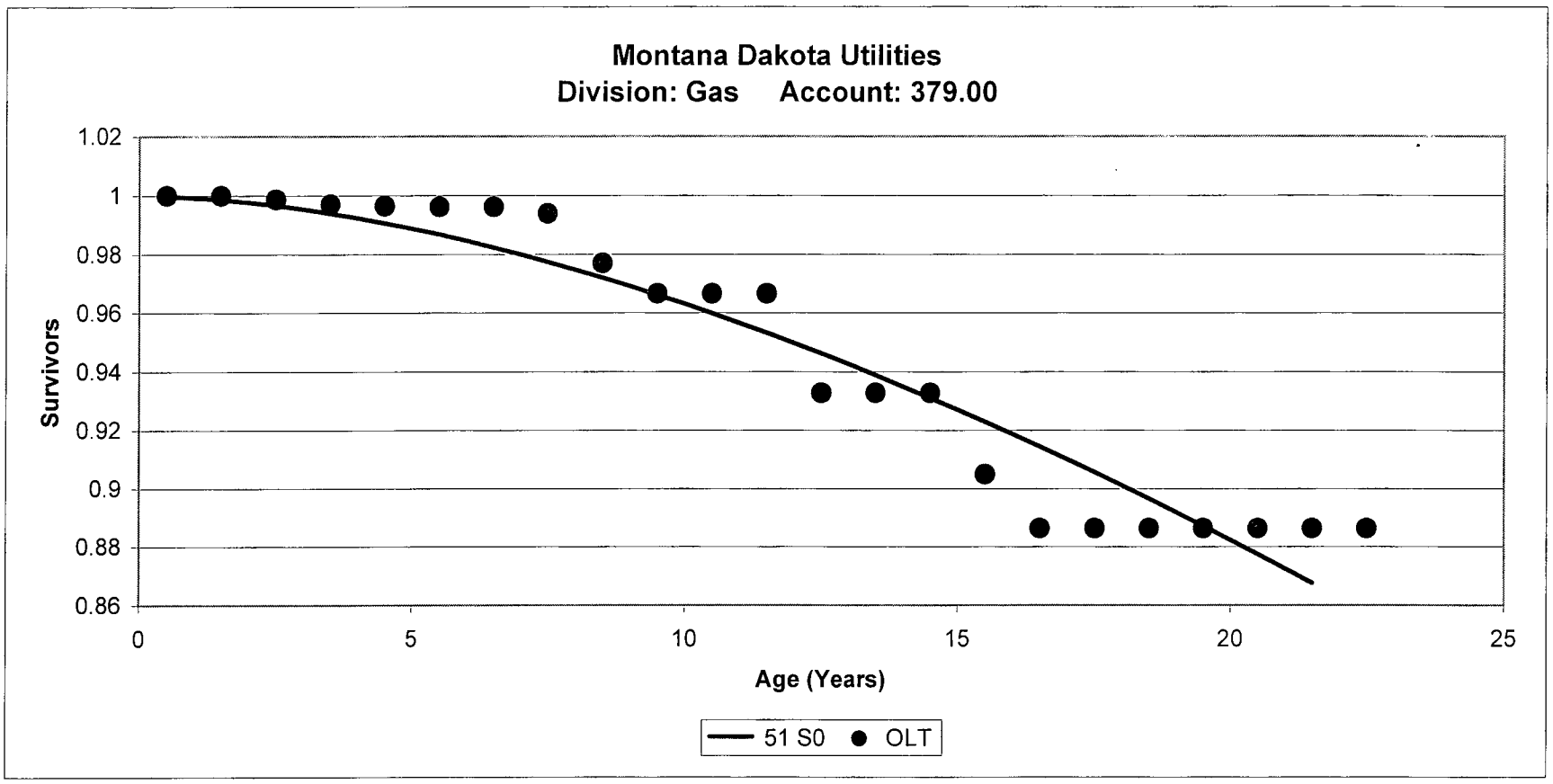
Account: 379

Curve Name	Curve Age	Least Sum of Squares
S-0.5	68	7,755.00
S0	51	7,735.34
S0.5	43	7,741.68
S1	38	7,768.48
S1.5	34	7,797.69
S2	31	7,865.59
S3	28	8,001.08
S4	26	8,207.99
S5	24	8,395.98
S6	23	8,555.82
SQ	23	8,720.18
L0	74	7,741.24
L0.5	60	7,739.35
L1	49	7,745.63
L1.5	42	7,757.72
L2	37	7,806.88
L3	31	7,913.07
L4	27	8,029.91
L5	25	8,238.13
R0.5	77	7,769.37
R1	59	7,760.25
R1.5	47	7,751.81
R2	38	7,745.62
R2.5	33	7,757.01
R3	30	7,798.07
R4	27	7,946.56
R5	25	8,231.46
O1	97	7,773.72
O2	109	7,773.63
O3	160	7,774.51
O4	200	7,786.47

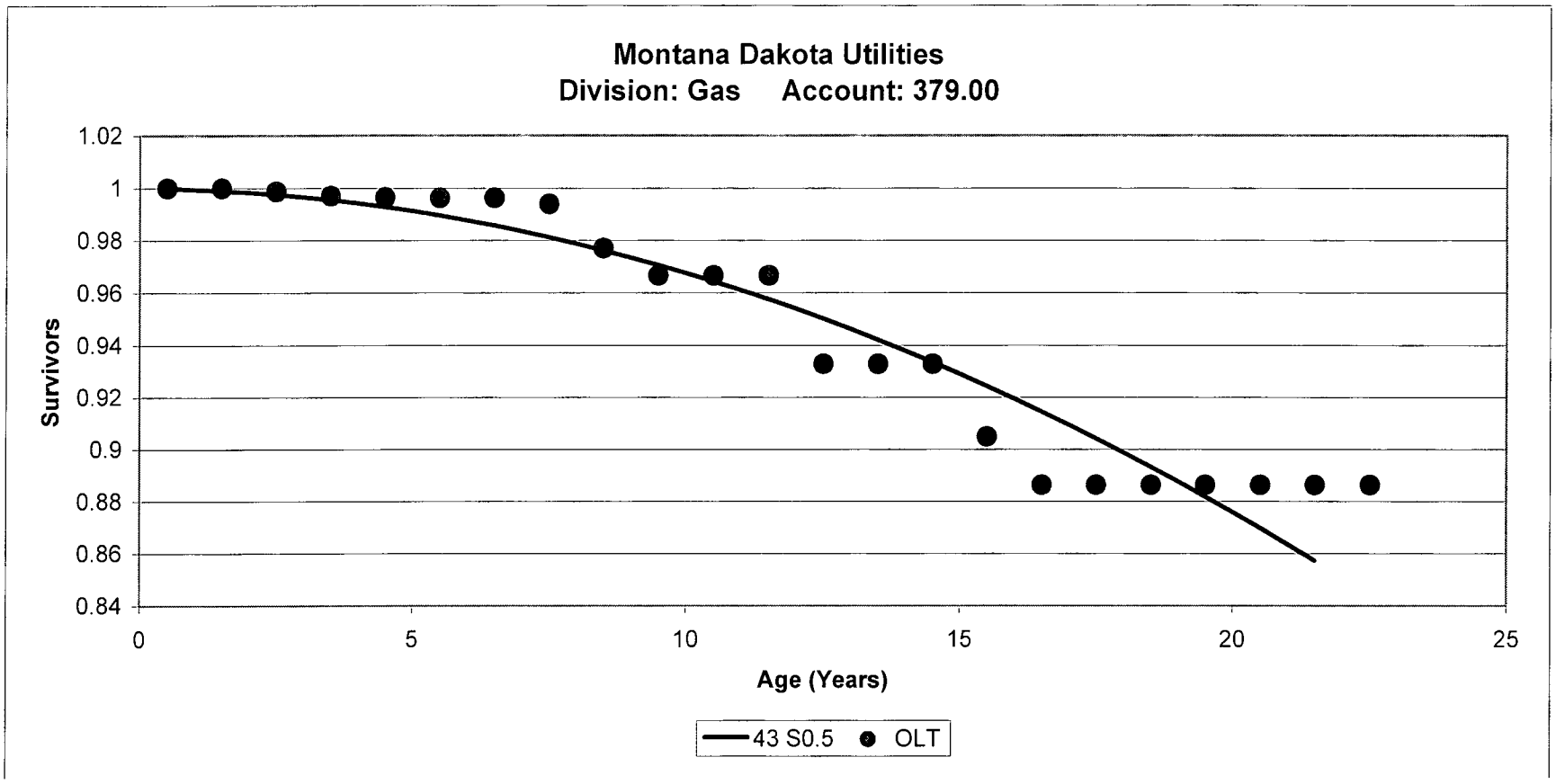
Account: 379
Analytical Parameters
OLT Observation Band: 1977 - 1999
OLT Retirement Band: 1977 - 1999
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 23 (22.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 23 (22.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 23 (22.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 23 (22.5)

Age	L0	L0.5	L1	L1.5	L2	L3	L4	L5	O1	O2	O3	O4	R0.5	R1	R1.5	R2	R2.5	R3	R4	R5	S0	S0.5	S0.5	S1	S1.5	S2	S3	S4	S5	S6	SQ
0.5	0.999148	0.999233	0.999407	0.999647	0.999996	1	1	1	0.997423	0.997426	0.997409	0.997101	0.997538	0.997813	0.99812	0.998742	0.999152	0.999733	0.999983	1	0.999795	0.999852	0.998085	0.999993	0.999995	1	1	1	1	1	1
1.5	0.99678	0.997648	0.998002	0.998769	0.999921	1	1	1	0.992268	0.992278	0.992226	0.991304	0.992599	0.993363	0.994244	0.996061	0.997296	0.99908	0.999934	1	0.998605	0.999008	0.994056	0.999681	0.999916	0.999998	1	1	1	1	1
2.5	0.993522	0.994245	0.996271	0.997602	0.999646	1	1	1	0.987113	0.987128	0.98705	0.985515	0.987625	0.988811	0.990206	0.993131	0.995196	0.998226	0.99985	1	0.996509	0.997541	0.989773	0.999498	0.999652	0.999979	1	1	1	1	1
3.5	0.989732	0.990925	0.994171	0.99605	0.999058	0.999986	1	1	0.981959	0.981977	0.981876	0.979734	0.982621	0.984155	0.986005	0.989942	0.992823	0.997132	0.999716	1	0.993924	0.995471	0.985285	0.998735	0.999108	0.999901	0.999999	1	1	1	1
4.5	0.985483	0.987159	0.991659	0.994066	0.998062	0.999886	1	1	0.976804	0.976826	0.976708	0.973961	0.977589	0.97939	0.981634	0.986473	0.990143	0.995748	0.999499	1	0.990618	0.992801	0.980598	0.997478	0.998189	0.999696	0.999993	1	1	1	1
5.5	0.980805	0.983005	0.988695	0.99158	0.996567	0.999591	1	1	0.971649	0.971672	0.971544	0.968196	0.972524	0.974525	0.977089	0.982702	0.987121	0.994005	0.999164	1	0.986742	0.989554	0.975745	0.995631	0.996802	0.999262	0.999967	1	1	1	1
6.5	0.975802	0.978463	0.985237	0.988517	0.994494	0.998979	1	1	0.966495	0.966519	0.966384	0.962441	0.967428	0.969558	0.972367	0.978619	0.983719	0.991848	0.998657	1	0.982332	0.985715	0.970714	0.993136	0.994855	0.998471	0.99989	1	1	1	1
7.5	0.970487	0.973552	0.981247	0.984854	0.991794	0.997912	0.999988	1	0.96134	0.961364	0.961231	0.956695	0.962304	0.964481	0.967461	0.974191	0.979893	0.989207	0.997902	1	0.977421	0.981269	0.965541	0.989901	0.992251	0.997156	0.9997	1	1	1	1
8.5	0.964879	0.968301	0.976691	0.98052	0.988418	0.996274	0.999888	1	0.956186	0.956209	0.956082	0.950959	0.957149	0.959303	0.962365	0.969404	0.9756	0.985986	0.996802	1	0.972037	0.976239	0.960203	0.985886	0.988895	0.995149	0.999286	0.999997	1	1	1
9.5	0.959035	0.962697	0.971535	0.975487	0.984301	0.99395	0.999526	1	0.951031	0.951054	0.950937	0.945232	0.951961	0.954026	0.957073	0.964244	0.970791	0.982114	0.995234	0.999998	0.966204	0.970611	0.954738	0.981058	0.984683	0.992262	0.99849	0.999985	1	1	1
10.5	0.95295	0.956748	0.965754	0.969746	0.979439	0.990835	0.998623	1	0.945876	0.945898	0.945799	0.939516	0.946744	0.948642	0.951583	0.958664	0.965414	0.977502	0.993033	0.999976	0.959943	0.964369	0.949124	0.975331	0.979527	0.988298	0.997063	0.999935	1	1	1
11.5	0.946648	0.950477	0.959324	0.963224	0.973814	0.986812	0.996805	0.999997	0.940722	0.940742	0.940666	0.933811	0.941499	0.943156	0.945891	0.952662	0.959415	0.972025	0.989992	0.999868	0.953274	0.957539	0.943391	0.968722	0.973336	0.983046	0.994719	0.999772	1	1	1
12.5	0.940163	0.943872	0.952227	0.955958	0.967371	0.981749	0.993667	0.999921	0.935567	0.935585	0.935539	0.928117	0.936219	0.937572	0.93999	0.946209	0.952734	0.965604	0.985879	0.99951	0.948215	0.950115	0.937522	0.961194	0.966022	0.976302	0.991046	0.999325	0.999996	1	1
13.5	0.933482	0.936932	0.944452	0.947924	0.95998	0.975491	0.988773	0.999417	0.930412	0.930428	0.930419	0.922434	0.930912	0.931886	0.933875	0.939265	0.945313	0.95813	0.980407	0.998583	0.938782	0.94208	0.931541	0.95271	0.957508	0.967899	0.985625	0.998251	0.999964	1	1
14.5	0.926635	0.929683	0.935992	0.939093	0.95141	0.96779	0.981639	0.997674	0.925258	0.925271	0.925302	0.916763	0.925576	0.926098	0.927541	0.931823	0.937087	0.949453	0.973196	0.996564	0.930992	0.933466	0.925436	0.943296	0.94772	0.957669	0.977944	0.995954	0.999789	1	1
15.5	0.919642	0.922113	0.926849	0.929447	0.941388	0.9583	0.971908	0.993438	0.920103	0.920113	0.920195	0.911104	0.920209	0.920212	0.920979	0.92384	0.927991	0.939483	0.963904	0.992701	0.922858	0.924275	0.919223	0.932916	0.936596	0.945468	0.967473	0.991525	0.999059	0.999997	1
16.5	0.912489	0.914224	0.917031	0.918873	0.929677	0.946515	0.959224	0.985215	0.914948	0.914956	0.915093	0.905457	0.914811	0.914231	0.914174	0.915289	0.917954	0.928094	0.952106	0.986023	0.914396	0.914488	0.912899	0.921583	0.924087	0.931124	0.953733	0.983706	0.996623	0.999947	1
17.5	0.905206	0.906042	0.906549	0.907338	0.91617	0.931944	0.943168	0.971539	0.909794	0.909799	0.909996	0.899824	0.909385	0.908146	0.907122	0.906154	0.906901	0.915095	0.937312	0.975336	0.905617	0.904145	0.906469	0.909323	0.910151	0.914591	0.936151	0.970913	0.989928	0.999403	1
18.5	0.897806	0.897557	0.895424	0.894809	0.900788	0.914046	0.923217	0.951117	0.904639	0.904641	0.90491	0.894204	0.90393	0.901967	0.899811	0.896377	0.894759	0.900383	0.919067	0.959104	0.896536	0.893252	0.899938	0.896106	0.894764	0.895807	0.914426	0.951366	0.974339	0.9956	1
19.5	0.890275	0.888775	0.883685	0.881215	0.883446	0.892333	0.898489	0.922307	0.899485	0.899482	0.899828	0.888597	0.898444	0.895691	0.892229	0.885947	0.881448	0.883792	0.896946	0.935175	0.887165	0.881793	0.893306	0.881985	0.877912	0.874748	0.888119	0.923287	0.943217	0.978453	1
20.5	0.882644	0.879725	0.871364	0.866622	0.864275	0.866404	0.867446	0.881781	0.89433	0.894324	0.894754	0.883005	0.89293	0.889308	0.884365	0.874836	0.866882	0.865078	0.870513	0.900596	0.877513	0.86981	0.886581	0.86698	0.859598	0.851393	0.857152	0.885056	0.889447	0.92463	1
21.5	0.874916	0.870399	0.8585	0.851029	0.843385	0.836136	0.827954	0.824033	0.889175	0.889166	0.889689	0.877427	0.887388	0.882821	0.876206	0.86298	0.850973	0.8441	0.839368	0.851799	0.867595	0.857318	0.879759	0.851083	0.839838	0.825796	0.821444	0.835851	0.807951	0.804501	1
22.5	0.871864	0.871864	0.871864	0.871864	0.871864	0.871864	0.871864	0.871864					0.871864	0.871864	0.871864	0.871864					0.871864	0.871864	0.871864	0.871864	0.871864	0.871864	0.871864	0.871864	0.871864	0.871864	0.871864

Account 379

MDU GAS 380 SERVICES
ACTUARIAL ANALYSIS
ACCOUNT: 380 - SERVICES

OBSERVED LIFE TABLE RESULTS

Full Band: 1977-2001

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	25,538,847.22	-10,400.40	0.0407	99.9593	1.0000
1.5	24,256,974.45	-65,580.64	0.2704	99.7296	0.9996
2.5	23,007,991.79	-61,336.07	0.2666	99.7334	0.9969
3.5	21,893,590.23	-57,786.04	0.2639	99.7361	0.9942
4.5	20,511,679.55	-83,086.45	0.4051	99.5949	0.9916
5.5	18,958,408.44	-62,838.02	0.3315	99.6685	0.9876
6.5	17,485,552.67	-59,463.25	0.3401	99.6599	0.9843
7.5	16,374,165.04	-57,026.74	0.3483	99.6517	0.9810
8.5	13,998,139.68	-52,097.25	0.3722	99.6278	0.9776
9.5	12,884,008.81	-47,671.80	0.3700	99.6300	0.9739
10.5	11,883,309.69	-54,484.07	0.4585	99.5415	0.9703
11.5	11,043,393.97	-43,282.89	0.3919	99.6081	0.9659
12.5	10,404,845.59	-69,164.58	0.6647	99.3353	0.9621
13.5	9,799,166.07	-50,938.08	0.5198	99.4802	0.9557
14.5	9,098,341.62	-74,814.00	0.8223	99.1777	0.9507
15.5	8,379,316.95	-43,460.41	0.5187	99.4813	0.9429
16.5	7,610,366.81	-35,864.87	0.4713	99.5287	0.9380
17.5	6,582,473.35	-39,781.19	0.6044	99.3956	0.9336
18.5	5,626,977.42	-26,441.63	0.4699	99.5301	0.9279
19.5	4,570,065.25	-23,684.18	0.5182	99.4818	0.9236
20.5	3,673,526.65	-17,186.41	0.4678	99.5322	0.9188
21.5	2,845,599.01	-7,409.89	0.2604	99.7396	0.9145
22.5	1,948,098.42	-4,849.09	0.2489	99.7511	0.9121
23.5	1,137,901.98	-4,720.43	0.4148	99.5852	0.9098
24.5	560,530.02	-1,132.32	0.2020	99.7980	0.9061

Account : 380

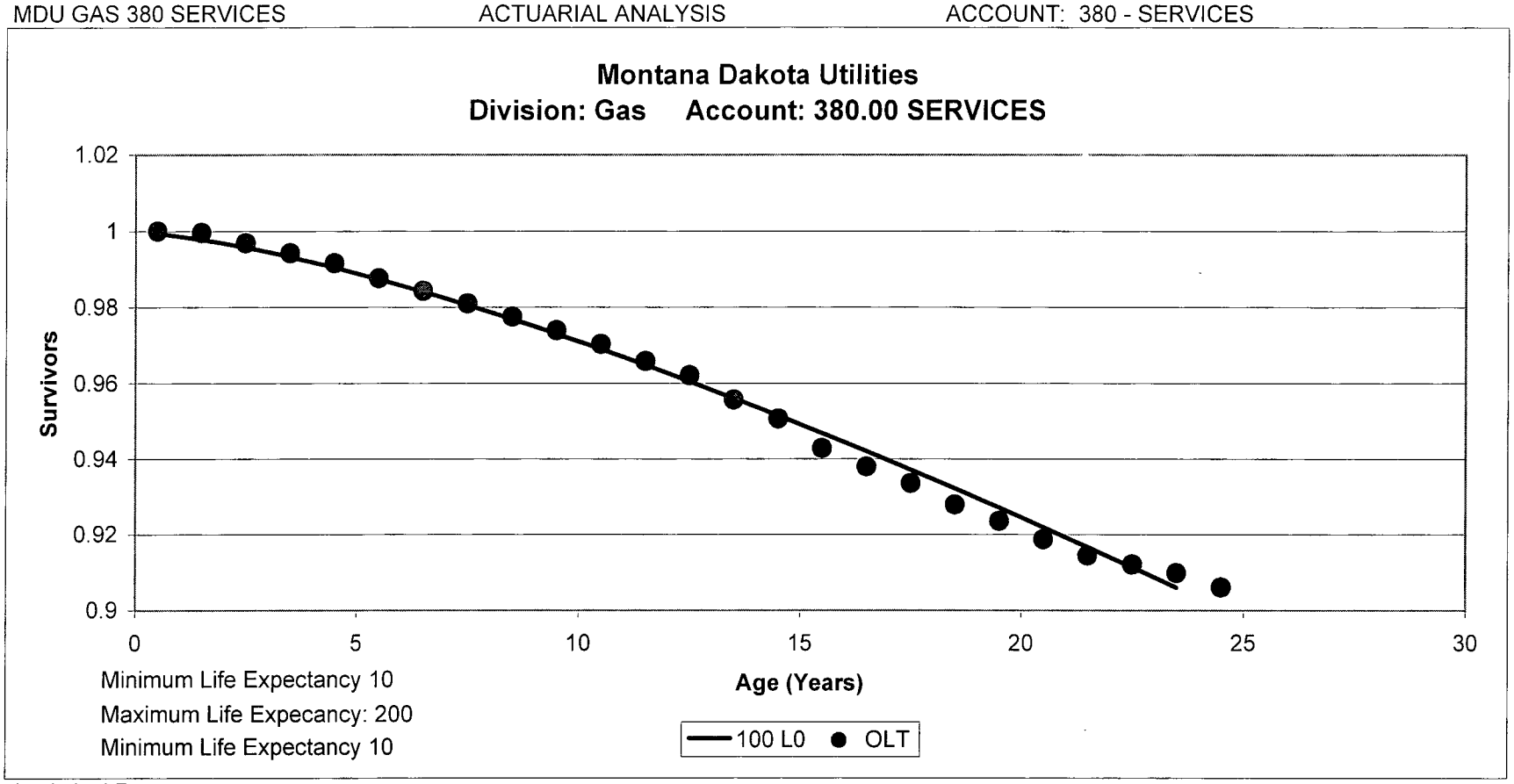
MDU GAS 380 SERVICES
ACTUARIAL ANALYSIS
ACCOUNT: 380 - SERVICES

CURVE RESULTS

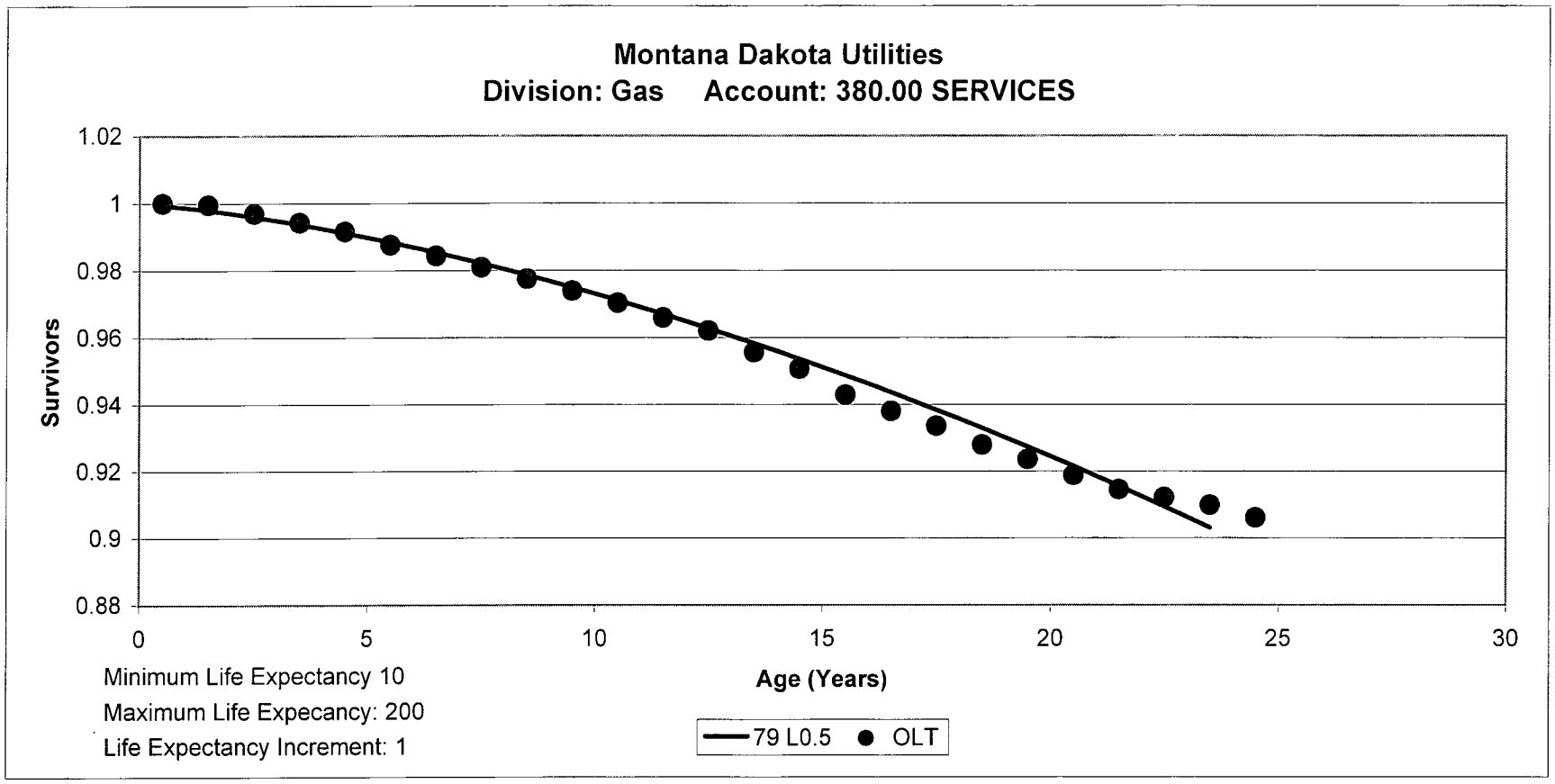
Curve Name	Curve Age	Sum of Squared Differences
L0	100	8,048.51
L0.5	79	8,050.18
R1.5	64	8,050.20
S-0.5	94	8,050.35
R1	82	8,051.69
R2	49	8,052.34
S0	66	8,053.44
R0.5	109	8,053.86
O2	156	8,054.89
O1	139	8,054.92
O3	229	8,055.10
O4	300	8,057.77
S0.5	55	8,061.58
L1	62	8,062.09
R2.5	42	8,062.11
L1.5	53	8,072.32
S1	47	8,088.97
R3	36	8,095.76
L2	45	8,106.35
S1.5	42	8,107.40
S2	38	8,155.25
L3	36	8,171.79
R4	31	8,191.77
S3	33	8,236.83
L4	31	8,248.96
S4	29	8,351.89
R5	28	8,355.26
L5	28	8,369.83
S5	27	8,455.20
S6	26	8,539.68
SQ	25	8,651.85

Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 300
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

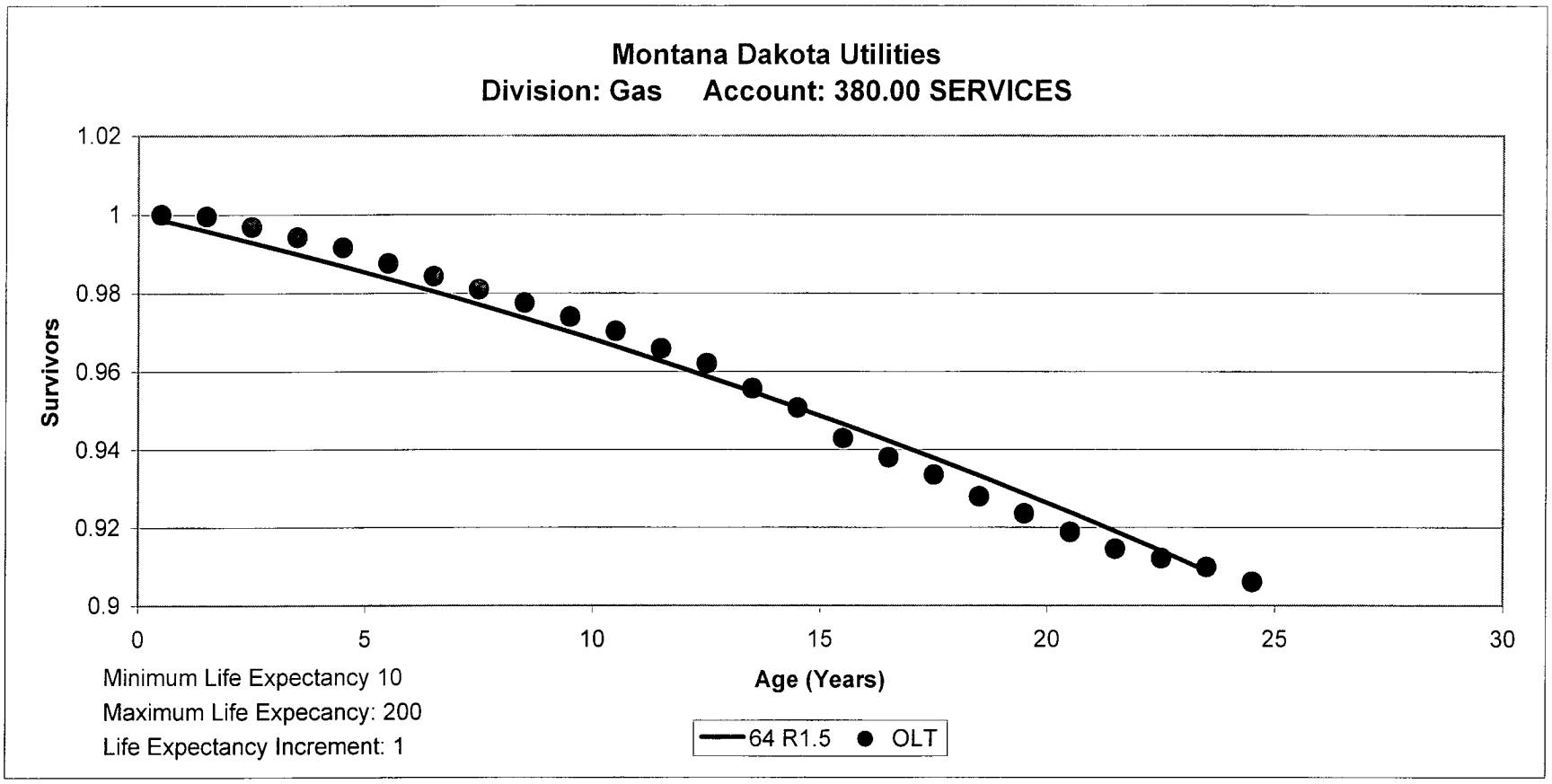
MDU GAS 380 SERVICES ACTUARIAL ANALYSIS ACCOUNT: 380 - SERVICES



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 300
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 300
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 300
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

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DU-399-02-183
Exhibit_____(CWK-3)

MDU GAS 380 SERVICES ACTUARIAL ANALYSIS ACCOUNT 380 - SERVICES

Age	L0	L0.5	L1	L1.5	L2	L3	L4	L5	O1	O2	O3	O4	R0.5	R1	R1.5	R2	R2.5	R3	R4	R5	S0	S0.5	S0.5	S1	S1.5	S2	S3	S4	S5	S6	SQ
0.5	0.99937	0.999417	0.999532	0.999725	0.999998	1	1	1	0.998201	0.998202	0.99819	0.998068	0.998261	0.998426	0.998621	0.999032	0.999338	0.99978	0.999986	1	0.999842	0.999904	0.999615	0.999997	0.999997	1	1	1	1	1	1
1.5	0.997791	0.997937	0.99847	0.999073	0.999954	1	1	1	0.994604	0.994605	0.994569	0.994203	0.994777	0.995249	0.995806	0.996992	0.997918	0.999259	0.999945	1	0.999093	0.999356	0.995756	0.999932	0.999953	0.999999	1	1	1	1	1
2.5	0.995685	0.996004	0.997224	0.998248	0.999799	1	1	1	0.991007	0.991007	0.990949	0.990338	0.991277	0.992017	0.992907	0.994808	0.996356	0.998609	0.999882	1	0.997824	0.998414	0.992756	0.999721	0.999809	0.999992	1	1	1	1	1
3.5	0.9932	0.993741	0.995744	0.997213	0.999467	0.999998	1	1	0.98741	0.987408	0.987332	0.986478	0.987763	0.988726	0.989916	0.992472	0.994629	0.997803	0.999784	1	0.998104	0.997101	0.989633	0.999294	0.999506	0.999961	1	1	1	1	1
4.5	0.990406	0.991209	0.994037	0.995933	0.998901	0.999964	1	1	0.983813	0.98381	0.983716	0.982624	0.984233	0.985383	0.986843	0.989977	0.992733	0.996814	0.999636	1	0.99399	0.995426	0.986401	0.99859	0.999001	0.999878	0.999997	1	1	1	1
5.5	0.987349	0.988433	0.992074	0.994374	0.998034	0.999839	1	1	0.980216	0.980211	0.980105	0.97877	0.980687	0.981988	0.98367	0.987313	0.990648	0.995614	0.999416	1	0.991494	0.993394	0.983066	0.997555	0.998245	0.999699	0.99999	1	1	1	1
6.5	0.98406	0.985395	0.989821	0.992505	0.99683	0.999549	1	1	0.976619	0.976611	0.976493	0.974922	0.977126	0.978541	0.980411	0.984472	0.988351	0.994168	0.999097	1	0.988662	0.990987	0.979636	0.996145	0.997177	0.999373	0.999966	1	1	1	1
7.5	0.980562	0.982136	0.987285	0.990296	0.995252	0.99901	1	1	0.973022	0.97301	0.972885	0.971079	0.973549	0.975035	0.977053	0.981445	0.985834	0.992432	0.998636	1	0.985489	0.988222	0.976115	0.994316	0.995765	0.998822	0.999906	1	1	1	1
8.5	0.976874	0.978669	0.984414	0.98772	0.993262	0.998141	0.999991	1	0.969424	0.96941	0.969279	0.967236	0.969957	0.971476	0.973601	0.978224	0.983059	0.990369	0.997987	1	0.982018	0.985098	0.972503	0.992023	0.993943	0.99797	0.999771	1	1	1	1
9.5	0.973013	0.975	0.981212	0.984743	0.990821	0.996867	0.999926	1	0.965827	0.965809	0.965675	0.963399	0.966349	0.967864	0.970052	0.974797	0.980037	0.987935	0.997086	1	0.978233	0.981615	0.968808	0.989236	0.991665	0.996733	0.999505	0.999997	1	1	1
10.5	0.968992	0.971102	0.977669	0.981348	0.987903	0.995112	0.999701	1	0.96223	0.962207	0.962074	0.959568	0.962728	0.9642	0.966398	0.971156	0.976725	0.985085	0.995855	0.999999	0.97418	0.97777	0.965033	0.985934	0.988895	0.994989	0.999019	0.999987	1	1	1
11.5	0.964822	0.967012	0.973729	0.977519	0.984497	0.992803	0.999149	1	0.958633	0.958605	0.958474	0.955737	0.95909	0.960484	0.962649	0.96729	0.973089	0.981755	0.994189	0.999984	0.969835	0.973554	0.96118	0.98209	0.985545	0.992658	0.998193	0.99995	1	1	1
12.5	0.960514	0.962733	0.969427	0.973241	0.980589	0.989861	0.998047	0.999999	0.955036	0.955003	0.95488	0.951913	0.955437	0.956709	0.958787	0.963188	0.969127	0.97791	0.991966	0.999921	0.965246	0.968964	0.957253	0.977685	0.981603	0.989626	0.996869	0.99984	1	1	1
13.5	0.956075	0.958256	0.964717	0.968501	0.976165	0.986231	0.996139	0.999976	0.951439	0.951401	0.951285	0.948096	0.95177	0.952883	0.954827	0.95884	0.964803	0.973476	0.989044	0.999715	0.960383	0.964011	0.953254	0.9727	0.977005	0.985766	0.994851	0.999551	0.999999	1	1
14.5	0.951515	0.953573	0.959597	0.96329	0.971193	0.981828	0.993145	0.999783	0.947842	0.947799	0.947695	0.944278	0.948087	0.949005	0.950751	0.954234	0.960084	0.968403	0.985257	0.999189	0.955297	0.958696	0.949185	0.967124	0.971693	0.981	0.991904	0.998898	0.999989	1	1
15.5	0.94684	0.948707	0.954085	0.9576	0.965657	0.976547	0.988773	0.999008	0.944245	0.944196	0.944106	0.940467	0.94439	0.945076	0.946571	0.949359	0.95496	0.962629	0.980407	0.998044	0.949953	0.953018	0.945047	0.960944	0.965651	0.975198	0.987757	0.997522	0.999939	1	1
16.5	0.942058	0.943659	0.948112	0.951431	0.959451	0.970209	0.982699	0.996959	0.940647	0.940593	0.94052	0.936664	0.940677	0.941092	0.942275	0.944202	0.94938	0.956073	0.974238	0.995859	0.944403	0.94698	0.940843	0.954137	0.9588	0.968265	0.982116	0.994935	0.999727	1	1
17.5	0.937173	0.938413	0.941737	0.944779	0.952436	0.962617	0.974688	0.992627	0.93705	0.93699	0.936938	0.93286	0.936948	0.937055	0.937865	0.938752	0.943328	0.948673	0.966524	0.99202	0.938609	0.940562	0.936575	0.946709	0.951126	0.960138	0.974656	0.990349	0.998989	0.999997	1
18.5	0.932191	0.932977	0.934931	0.937614	0.944447	0.953514	0.964502	0.985011	0.933453	0.933387	0.933357	0.929064	0.933206	0.932966	0.933342	0.932995	0.936779	0.940366	0.956993	0.985863	0.932624	0.933788	0.932245	0.93866	0.942808	0.950679	0.965063	0.982838	0.996831	0.999964	1
19.5	0.927119	0.927365	0.927687	0.929916	0.935355	0.942587	0.951905	0.972969	0.929856	0.929784	0.929782	0.925275	0.929447	0.928828	0.928693	0.926918	0.929672	0.931077	0.945352	0.976452	0.926412	0.926661	0.927852	0.92999	0.933166	0.939863	0.953018	0.971193	0.991488	0.999664	1
20.5	0.921961	0.921579	0.920044	0.921652	0.925086	0.929471	0.936582	0.955683	0.926259	0.92618	0.926206	0.921486	0.925674	0.92464	0.923931	0.920509	0.922006	0.920719	0.931266	0.962783	0.920018	0.919183	0.923401	0.920702	0.92283	0.927635	0.938229	0.954125	0.979914	0.997786	1
21.5	0.916721	0.915597	0.911955	0.91279	0.913575	0.913775	0.918098	0.932038	0.922662	0.922576	0.922637	0.917706	0.921886	0.920394	0.919032	0.913752	0.913729	0.909187	0.914429	0.943364	0.913413	0.911359	0.91889	0.910798	0.911549	0.913893	0.92044	0.930378	0.957585	0.989502	1
22.5	0.911404	0.909441	0.903472	0.903306	0.900788	0.895241	0.895772	0.900055	0.919065	0.918973	0.919068	0.913933	0.918082	0.916099	0.914011	0.906634	0.904803	0.896413	0.89457	0.916217	0.906636	0.903184	0.914324	0.900286	0.89931	0.898674	0.899445	0.898704	0.919567	0.962734	1
23.5	0.906013	0.903119	0.8946	0.893183	0.886668	0.873645	0.868543	0.856423	0.915468	0.91537	0.915504	0.91016	0.914264	0.911755	0.908852	0.899141	0.895213	0.882298	0.871422	0.87904	0.899664	0.894661	0.909701	0.889173	0.886136	0.881928	0.875103	0.858489	0.861368	0.897616	1
24.5	0.906396	0.906396	0.906396	0.906396	0.906396	0.906396	0.906396	0.906396					0.906396	0.906396	0.906396	0.906396	0.906396	0.906396			0.906396	0.906396	0.906396	0.906396	0.906396	0.906396	0.906396	0.906396	0.906396	0.906396	0.906396

Account 380

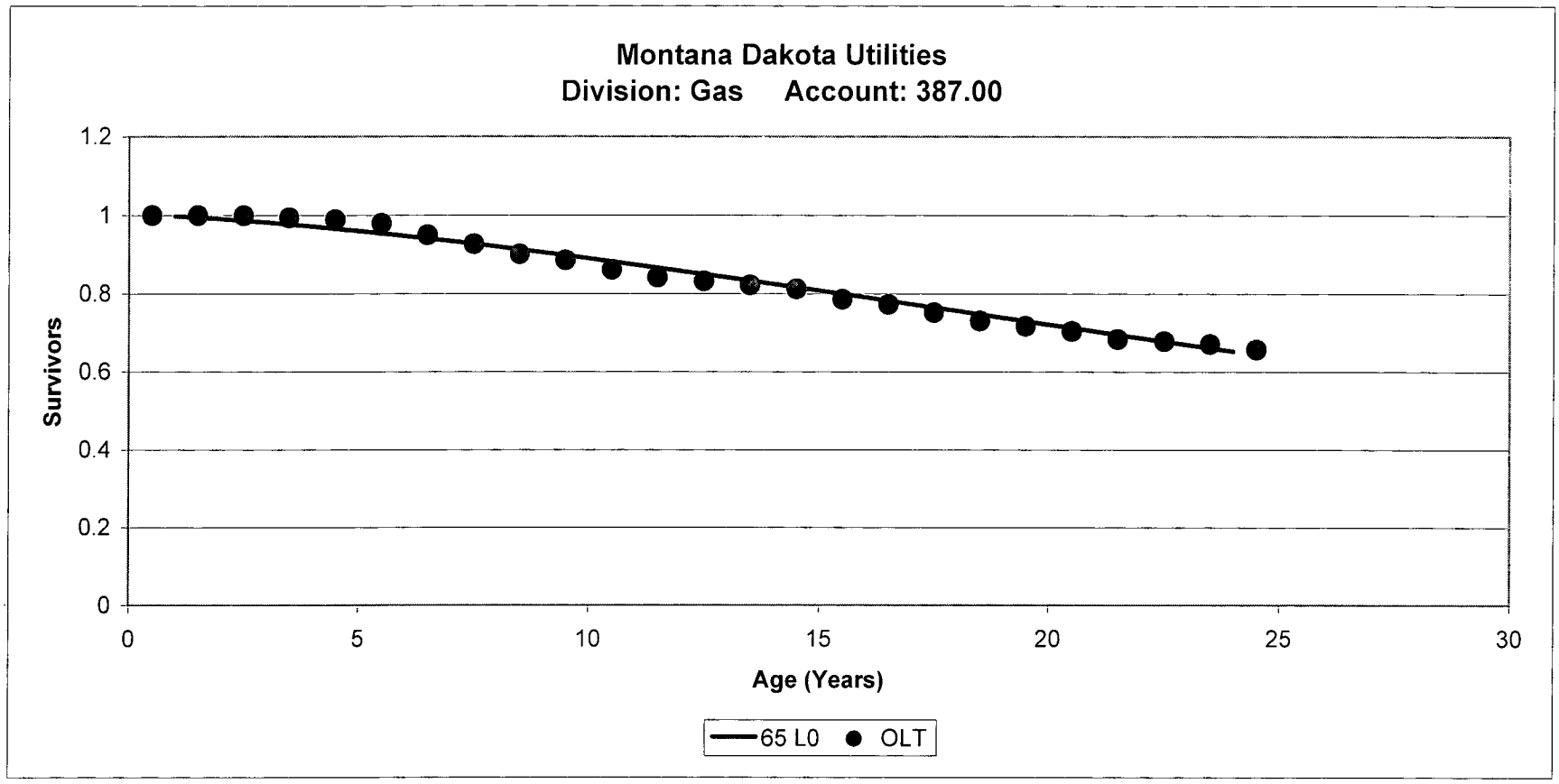
Full Band: 1977-2001

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	1,972,164.31	0.00	0.0000	100.0000	1.0000
1.5	1,891,832.12	-2,021.54	0.1069	99.8931	1.0000
2.5	1,808,926.54	-8,341.09	0.4611	99.5389	0.9989
3.5	1,739,947.29	-10,237.09	0.5884	99.4116	0.9943
4.5	1,655,297.92	-15,906.59	0.9610	99.0390	0.9885
5.5	1,521,366.91	-45,277.71	2.9761	97.0239	0.9790
6.5	1,348,236.79	-32,152.11	2.3848	97.6152	0.9498
7.5	1,288,082.12	-35,929.92	2.7894	97.2106	0.9272
8.5	1,083,213.24	-18,723.66	1.7285	98.2715	0.9013
9.5	988,428.91	-26,985.67	2.7302	97.2698	0.8857
10.5	897,238.02	-20,775.98	2.3155	97.6845	0.8616
11.5	769,447.54	-8,889.06	1.1553	98.8447	0.8416
12.5	716,599.17	-8,428.50	1.1762	98.8238	0.8319
13.5	660,708.94	-8,013.35	1.2128	98.7872	0.8221
14.5	537,238.18	-17,489.38	3.2554	96.7446	0.8121
15.5	475,834.02	-7,780.82	1.6352	98.3648	0.7857
16.5	366,465.51	-10,064.03	2.7462	97.2538	0.7729
17.5	277,756.60	-7,814.60	2.8135	97.1865	0.7516
18.5	209,219.30	-3,717.12	1.7767	98.2233	0.7305
19.5	157,818.85	-3,013.58	1.9095	98.0905	0.7175
20.5	117,204.51	-3,318.67	2.8315	97.1685	0.7038
21.5	101,057.72	-771.03	0.7630	99.2370	0.6839
22.5	74,146.27	-828.38	1.1172	98.8828	0.6787
23.5	54,415.24	-1,165.65	2.1421	97.8579	0.6711
24.5	20,995.33	-1,283.44	6.1130	93.8870	0.6567

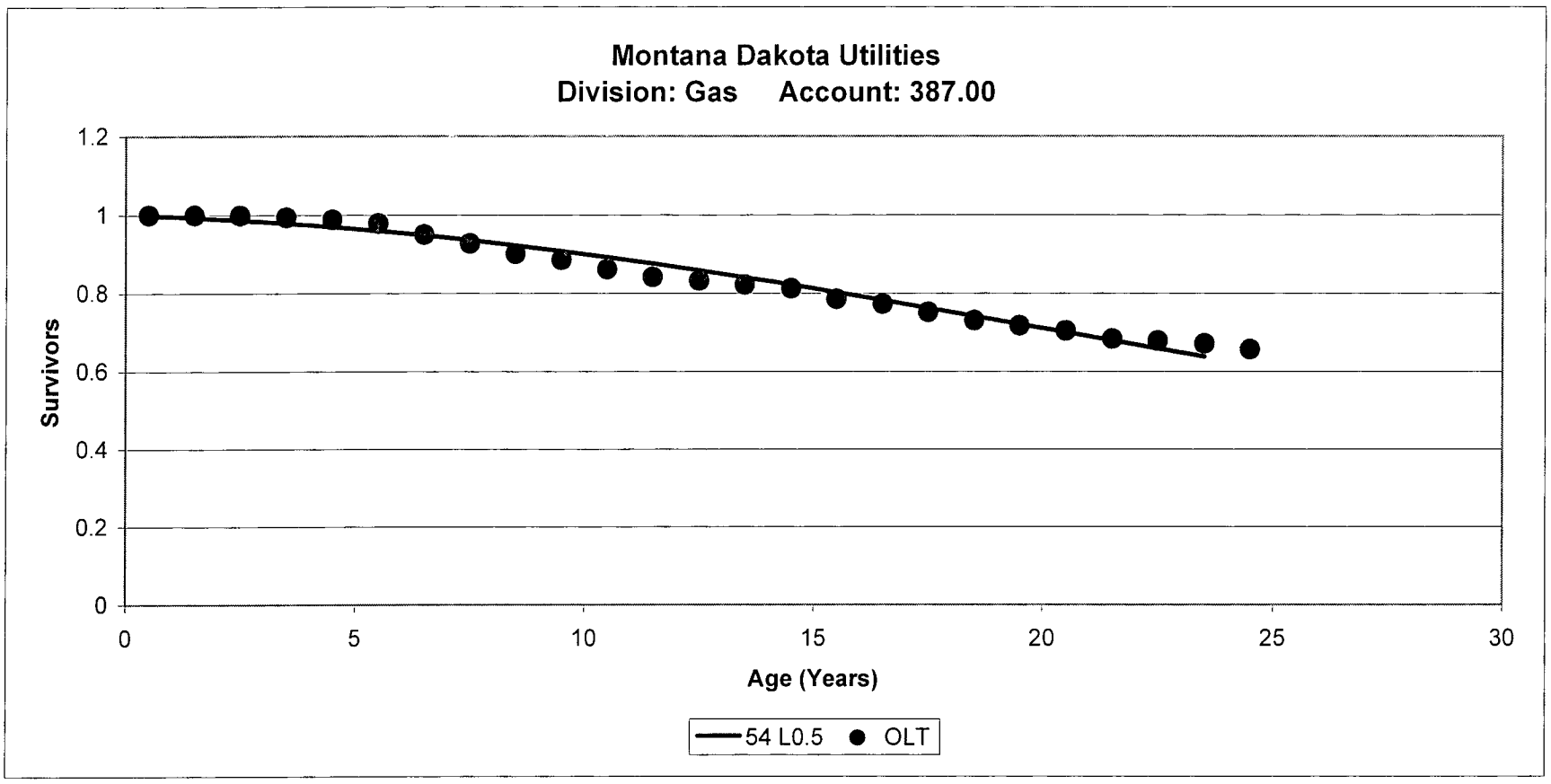
Account: 387

Curve Name	Curve Age	Least Sum of Squares
L0	65	6,467.56
L0.5	54	6,468.31
R1.5	41	6,469.69
S0	46	6,472.43
S-0.5	58	6,475.20
R1	50	6,478.61
R2	36	6,479.86
R0.5	63	6,491.22
S0.5	41	6,492.40
L1	46	6,496.10
O2	87	6,498.45
O1	78	6,498.54
O3	128	6,500.24
O4	178	6,501.05
R2.5	32	6,513.92
L1.5	41	6,526.67
S1	36	6,552.29
S1.5	34	6,604.70
R3	30	6,605.90
L2	36	6,618.26
S2	31	6,715.92
L3	31	6,796.38
R4	27	6,843.77
S3	29	6,924.45
L4	28	6,987.83
S4	27	7,229.09
R5	26	7,284.16
L5	26	7,299.00
S5	26	7,547.64
S6	25	7,803.17
SQ	25	8,403.19

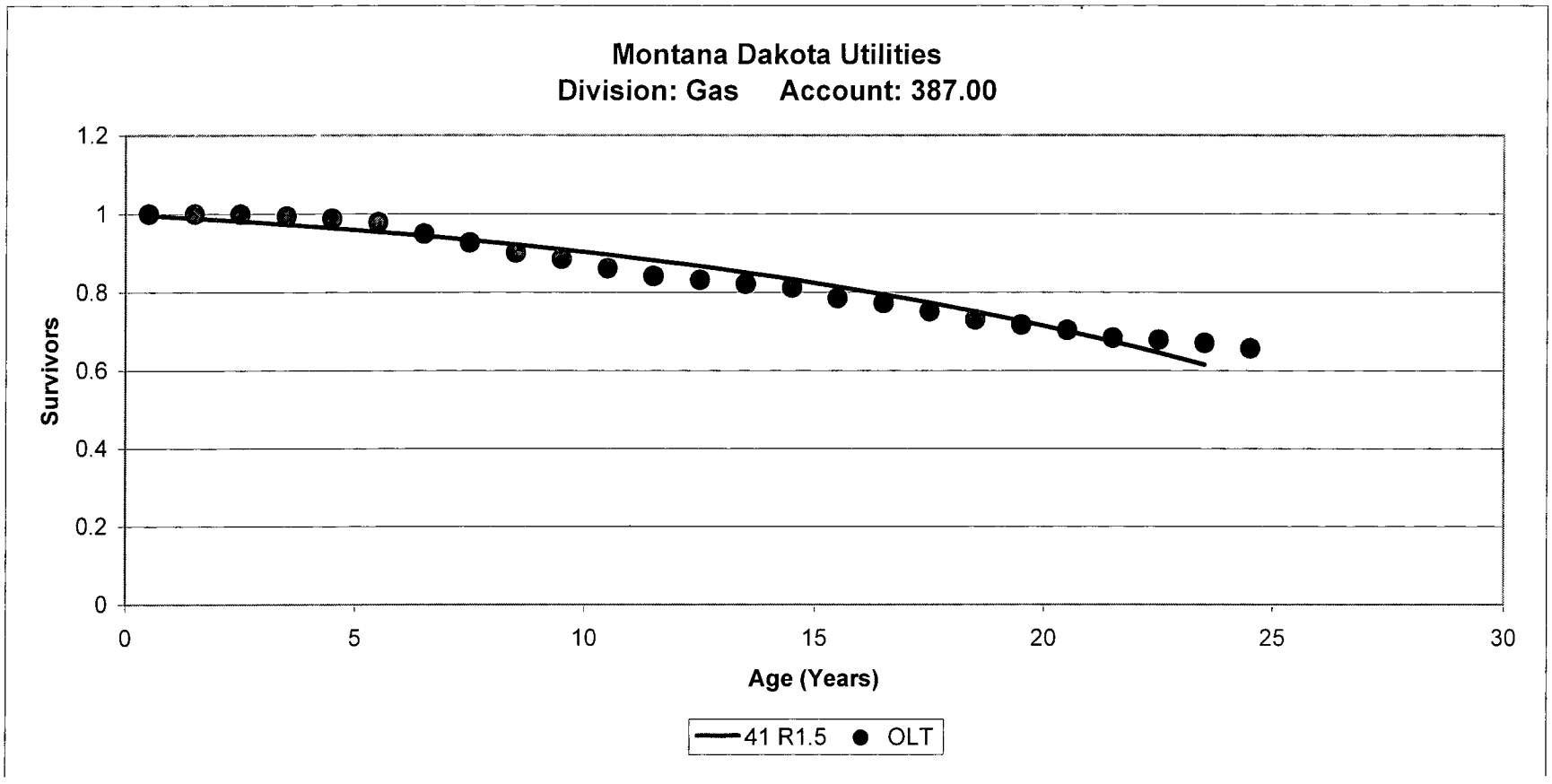
Account: 387
Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

Age	L0	L0.5	L1	L1.5	L2	L3	L4	L5	O1	O2	O3	O4	R0.5	R1	R1.5	R2	R2.5	R3	R4	R5	S0	S0.5	S0.5	S1	S1.5	S2	S3	S4	S5	S6	SQ
0.5	0.998002	0.998424	0.998988	0.999451	0.999992	1	1	1	0.993243	0.993157	0.992973	0.992843	0.993875	0.995363	0.996574	0.99807	0.998823	0.999662	0.99998	1	0.99943	0.999675	0.995849	0.999983	0.999991	1	1	1	1	1	1
1.5	0.991384	0.993522	0.99637	0.997921	0.999799	1	1	1	0.97973	0.979464	0.978942	0.978556	0.981488	0.985744	0.989332	0.993801	0.996148	0.998784	0.999916	1	0.996274	0.99773	0.986706	0.999652	0.999805	0.999995	1	1	1	1	1
2.5	0.982549	0.986978	0.992754	0.995605	0.999116	0.999997	1	1	0.966216	0.965765	0.964943	0.964321	0.968912	0.975666	0.981549	0.988935	0.99298	0.997573	0.999799	1	0.99098	0.994258	0.976666	0.998573	0.999182	0.999944	1	1	1	1	1
3.5	0.972137	0.979098	0.987986	0.992245	0.997679	0.999914	1	1	0.952703	0.95206	0.95098	0.950146	0.956146	0.96512	0.973196	0.983409	0.989237	0.995936	0.999595	1	0.983918	0.989297	0.965868	0.996414	0.997882	0.999743	0.999996	1	1	1	1
4.5	0.960514	0.970006	0.981895	0.987668	0.995252	0.999558	1	1	0.939189	0.938352	0.93706	0.93603	0.943193	0.954121	0.964246	0.977156	0.984826	0.99376	0.999249	1	0.975247	0.982816	0.954391	0.992908	0.995672	0.999217	0.999976	1	1	1	1
5.5	0.947891	0.959763	0.974277	0.981664	0.991679	0.998694	1	1	0.925676	0.924642	0.923181	0.921977	0.930054	0.942661	0.954672	0.970103	0.979642	0.990921	0.998684	1	0.965166	0.974833	0.942299	0.987845	0.992313	0.998117	0.9999	1	1	1	1
6.5	0.934426	0.948407	0.965039	0.974122	0.986831	0.99708	0.999993	1	0.912162	0.910931	0.909348	0.907996	0.916731	0.930756	0.944441	0.962175	0.973566	0.987268	0.99778	1	0.953747	0.96534	0.929644	0.981058	0.987565	0.996138	0.999676	1	1	1	1
7.5	0.920228	0.935964	0.954085	0.964926	0.980589	0.994484	0.9999	1	0.898649	0.897218	0.895571	0.8941	0.903223	0.918407	0.933517	0.953289	0.966467	0.982638	0.996381	1	0.941134	0.954311	0.916468	0.972399	0.981184	0.992931	0.999131	0.999997	1	1	1
8.5	0.90541	0.922461	0.941292	0.954017	0.972903	0.990697	0.999487	1	0.885135	0.883505	0.881847	0.880285	0.889536	0.90562	0.921871	0.943358	0.958211	0.976857	0.994274	0.999999	0.927389	0.94177	0.902806	0.961799	0.972939	0.988121	0.997984	0.999982	1	1	1
9.5	0.890064	0.907928	0.926692	0.941388	0.963676	0.985511	0.99836	1	0.871622	0.869791	0.868181	0.866556	0.875672	0.892399	0.909453	0.93229	0.948649	0.969733	0.991158	0.999982	0.912606	0.927744	0.888692	0.949199	0.96261	0.981324	0.995827	0.999911	1	1	1
10.5	0.874265	0.892404	0.910308	0.92688	0.952436	0.978674	0.99599	1	0.858108	0.856078	0.854582	0.85292	0.86163	0.878712	0.8962	0.919987	0.93762	0.961059	0.986683	0.999883	0.896856	0.912245	0.874153	0.93457	0.950003	0.972171	0.992112	0.999652	1	1	1
11.5	0.858077	0.875943	0.892156	0.910328	0.938507	0.969803	0.991772	0.999982	0.844595	0.842365	0.841052	0.839395	0.847399	0.864536	0.882044	0.906345	0.924956	0.950613	0.980407	0.99951	0.8802	0.895301	0.859218	0.917911	0.934949	0.960316	0.986165	0.998898	0.999999	1	1
12.5	0.84156	0.858604	0.872406	0.891495	0.921393	0.9583	0.985063	0.99975	0.831081	0.828651	0.827594	0.825978	0.832968	0.849818	0.86691	0.891257	0.910466	0.938148	0.971742	0.998452	0.862716	0.876975	0.843908	0.899245	0.91732	0.945468	0.977195	0.996989	0.999985	1	1
13.5	0.824777	0.840467	0.851215	0.870365	0.900788	0.943321	0.975257	0.99865	0.817568	0.814937	0.814215	0.812673	0.818322	0.834523	0.850714	0.874609	0.893954	0.923405	0.960106	0.996036	0.844443	0.857318	0.82825	0.878608	0.897027	0.92738	0.964367	0.992841	0.999894	1	1
14.5	0.807783	0.821625	0.828746	0.84698	0.876558	0.923844	0.961831	0.99548	0.804054	0.801224	0.800923	0.799486	0.803446	0.8186	0.833376	0.856284	0.875224	0.906112	0.944798	0.99127	0.825463	0.83636	0.812266	0.856066	0.874027	0.905885	0.946878	0.984799	0.99945	1	1
15.5	0.790628	0.802177	0.805276	0.821535	0.848948	0.898847	0.944265	0.988641	0.790541	0.78751	0.787718	0.786433	0.788323	0.802003	0.814824	0.836167	0.854054	0.885956	0.92501	0.982796	0.805803	0.814197	0.795979	0.831715	0.848327	0.880889	0.923994	0.970561	0.997722	0.999997	1
16.5	0.773361	0.782246	0.781066	0.79434	0.818307	0.867547	0.921836	0.976442	0.777027	0.773797	0.774605	0.773521	0.772931	0.784699	0.794985	0.81414	0.830204	0.862589	0.900066	0.969031	0.785542	0.790899	0.779409	0.805656	0.819986	0.852382	0.895133	0.947663	0.99246	0.999947	1
17.5	0.756033	0.761946	0.75639	0.765728	0.785078	0.829621	0.893226	0.957372	0.763514	0.760083	0.761598	0.760745	0.757259	0.766635	0.773789	0.790095	0.803423	0.835619	0.869257	0.947724	0.764711	0.766532	0.762576	0.778007	0.789112	0.820441	0.859932	0.913542	0.979198	0.999403	1
18.5	0.738688	0.741398	0.731559	0.736047	0.749841	0.78536	0.856123	0.929759	0.75	0.746369	0.748692	0.748112	0.741292	0.747799	0.751176	0.763932	0.773431	0.804598	0.831959	0.915518	0.743372	0.741187	0.745499	0.748898	0.755865	0.785226	0.818275	0.866059	0.950828	0.9956	1
19.5	0.721354	0.720719	0.706738	0.705554	0.713197	0.735683	0.807566	0.890411	0.736486	0.732656	0.735895	0.735636	0.725018	0.728147	0.727095	0.735572	0.739974	0.769089	0.787881	0.868287	0.721567	0.714959	0.728197	0.718473	0.720452	0.746983	0.770392	0.804465	0.899393	0.978453	1
20.5	0.704041	0.700027	0.681974	0.674553	0.675713	0.682034	0.745385	0.833587	0.722973	0.718942	0.72322	0.723331	0.708421	0.70768	0.701497	0.70496	0.702859	0.728719	0.735775	0.801364	0.699345	0.687936	0.710687	0.686874	0.683124	0.706031	0.716871	0.729228	0.818317	0.92463	1
21.5	0.686765	0.67938	0.657304	0.643315	0.637933	0.626178	0.670081	0.753305	0.709459	0.705228	0.710666	0.711186	0.691494	0.686383	0.674383	0.672082	0.661961	0.683209	0.672571	0.711426	0.676754	0.660212	0.692988	0.654279	0.644173	0.662762	0.658577	0.642566	0.706601	0.804501	1
22.5	0.669538	0.658801	0.632761	0.612103	0.600341	0.569957	0.586089	0.64909	0.695946	0.691515	0.698234	0.699207	0.674233	0.664257	0.645762	0.63697	0.617297	0.6325	0.596397	0.599124	0.653834	0.631897	0.675116	0.620856	0.603922	0.617624	0.596653	0.548393	0.571782	0.612404	1
23.5	0.652372	0.638313	0.608389	0.581144	0.56334	0.515057	0.500581	0.529802	0.682432	0.677801	0.685939	0.687399	0.656636	0.641325	0.615669	0.599719	0.569092	0.576858	0.508688	0.470141	0.630636	0.603094	0.657091	0.586785	0.562723	0.571117	0.532453	0.451551	0.428171	0.387565	1
24.5	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784					0.860784	0.860784	0.860784	0.860784	0.860784	0.860784			0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784

Account 387

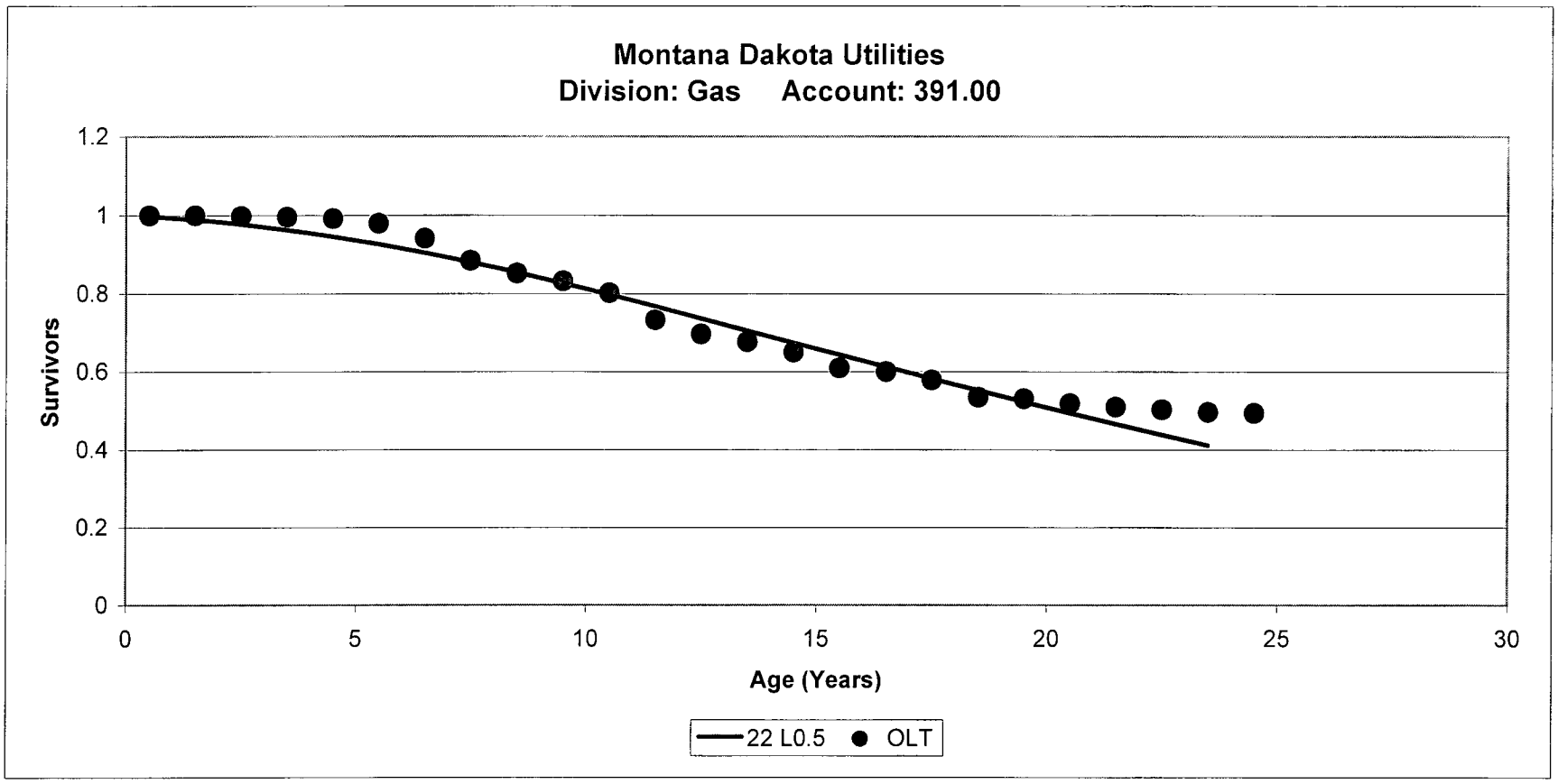
Full Band: 1977-2001

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	2,190,278.82	0.00	0.0000	100.0000	1.0000
1.5	2,151,756.70	-5,620.34	0.2612	99.7388	1.0000
2.5	1,765,702.51	-3,660.03	0.2073	99.7927	0.9974
3.5	1,715,988.60	-6,189.31	0.3607	99.6393	0.9953
4.5	1,656,214.64	-20,361.87	1.2294	98.7706	0.9917
5.5	1,556,615.53	-61,387.84	3.9437	96.0563	0.9795
6.5	1,388,158.55	-83,158.81	5.9906	94.0094	0.9409
7.5	1,205,382.54	-44,519.12	3.6934	96.3066	0.8845
8.5	1,083,792.19	-25,452.24	2.3484	97.6516	0.8519
9.5	1,023,219.01	-37,150.84	3.6308	96.3692	0.8319
10.5	980,431.56	-84,054.69	8.5732	91.4268	0.8017
11.5	808,524.60	-39,882.69	4.9328	95.0672	0.7329
12.5	703,296.87	-20,178.74	2.8692	97.1308	0.6968
13.5	669,801.51	-26,196.10	3.9110	96.0890	0.6768
14.5	622,290.20	-38,704.11	6.2196	93.7804	0.6503
15.5	565,843.08	-8,714.84	1.5402	98.4598	0.6099
16.5	532,337.59	-18,722.41	3.5170	96.4830	0.6005
17.5	481,551.32	-37,151.65	7.7150	92.2850	0.5794
18.5	332,620.09	-2,047.42	0.6155	99.3845	0.5347
19.5	191,258.71	-4,608.74	2.4097	97.5903	0.5314
20.5	133,204.85	-2,159.23	1.6210	98.3790	0.5186
21.5	112,372.57	-1,577.87	1.4041	98.5959	0.5102
22.5	79,610.98	-965.03	1.2122	98.7878	0.5030
23.5	38,005.55	-211.92	0.5576	99.4424	0.4969
24.5	23,030.02	0.00	0.0000	100.0000	0.4941

Account: 391

Curve Name	Curve Age	Least Sum of Squares
L0.5	22	2,682.01
L0	24	2,684.72
S-0.5	21	2,757.52
L1	22	2,801.06
S0	21	2,838.72
R0.5	21	2,870.02
O2	25	2,936.30
O1	22	2,939.24
R1	20	2,985.72
O3	34	3,039.99
O4	46	3,105.00
S0.5	20	3,136.64
L1.5	21	3,234.39
R1.5	20	3,368.03
S1	20	3,625.93
L2	21	3,930.08
R2	20	4,002.67
S1.5	20	4,342.39
R2.5	20	4,931.46
S2	20	5,244.90
L3	20	5,987.90
R3	20	6,093.74
S3	20	7,424.05
R4	20	8,846.66
L4	20	8,936.46
S4	20	10,789.78
L5	20	12,364.27
R5	21	12,987.80
S5	21	14,363.30
S6	22	18,004.56
SQ	25	26,280.15

Account: 391
Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
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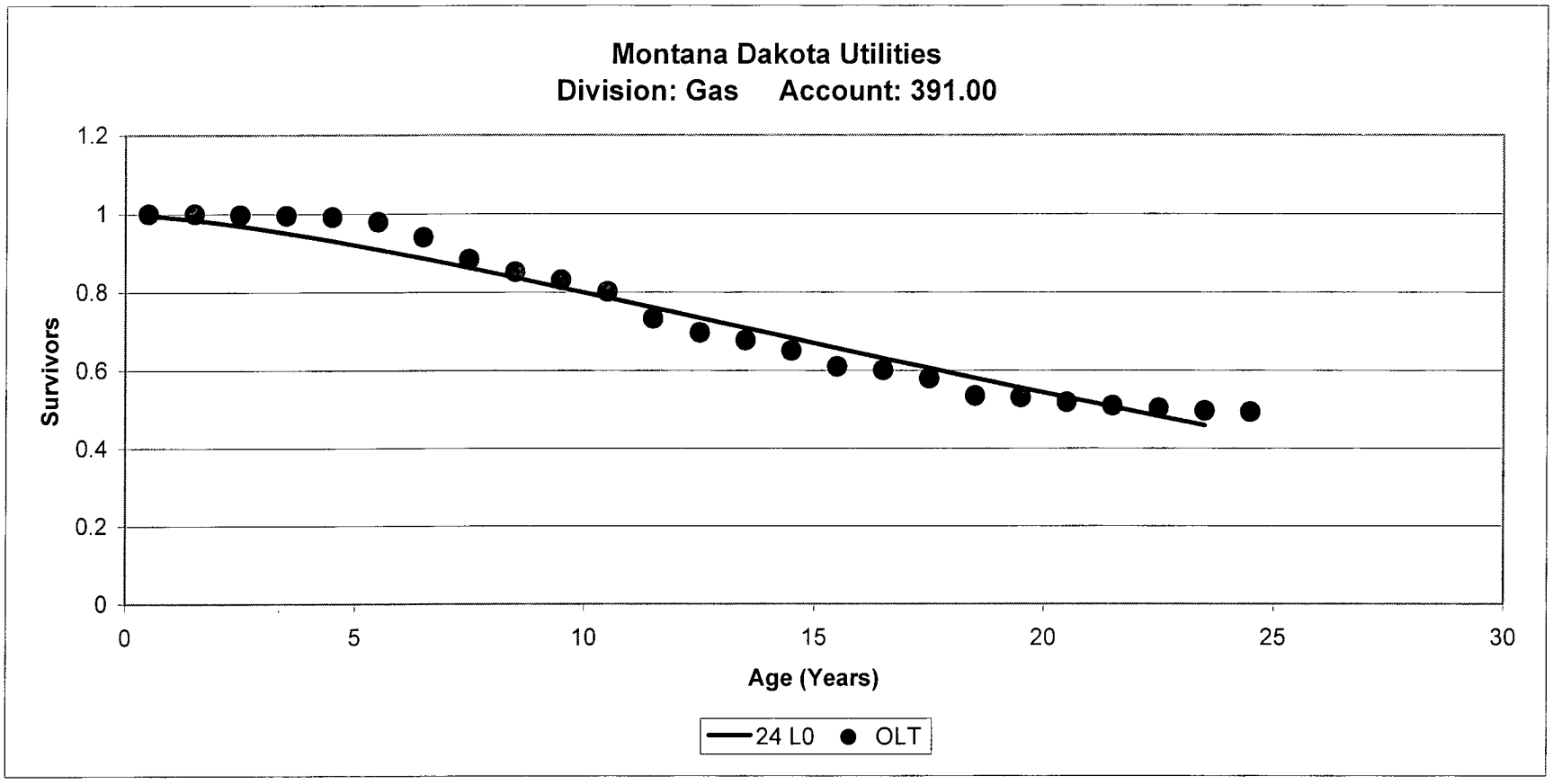
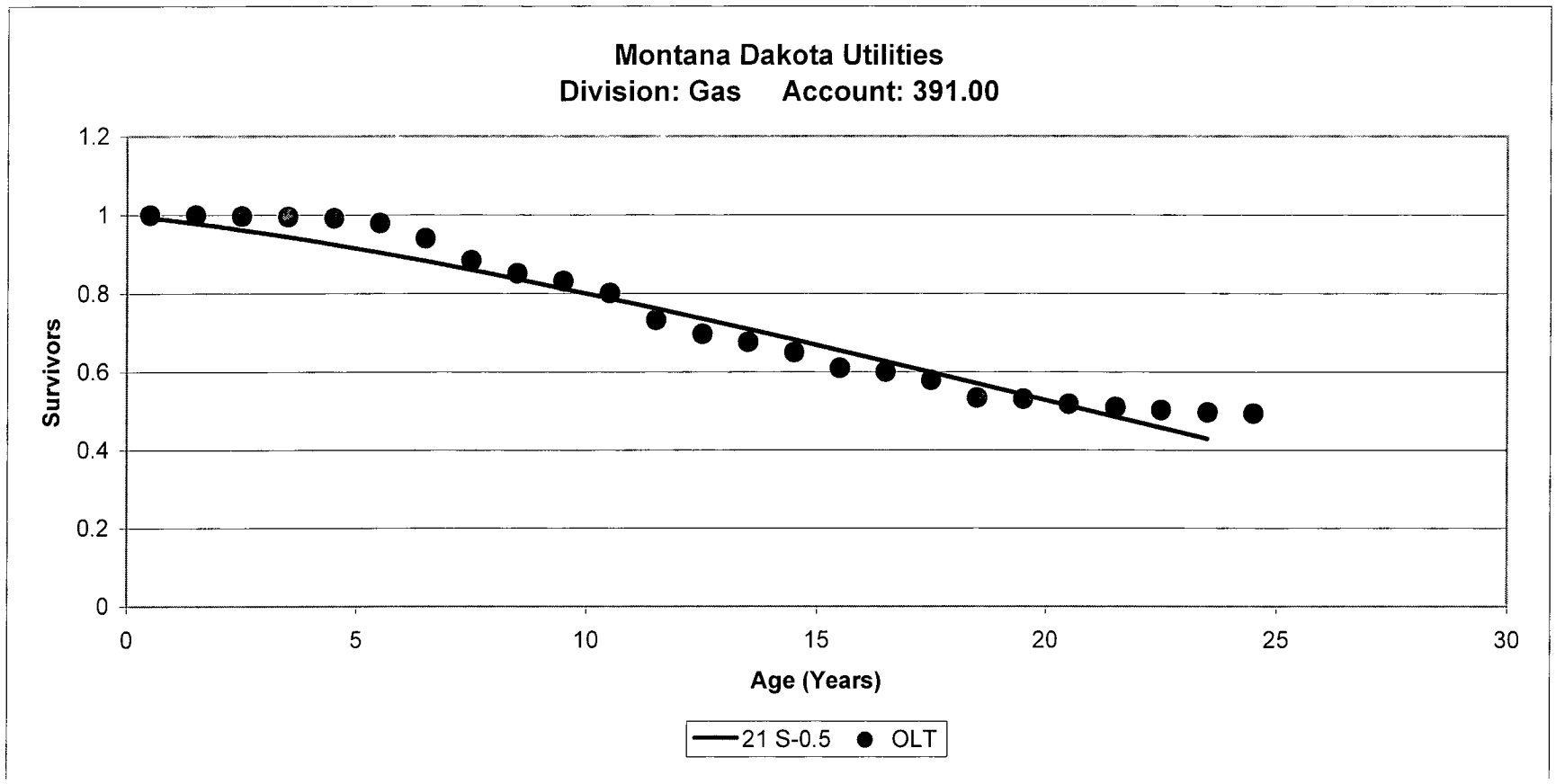
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

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U-399-02-183
Exhibit____(CWK-3)

Age	L0	L0.5	L1	L1.5	L2	L3	L4	L5	O1	O2	O3	O4	R0.5	R1	R1.5	R2	R2.5	R3	R4	R5	S0	S0.5	S-0.5	S1	S1.5	S2	S3	S4	S5	S6	SQ
0.5	0.99665	0.997393	0.998575	0.99924	0.999982	1	1	1	0.988536	0.988776	0.987811	0.9874	0.990943	0.993475	0.995519	0.997563	0.998574	0.999586	0.999977	1	0.999014	0.999445	0.993555	0.999964	0.999982	1	1	1	1	1	1
1.5	0.984909	0.988754	0.99453	0.996878	0.999585	1	1	1	0.965909	0.968313	0.963504	0.962316	0.972524	0.979751	0.985898	0.992045	0.995252	0.99846	0.999895	1	0.993489	0.998092	0.978887	0.99928	0.999632	0.999985	1	1	1	1	1
2.5	0.969334	0.976936	0.988472	0.992892	0.998179	0.999964	1	1	0.943182	0.943836	0.939309	0.937408	0.953894	0.96512	0.975339	0.985557	0.991186	0.996814	0.999736	1	0.984281	0.989989	0.962384	0.99707	0.998457	0.999844	0.999999	1	1	1	1
3.5	0.95113	0.962437	0.979971	0.986763	0.995252	0.999622	1	1	0.920455	0.921351	0.915242	0.912703	0.934454	0.94959	0.963782	0.977974	0.986225	0.994476	0.999436	1	0.972037	0.981151	0.944352	0.992692	0.995998	0.999304	0.999986	1	1	1	1
4.5	0.930934	0.945395	0.968592	0.97809	0.990428	0.998532	1	1	0.897727	0.898883	0.891326	0.888232	0.914811	0.933172	0.951163	0.969155	0.980195	0.991235	0.998897	1	0.957134	0.969554	0.924995	0.985663	0.99179	0.997917	0.999912	1	1	1	1
5.5	0.909172	0.925945	0.954085	0.966578	0.983437	0.996225	0.99999	1	0.875	0.876374	0.86758	0.864024	0.894772	0.915883	0.937417	0.958952	0.972899	0.986847	0.997968	1	0.939871	0.955186	0.904459	0.975637	0.985362	0.995089	0.999639	1	1	1	1
6.5	0.886158	0.904134	0.936192	0.952045	0.974101	0.99226	0.999825	1	0.852273	0.853884	0.844029	0.840126	0.874344	0.89774	0.922471	0.947202	0.964117	0.981032	0.996423	1	0.920482	0.93806	0.882859	0.962374	0.976248	0.990122	0.998866	0.999996	1	1	1
7.5	0.862154	0.880146	0.914951	0.934376	0.962205	0.986231	0.999043	1	0.829545	0.831393	0.820696	0.816565	0.853521	0.878712	0.906221	0.93373	0.953603	0.973476	0.993941	1	0.899161	0.918221	0.860294	0.945733	0.964005	0.982277	0.997063	0.999978	1	1	1
8.5	0.837386	0.854136	0.890425	0.913226	0.946819	0.97767	0.996864	1	0.806818	0.808903	0.797609	0.793375	0.832275	0.858713	0.88853	0.918347	0.941091	0.963836	0.99008	0.999989	0.876109	0.895742	0.836864	0.925656	0.948239	0.970823	0.993425	0.999868	1	1	1
9.5	0.812048	0.826393	0.862941	0.888138	0.926636	0.965816	0.992284	0.999987	0.784091	0.786413	0.774797	0.770592	0.81056	0.837629	0.86924	0.900851	0.926293	0.951735	0.98426	0.9999	0.851492	0.870726	0.812651	0.902161	0.928626	0.955091	0.986868	0.999418	1	1	1
10.5	0.786319	0.797231	0.832913	0.85896	0.900788	0.949376	0.984216	0.999691	0.761364	0.763923	0.752285	0.748249	0.788323	0.815334	0.848181	0.881029	0.908899	0.93677	0.975744	0.99951	0.825463	0.843303	0.787731	0.875335	0.904932	0.934529	0.975081	0.997995	0.999999	1	1
11.5	0.760368	0.767046	0.800922	0.82591	0.869008	0.926518	0.971628	0.997981	0.738636	0.741432	0.730103	0.726382	0.765504	0.791706	0.825181	0.858657	0.888576	0.918495	0.96364	0.998296	0.798154	0.813628	0.762172	0.845324	0.877029	0.908735	0.95964	0.994288	0.999982	1	1
12.5	0.734353	0.736235	0.767643	0.78965	0.831775	0.895241	0.953602	0.992627	0.715909	0.718942	0.708279	0.705041	0.742059	0.766635	0.80007	0.833506	0.864959	0.896413	0.946917	0.995341	0.769717	0.781878	0.736049	0.812325	0.844907	0.87749	0.936151	0.986061	0.999852	1	1
13.5	0.708367	0.705197	0.733817	0.751005	0.789957	0.854048	0.929131	0.980751	0.693182	0.696452	0.68684	0.684237	0.717943	0.740032	0.772691	0.80535	0.837652	0.869955	0.924451	0.989279	0.740284	0.748248	0.709428	0.776583	0.808678	0.840774	0.904438	0.970103	0.999149	1	1
14.5	0.682453	0.674228	0.699977	0.710683	0.744689	0.802609	0.896384	0.959591	0.670455	0.673962	0.665814	0.663996	0.693123	0.711838	0.742909	0.77398	0.806226	0.838471	0.895105	0.978311	0.709979	0.712956	0.68237	0.738385	0.768581	0.798777	0.863712	0.942546	0.996343	0.999999	1
15.5	0.656657	0.643426	0.666262	0.669356	0.697202	0.742111	0.851775	0.926372	0.647727	0.651472	0.645226	0.644341	0.66757	0.682021	0.710621	0.739222	0.770228	0.801235	0.857844	0.959996	0.67892	0.67623	0.654936	0.69805	0.724974	0.751897	0.81373	0.899596	0.987512	0.999976	1
16.5	0.631021	0.612862	0.632761	0.627691	0.648727	0.675119	0.790373	0.87549	0.625	0.628984	0.625101	0.625289	0.641282	0.650591	0.675773	0.700957	0.729227	0.757499	0.811891	0.930881	0.647232	0.638314	0.627187	0.655929	0.678325	0.700723	0.754888	0.838562	0.965321	0.999664	1
17.5	0.60559	0.582615	0.599575	0.58628	0.600341	0.605045	0.70919	0.796608	0.602273	0.6065	0.605459	0.606857	0.614266	0.617593	0.638375	0.659156	0.682886	0.706617	0.756398	0.885985	0.615034	0.599462	0.599184	0.612393	0.629204	0.646015	0.688255	0.758896	0.919567	0.996967	1
18.5	0.580405	0.55275	0.566785	0.545616	0.55293	0.535413	0.611785	0.682502	0.579545	0.584023	0.586319	0.58907	0.586547	0.583116	0.598515	0.613914	0.631079	0.648245	0.687895	0.819321	0.582439	0.559934	0.570982	0.567833	0.578255	0.588677	0.615532	0.662872	0.840512	0.982938	1
19.5	0.555507	0.523342	0.534487	0.506096	0.507189	0.469209	0.509029	0.541986	0.556818	0.56156	0.567698	0.571912	0.558159	0.54729	0.556386	0.565484	0.574046	0.582609	0.602523	0.725779	0.549562	0.519999	0.542639	0.522655	0.526186	0.529716	0.53893	0.555608	0.724311	0.933399	1
20.5	0.530936	0.494451	0.502758	0.468002	0.463586	0.408475	0.412149	0.399823	0.534091	0.53912	0.549608	0.555384	0.529163	0.510287	0.512299	0.514311	0.51254	0.510769	0.501755	0.60488	0.516516	0.479928	0.51421	0.47727	0.473739	0.470208	0.460998	0.444337	0.578515	0.815346	1
21.5	0.50673	0.466147	0.471686	0.431516	0.422403	0.354205	0.328228	0.280347	0.511364	0.516719	0.532059	0.539483	0.499638	0.472324	0.46669	0.461057	0.447921	0.434785	0.393403	0.463753	0.463414	0.439994	0.485755	0.432092	0.42167	0.411248	0.384397	0.337073	0.421458	0.617318	1
22.5	0.482924	0.438485	0.441342	0.396744	0.383767	0.306496	0.259664	0.192942	0.488636	0.494378	0.515057	0.5242	0.469676	0.433654	0.420129	0.406605	0.382137	0.357669	0.288318	0.317766	0.450368	0.400466	0.457328	0.387533	0.370721	0.353909	0.311674	0.241052	0.275644	0.382651	1
23.5	0.459555	0.411522	0.4118	0.363738	0.347702	0.264839	0.204971	0.132802	0.465912	0.472127	0.498605	0.509538	0.439384	0.394572	0.373302	0.352033	0.317539	0.283044	0.196076	0.187738	0.417491	0.361613	0.428986	0.343997	0.3216	0.299204	0.245046	0.161389	0.159447	0.184627	1
24.5	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784					0.860784	0.860784	0.860784	0.860784	0.860784	0.860784			0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784	0.860784

Account 391

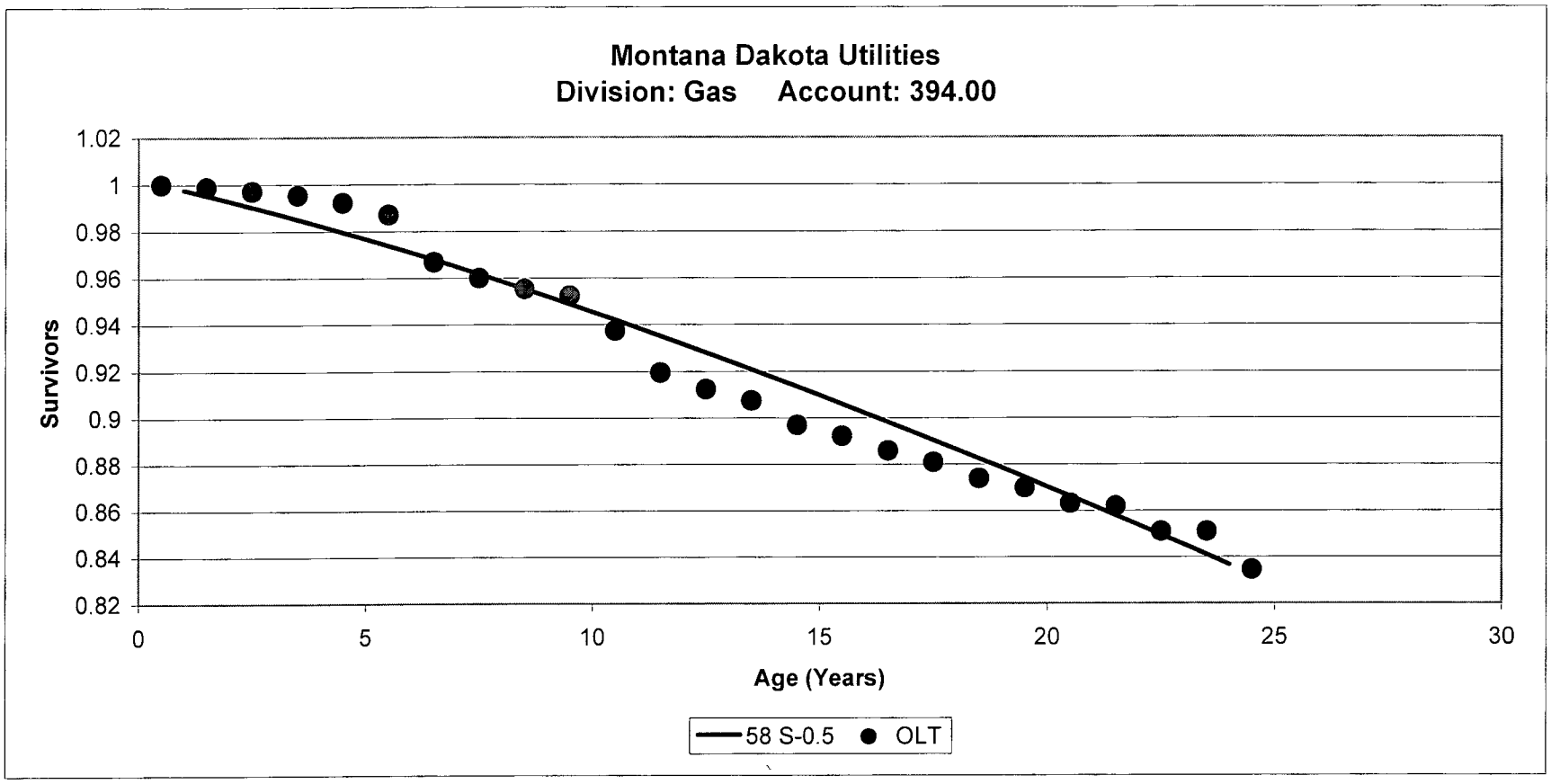
Full Band: 1977-2001

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	3,751,673.34	-4,051.57	0.1080	99.8920	1.0000
1.5	3,617,249.81	-6,192.07	0.1712	99.8288	0.9989
2.5	3,473,162.95	-6,084.87	0.1752	99.8248	0.9972
3.5	3,377,794.18	-10,884.14	0.3222	99.6778	0.9955
4.5	3,274,321.83	-17,051.55	0.5208	99.4792	0.9923
5.5	3,143,919.34	-64,280.15	2.0446	97.9554	0.9871
6.5	2,887,358.18	-20,657.05	0.7154	99.2846	0.9669
7.5	2,848,806.69	-13,578.26	0.4766	99.5234	0.9600
8.5	2,488,764.58	-7,756.72	0.3117	99.6883	0.9554
9.5	2,403,380.50	-37,698.49	1.5686	98.4314	0.9524
10.5	2,278,385.74	-43,893.04	1.9265	98.0735	0.9375
11.5	2,010,151.66	-15,467.25	0.7695	99.2305	0.9194
12.5	1,934,695.72	-10,542.89	0.5449	99.4551	0.9124
13.5	1,849,233.18	-21,288.28	1.1512	98.8488	0.9074
14.5	1,772,519.57	-9,317.62	0.5257	99.4743	0.8969
15.5	1,711,966.83	-12,334.00	0.7205	99.2795	0.8922
16.5	1,579,743.24	-8,615.58	0.5454	99.4546	0.8858
17.5	1,329,174.95	-10,496.75	0.7897	99.2103	0.8810
18.5	1,019,534.12	-4,776.81	0.4685	99.5315	0.8740
19.5	680,105.70	-5,316.22	0.7817	99.2183	0.8699
20.5	442,981.38	-592.25	0.1337	99.8663	0.8631
21.5	336,567.78	-4,256.04	1.2645	98.7355	0.8620
22.5	243,189.17	0.00	0.0000	100.0000	0.8511
23.5	128,048.93	-2,484.37	1.9402	98.0598	0.8511
24.5	64,142.70	-2,444.12	3.8104	96.1896	0.8346

Account: 394

Curve Name	Curve Age	Least Sum of Squares
S-0.5	58	6,846.68
R1	50	6,848.03
R0.5	62	6,848.13
L0	65	6,849.46
O2	87	6,849.80
O1	77	6,849.85
O3	127	6,850.27
O4	176	6,850.48
R1.5	42	6,859.03
L0.5	54	6,869.68
S0	46	6,881.32
R2	36	6,903.03
S0.5	41	6,924.57
L1	46	6,934.69
R2.5	33	6,970.88
L1.5	41	6,984.54
S1	37	7,020.93
S1.5	34	7,097.69
R3	30	7,101.79
L2	37	7,118.06
S2	32	7,244.49
L3	32	7,350.95
R4	28	7,413.29
S3	29	7,502.34
L4	28	7,573.35
S4	27	7,838.61
R5	26	7,880.22
L5	27	7,922.50
S5	26	8,134.99
S6	25	8,374.96
SQ	25	8,781.38

Account: 394
Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
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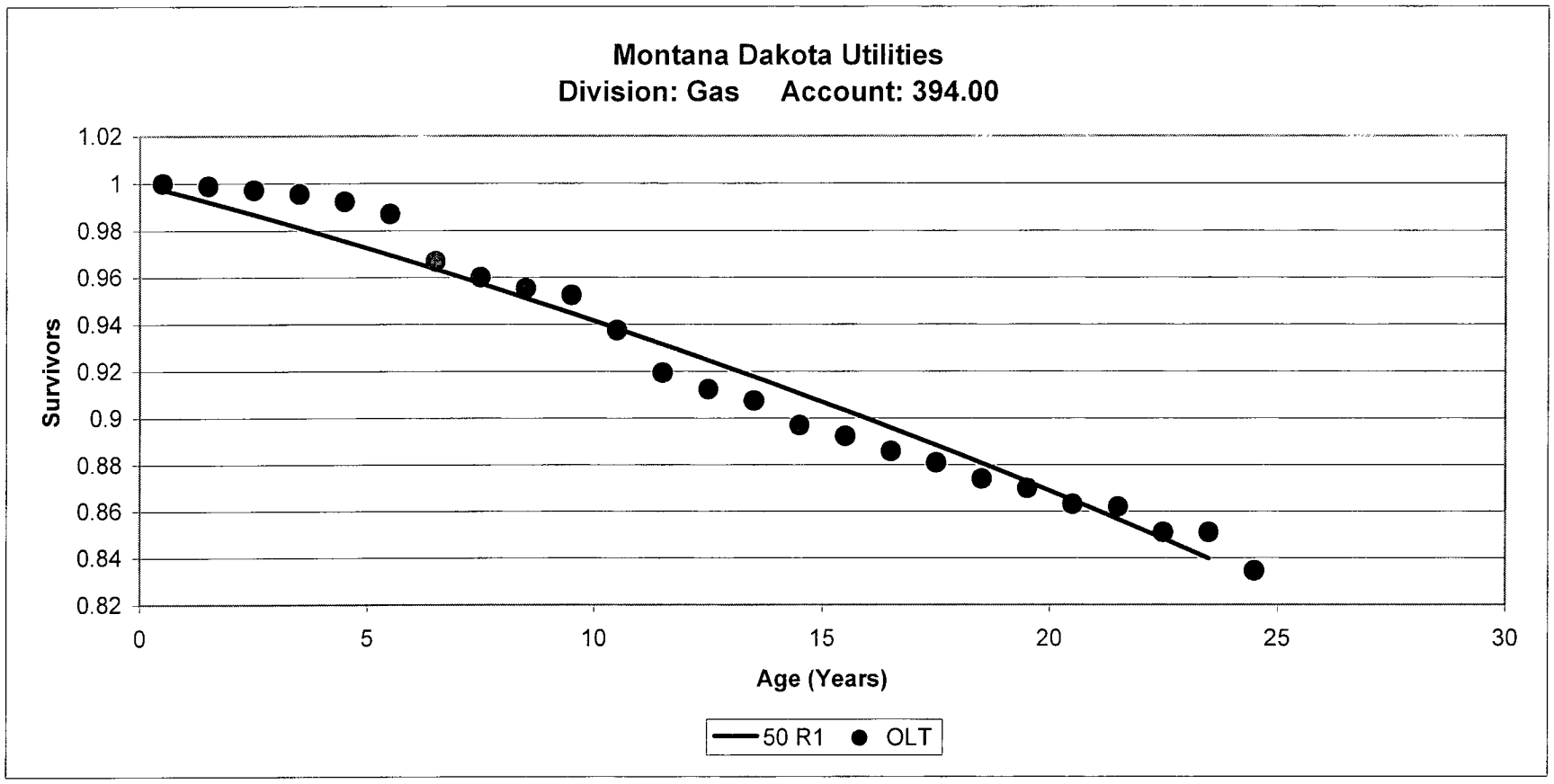

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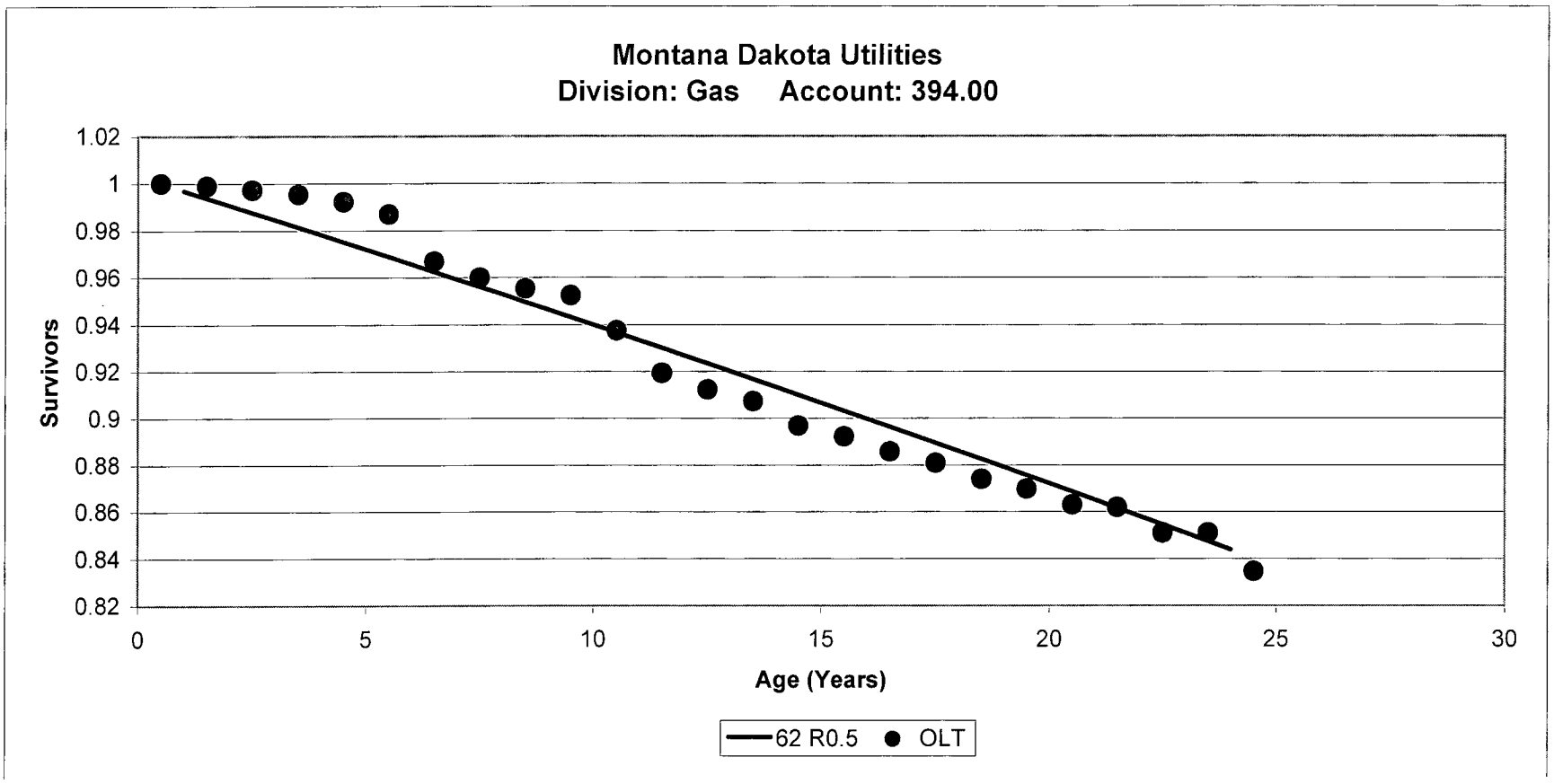

Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 10
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Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

Age	L0	L0 5	L1	L1 5	L2	L3	L4	L5	O1	O2	O3	O4	R0 5	R1	R1 5	R2	R2 5	R3	R4	R5	S0	S0 5	S-0 5	S1	S1 5	S2	S3	S4	S5	S6	SQ
0 5	0 99903	0 999147	0 999364	0 999637	0 999996	1	1	1	0 996753	0 996775	0 996735	0 996706	0 996943	0 997419	0 997892	0 99867	0 999152	0 999733	0 999984	1	0 999748	0 999838	0 997755	0 999992	0 999995	1	1	1	1	1	1
1 5	0 99613	0 996626	0 997843	0 998733	0 999921	1	1	1	0 99026	0 990324	0 990208	0 990118	0 990796	0 992148	0 993533	0 995825	0 997296	0 99908	0 999937	1	0 998318	0 998922	0 992967	0 999871	0 999916	0 999998	1	1	1	1	1
2 5	0 992281	0 993361	0 995948	0 997517	0 999646	1	1	1	0 983766	0 983872	0 983688	0 983544	0 984604	0 986731	0 988976	0 992707	0 995196	0 998226	0 99986	1	0 995932	0 997324	0 987861	0 999462	0 999652	0 999982	1	1	1	1	1
3 5	0 987716	0 989505	0 99363	0 995898	0 999058	0 99999	1	1	0 977273	0 977418	0 977176	0 976974	0 978361	0 981169	0 984205	0 989289	0 992823	0 997132	0 999736	1	0 992728	0 995051	0 982485	0 998636	0 999108	0 999915	0 999999	1	1	1	1
4 5	0 982621	0 985129	0 990837	0 993826	0 998062	0 999911	1	1	0 970779	0 970962	0 97067	0 970423	0 972073	0 975461	0 979222	0 985557	0 990143	0 995748	0 999541	1	0 988789	0 99215	0 976845	0 997286	0 998189	0 999737	0 999994	1	1	1	1
5 5	0 977019	0 980273	0 987522	0 991196	0 996567	0 999661	1	1	0 964286	0 964505	0 964172	0 963978	0 965738	0 969609	0 97402	0 981489	0 987121	0 994005	0 999242	1	0 984176	0 988577	0 970977	0 995308	0 996802	0 999358	0 999974	1	1	1	1
6 5	0 971041	0 974964	0 983618	0 987984	0 994494	0 999132	1	1	0 957792	0 958046	0 957682	0 957348	0 959355	0 963612	0 968584	0 977062	0 983719	0 991848	0 998793	1	0 978919	0 984371	0 964901	0 992615	0 994855	0 998664	0 999914	1	1	1	1
7 5	0 964659	0 969204	0 979092	0 984107	0 991794	0 998206	0 999995	1	0 951299	0 951587	0 9512	0 950829	0 952926	0 957471	0 962919	0 972243	0 979893	0 989207	0 998133	1	0 973067	0 979499	0 958619	0 989152	0 992251	0 997516	0 999765	1	1	1	1
8 5	0 95798	0 963014	0 973908	0 979535	0 988418	0 996771	0 999936	1	0 944805	0 945128	0 944728	0 944321	0 946449	0 951187	0 957008	0 967013	0 9756	0 985986	0 997179	1	0 966662	0 973975	0 952138	0 984861	0 988895	0 99576	0 999439	0 999999	1	1	1
9 5	0 950982	0 956409	0 96803	0 974225	0 984301	0 994719	0 999695	1	0 938312	0 938667	0 938264	0 937831	0 939925	0 944761	0 950849	0 961347	0 970791	0 982114	0 995831	0 999999	0 959733	0 967794	0 945479	0 979661	0 984683	0 993224	0 998805	0 999991	1	1	1
10 5	0 943731	0 949393	0 96143	0 968136	0 979439	0 991952	0 999043	1	0 931818	0 932206	0 931809	0 931347	0 933357	0 938194	0 944441	0 955219	0 965414	0 977502	0 993941	0 999989	0 952305	0 960944	0 938648	0 973547	0 979527	0 98973	0 99767	0 999982	1	1	1
11 5	0 936223	0 941974	0 954085	0 961276	0 973814	0 986371	0 997693	1	0 925325	0 925745	0 925363	0 924888	0 926739	0 931486	0 937758	0 948596	0 959415	0 972025	0 991361	0 999933	0 944403	0 953452	0 931644	0 966488	0 973336	0 985096	0 995779	0 999864	1	1	1
12 5	0 928496	0 934155	0 945949	0 953584	0 967371	0 983865	0 99526	0 999996	0 918831	0 919284	0 918928	0 918434	0 920078	0 92464	0 930811	0 941439	0 952734	0 965604	0 987866	0 999728	0 936033	0 945282	0 924478	0 958432	0 966022	0 979133	0 992822	0 999583	1	1	1
13 5	0 920561	0 925945	0 937041	0 945112	0 95998	0 978298	0 991376	0 999921	0 912338	0 912822	0 912504	0 912004	0 91337	0 917655	0 923583	0 93373	0 945313	0 95813	0 983232	0 999161	0 927233	0 936482	0 917162	0 949382	0 957508	0 971665	0 988394	0 999898	0 999996	1	1
14 5	0 912433	0 917333	0 927362	0 935778	0 95141	0 971478	0 98563	0 999477	0 905844	0 90636	0 906091	0 905585	0 906616	0 910534	0 916057	0 925434	0 937087	0 949453	0 977164	0 997856	0 918022	0 927018	0 909701	0 939341	0 94772	0 962541	0 982116	0 997382	0 999971	1	1
15 5	0 904135	0 908343	0 916921	0 925557	0 941388	0 963132	0 977639	0 998038	0 899351	0 899897	0 899688	0 899184	0 89982	0 903277	0 908232	0 916519	0 927991	0 939483	0 969331	0 99526	0 908418	0 916929	0 902088	0 928291	0 936596	0 951618	0 973442	0 99439	0 999846	1	1
16 5	0 895669	0 898988	0 905731	0 914352	0 929677	0 952887	0 987091	0 994658	0 892857	0 893435	0 893296	0 892802	0 892974	0 895882	0 900077	0 906935	0 917954	0 928094	0 9594	0 99062	0 898439	0 906209	0 894341	0 916226	0 924087	0 938773	0 961994	0 988988	0 999357	0 999999	1
17 5	0 887063	0 88927	0 893813	0 902109	0 91617	0 940292	0 953602	0 988134	0 886364	0 886973	0 886919	0 886431	0 886087	0 888345	0 891586	0 896656	0 906901	0 915095	0 946917	0 983006	0 888099	0 894872	0 886464	0 903182	0 910151	0 923909	0 947225	0 979879	0 99778	0 999983	1
18 5	0 878313	0 879212	0 881186	0 888806	0 900788	0 924847	0 936888	0 977275	0 87987	0 88051	0 880553	0 880089	0 879156	0 880661	0 882744	0 885847	0 894759	0 900383	0 931547	0 971278	0 877406	0 88294	0 878458	0 889173	0 894764	0 906954	0 928792	0 965561	0 993521	0 999806	1
19 5	0 869449	0 868821	0 867913	0 874396	0 883446	0 906065	0 916275	0 96107	0 873377	0 874047	0 8742	0 873755	0 872178	0 872824	0 873516	0 873872	0 881448	0 883792	0 912784	0 953945	0 866389	0 870405	0 870326	0 874182	0 877912	0 887865	0 906306	0 944471	0 983643	0 998507	1
20 5	0 860461	0 858114	0 854042	0 85896	0 864275	0 883516	0 890865	0 938422	0 866883	0 867585	0 867859	0 867451	0 865159	0 864826	0 863906	0 861286	0 866882	0 865078	0 890301	0 928817	0 855058	0 857318	0 862077	0 858273	0 859598	0 866619	0 879534	0 915038	0 96349	0 991983	1
21 5	0 851379	0 847101	0 839629	0 842467	0 843385	0 856947	0 859087	0 907387	0 86039	0 861122	0 861533	0 86116	0 858089	0 856661	0 853881	0 847838	0 850973	0 8441	0 863699	0 893174	0 843431	0 843651	0 853716	0 841474	0 839838	0 843236	0 848377	0 875907	0 927503	0 968574	1
22 5	0 842199	0 835814	0 824736	0 825066	0 82089	0 826341	0 819046	0 864612	0 853896	0 854659	0 855224	0 854893	0 850975	0 84832	0 843422	0 833506	0 833628	0 82065	0 832687	0 843807	0 83152	0 829466	0 84524	0 823798	0 818665	0 817783	0 81279	0 826564	0 870346	0 906927	1
23 5	0 832941	0 824274	0 809425	0 806802	0 797002	0 791896	0 76927	0 805523	0 847403	0 848196	0 848928	0 848649	0 843812	0 839796	0 832526	0 818251	0 814746	0 79442	0 797126	0 777788	0 819335	0 814752	0 836659	0 805293	0 796125	0 790344	0 773038	0 767089	0 788991	0 785414	1
24 5	0 860784	0 860784	0 860784	0 860784	0 860784	0 860784	0 860784	0 860784					0 860784	0 860784	0 860784	0 860784	0 860784	0 860784			0 860784	0 860784	0 860784	0 860784	0 860784	0 860784	0 860784	0 860784	0 860784	0 860784	0 860784

Account 394

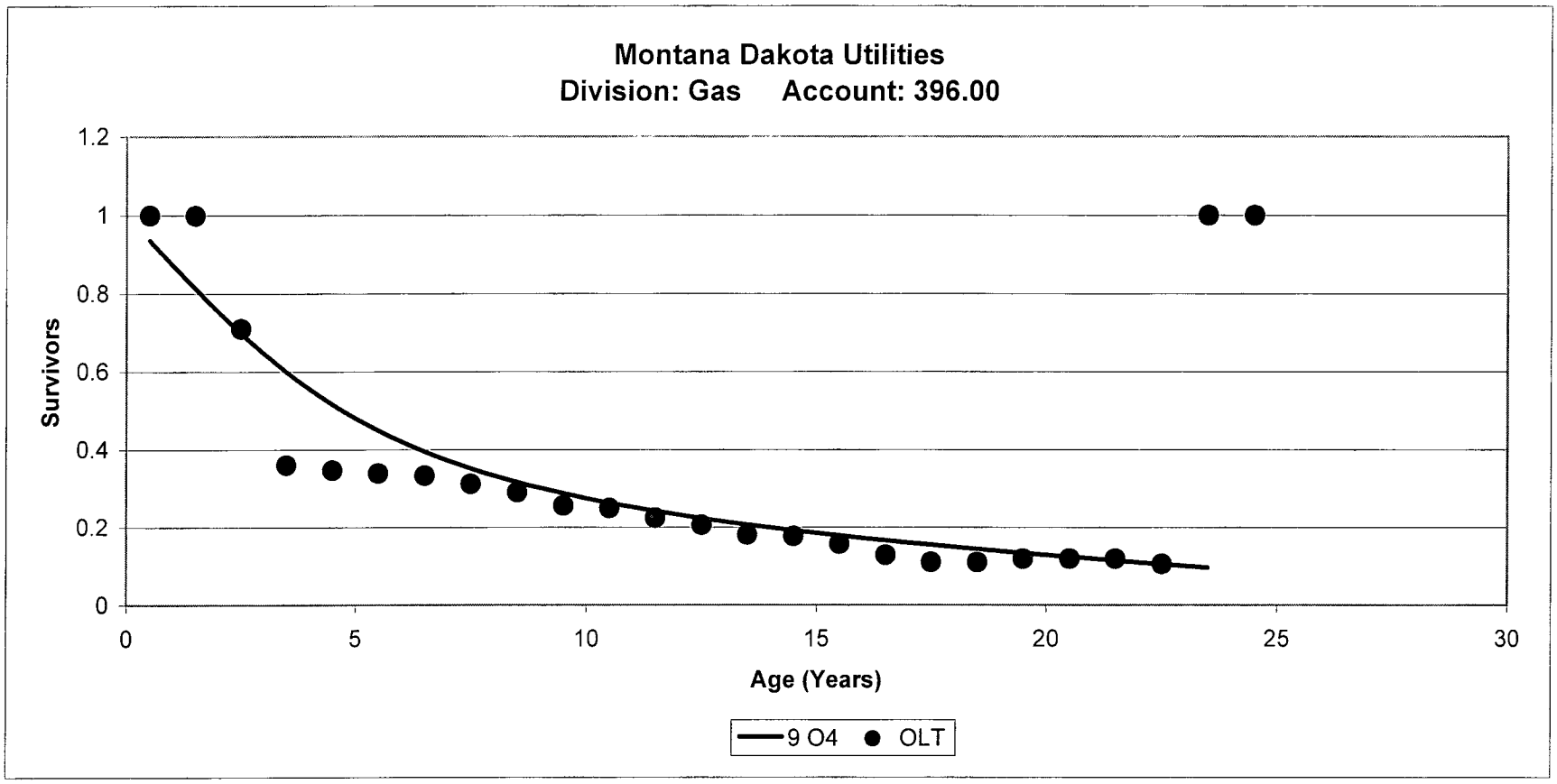
Full Band: 1977-2001

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	14,583,204.67	-12,261.64	0.0841	99.9159	1.0000
1.5	13,055,975.45	-3,774,961.36	28.9137	71.0863	0.9992
2.5	8,738,867.50	-4,305,632.18	49.2699	50.7301	0.7103
3.5	4,126,315.57	-149,520.59	3.6236	96.3764	0.3603
4.5	3,681,206.34	-88,803.50	2.4123	97.5877	0.3473
5.5	3,531,380.70	-57,038.44	1.6152	98.3848	0.3389
6.5	3,274,882.75	-212,539.22	6.4900	93.5100	0.3334
7.5	3,057,709.00	-204,575.94	6.6905	93.3095	0.3118
8.5	2,341,884.56	-279,155.94	11.9201	88.0799	0.2909
9.5	2,015,724.27	-54,222.41	2.6900	97.3100	0.2562
10.5	1,808,466.13	-180,921.60	10.0041	89.9959	0.2493
11.5	1,584,294.69	-130,836.62	8.2584	91.7416	0.2244
12.5	1,400,301.44	-166,824.06	11.9134	88.0866	0.2059
13.5	1,065,710.30	-24,198.63	2.2707	97.7293	0.1813
14.5	998,026.86	-110,272.55	11.0491	88.9509	0.1772
15.5	822,928.94	-151,226.20	18.3766	81.6234	0.1576
16.5	708,801.39	-100,583.15	14.1906	85.8094	0.1287
17.5	611,170.51	0.00	0.0000	100.0000	0.1104
18.5	487,551.03	37,881.85	-7.7698	107.7698	0.1104
19.5	279,913.89	0.00	0.0000	100.0000	0.1190
20.5	206,990.68	0.00	0.0000	100.0000	0.1190
21.5	112,875.63	-12,067.13	10.6906	89.3094	0.1190
22.5	-20.55	-4,918.55	-23934.5499	24034.5499	0.1063
23.5	-3,918.60	0.00	0.0000	100.0000	1.0000
24.5	0.00	0.00	0.0000	100.0000	1.0000

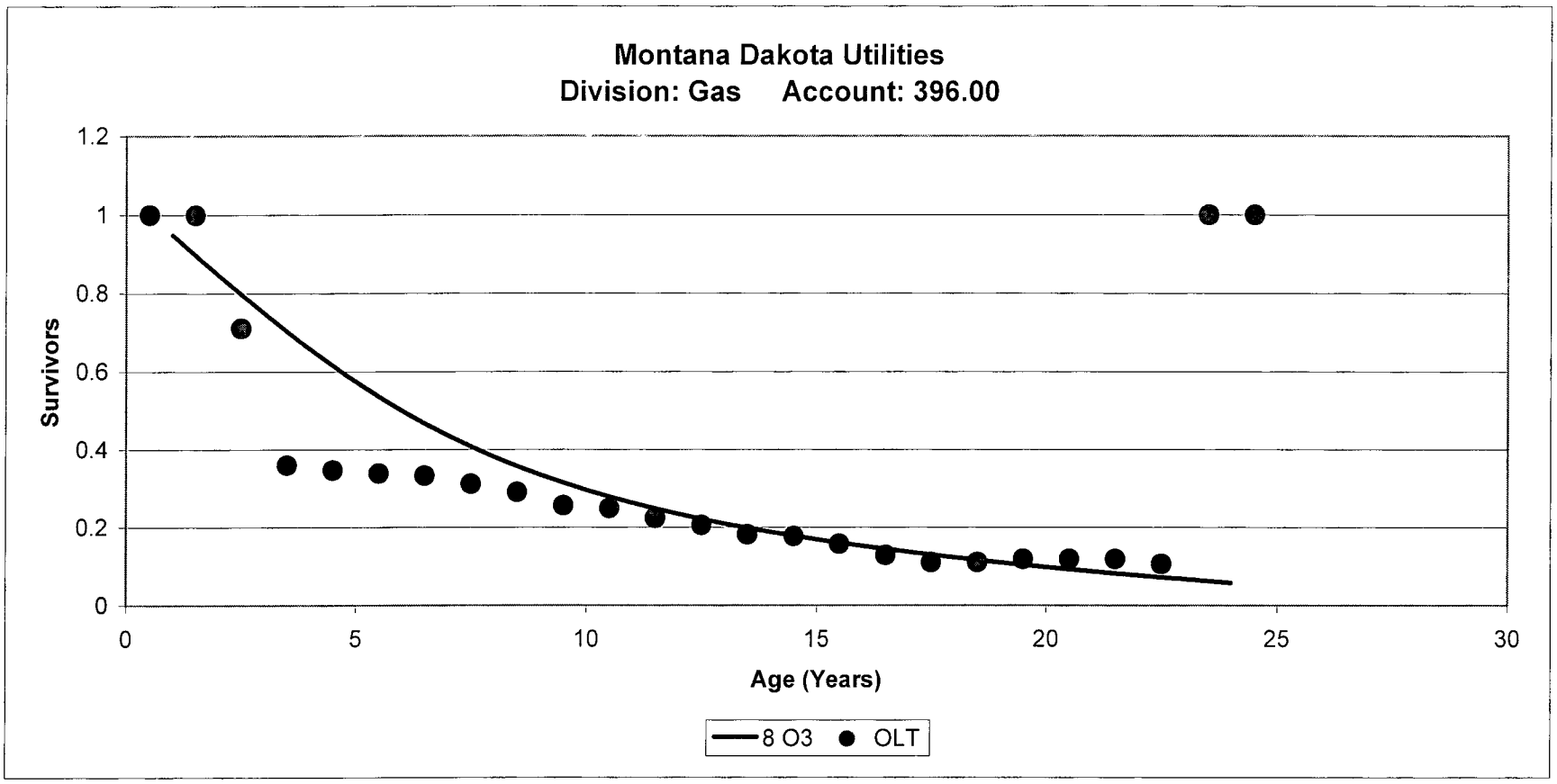
Account: 396

Curve Name	Curve Age	Least Sum of Squares
O4	9	19,656.21
O3	8	21,043.68
O2	6	23,761.90
L0	6	24,339.29
L0.5	6	25,001.85
L1	5	25,561.46
O1	6	25,601.18
S-0.5	5	26,064.33
L1.5	5	26,140.94
R0.5	5	26,329.07
S0	5	26,599.59
L2	5	26,821.88
S0.5	5	27,127.45
R1	5	27,174.04
S1	4	27,637.09
R1.5	4	27,806.27
L3	4	27,925.86
S1.5	4	27,997.94
R2	4	28,277.43
S2	4	28,425.99
R2.5	4	28,719.94
R3	4	29,255.93
S3	4	29,309.91
L4	3	29,393.05
R4	3	29,643.79
S4	3	29,805.69
L5	3	30,011.66
R5	3	30,355.80
S5	3	30,550.14
S6	3	31,297.94
SQ	3	31,466.26

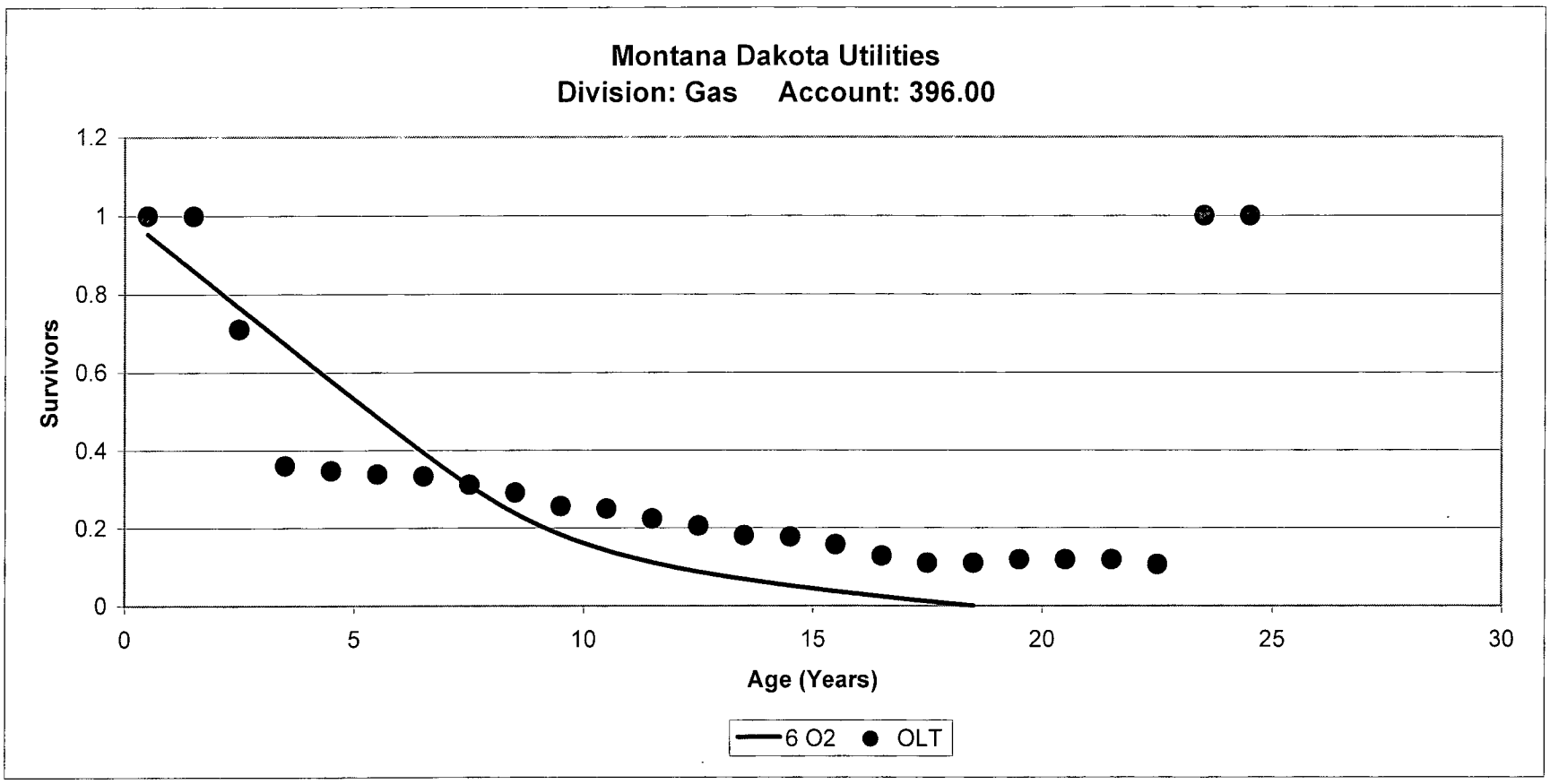
Account: 396
Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 1
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 1
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 1
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)



Analytical Parameters
OLT Observation Band: 1977 - 2001
OLT Retirement Band: 1977 - 2001
Minimum Life Expectancy: 1
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 25 (24.5)

Age	L0	L0 5	L1	L1 5	L2	L3	L4	L5	O1	O2	O3	O4	R0 5	R1	R1 5	R2	R2 5	R3	R4	R5	S0	S0 5	S-0 5	S1	S1 5	S2	S3	S4	S5	S6	SQ
0 5	0 977504	0 985129	0 990539	0 99472	0 998901	0 999964	1	1	0 958333	0 953202	0 948368	0 93603	0 961277	0 972553	0 975339	0 985557	0 991186	0 996814	0 999499	1	0 988369	0 993394	0 969184	0 99707	0 998457 0 964004	0 999844	0 999998 5	1	1	1	1
1 5	0 897806	0 925945	0 934238	0 955201	0 976165	0 986231	0 988773	0 999921	0 875	0 859506	0 846963	0 812673	0 878461	0 906922	0 906221	0 93373	0 953603	0 973476	0 980407	0 99951	0 924522	0 94698	0 887261	0 945733	5	0 982277	0 997063	0 998898 0 826563	0 999999	1 0 986775	1
2 5	0 799222	0 835814	0 817131	0 85896	0 900788	0 895241	0 778233	0 864612	0 791667	0 765797	0 749495	0 699207	0 788323	0 826647	0 80007	0 833506	0 864959	0 896413	0 803355	0 885985	0 825463	0 857318	0 787731	0 812325	0 844906 5	0 877489 5	66666666 0 936151	6	0 919567	33333333 3	1
3 5	0 695398	0 725894	0 669624	0 702477	0 73533	0 605045	0 213245	0 141322	0 708333	0 672088	0 65804	0 599866	0 688072	0 726144	0 638375	0 659156	0 682886	0 706617	0 210253	9 23E-02	0 703824	0 730803	0 676912	0 612393	0 629203 5	0 646015	0 688254 5	0 173386 3	8 039666 E-02	1 320733 E-02	
4 5	0 592963	0 612862	0 524901	0 52965	0 534399	0 306496	0 029319	0 005027	0 625	0 578405	0 574618	0 516788	0 57527	0 600539	0 420129	0 406605	0 382137	0 357669	0 000012		0 569317	0 579768	0 559659	0 387533	0 370720 5	0 353909	0 311674	0 001081			
5 5	0 494775	0 50402	0 391632	0 376725	0 361817	0 142569	5 90E-04		0 541667	0 485094	0 500635	0 449407	0 451533	0 453062	0 199036	0 15696	0 112695	0 068429			0 430613	0 420159	0 440309	0 187619	0 155037 0 017688	0 122455	0 0638				
6 5	0 403257	0 402701	0 275856	0 25412	0 232384	0 052161			0 458337	0 393874	0 436533	0 395389	0 323649	0 297287	0 054628	0 023751	0 012117	0 000482			0 296109	0 26913	0 32306	0 054229	0 035958 0 001532	5 0 000147	0 002913				
7 5	0 320376	0 31164	0 181472	0 159957	0 138442	0 011171			0 37501	0 309388	0 381844	0 351957	0 202776	0 155533	0 004587						0 174488	0 142634	0 212253	0 002918	5	5					
8 5	0 247555	0 232808	0 109854	0 091599	0 073344	0 000695			0 291682	0 238139	0 335527	0 316621	0 101587	0 053148							0 075448	0 05299	0 112737								
9 5	0 185534	0 167207	0 059914	0 046408	0 032901				0 208355	0 18321	0 296327	0 287398	0 028062	0 00609							0 01162	0 006595	0 030827								
10 5	0 134437	0 114933	0 028524	0 020075	0 011626				0 125028	0 142442	0 262998	0 262795																		
11 5	9 38E-02	0 075245	0 011269	7 04E-03	2 81E-03				4 17E-02	0 1118	0 23445	0 241693																		
12 5	0 062809	4 67E-02	0 003377	0 00185	0 000323					8 79E-02	0 209766	0 223279																		
13 5	0 040083	0 027302	0 000636	0 000319	0 000002					0 068339	0 188203	0 206948																		
14 5	2 42E-02	0 015019	0 00004	0 00002						5 18E-02	0 169171	0 192252																		
15 5	1 37E-02	7 77E-03								3 72E-02	0 152195	0 178853																		
16 5	0 007216	0 003793								0 023972	0 136903	0 16649																		
17 5	3 45E-03	1 74E-03								0 011787	0 123002	0 154961																		
18 5	0 001467	7 33E-04								3 72E-04	0 11025	0 144115																		
19 5	0 000529	0 000264									0 098458	0 133834																		
20 5	1 47E-04	7 33E-05									0 08747	0 124014																		
21 5	2 27E-05	1 13E-05									0 077163	0 114584																		
22 5											0 06743	0 10548																		
23 5											0 058189	0 096654																		
24 5																														

Account 396

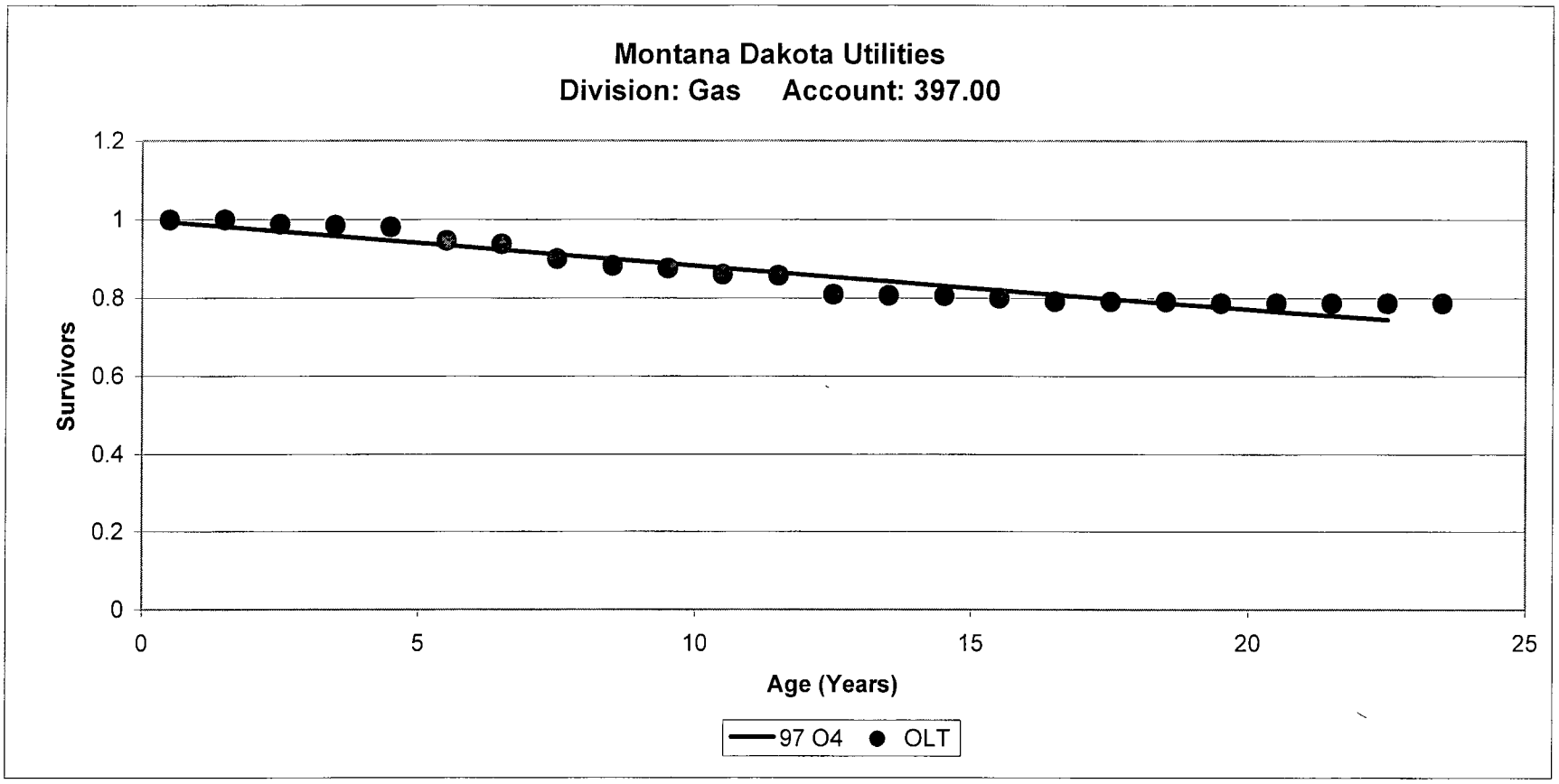
Full Band: 1978-2001

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors (%)
0.5	929,657.39	-143.17	0.0154	99.9846	1.0000
1.5	901,805.62	-10,041.05	1.1134	98.8866	0.9998
2.5	884,071.18	-2,681.47	0.3033	99.6967	0.9887
3.5	874,994.31	-4,041.76	0.4619	99.5381	0.9857
4.5	860,356.28	-30,496.33	3.5446	96.4554	0.9812
5.5	776,057.49	-7,032.17	0.9061	99.0939	0.9464
6.5	722,489.63	-29,160.83	4.0362	95.9638	0.9378
7.5	602,554.48	-11,808.69	1.9598	98.0402	0.9000
8.5	570,026.03	-4,174.60	0.7324	99.2676	0.8823
9.5	522,201.30	-9,187.77	1.7594	98.2406	0.8759
10.5	470,803.10	-1,554.15	0.3301	99.6699	0.8604
11.5	469,137.45	-26,393.70	5.6260	94.3740	0.8576
12.5	405,268.76	-1,383.59	0.3414	99.6586	0.8094
13.5	379,736.20	-481.67	0.1268	99.8732	0.8066
14.5	287,495.62	-1,864.20	0.6484	99.3516	0.8056
15.5	242,825.09	-2,845.27	1.1717	98.8283	0.8003
16.5	253,427.90	0.00	0.0000	100.0000	0.7910
17.5	241,005.49	0.00	0.0000	100.0000	0.7910
18.5	209,263.00	-1,130.45	0.5402	99.4598	0.7910
19.5	151,910.96	0.00	0.0000	100.0000	0.7867
20.5	56,231.43	0.00	0.0000	100.0000	0.7867
21.5	28,641.00	0.00	0.0000	100.0000	0.7867
22.5	21,255.96	0.00	0.0000	100.0000	0.7867
23.5	1,730.82	0.00	0.0000	100.0000	0.7867

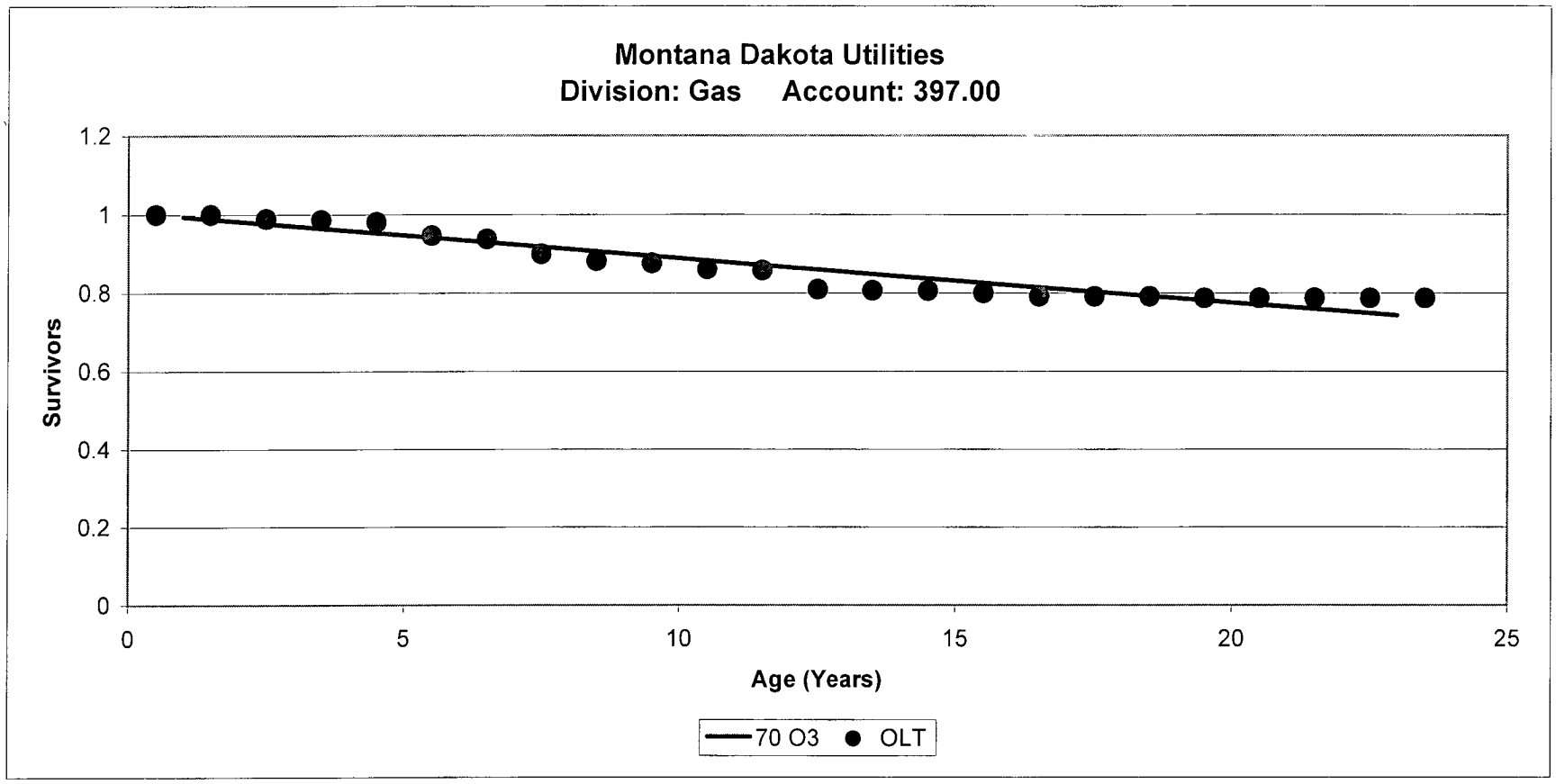
Account: 397

Curve Name	Curve Age	Least Sum of Squares
O4	97	6,193.26
O3	70	6,196.95
O2	49	6,205.36
O1	44	6,205.80
R0.5	37	6,235.70
S-0.5	37	6,287.91
L0	42	6,309.61
R1	32	6,316.79
L0.5	37	6,446.10
R1.5	29	6,463.52
S0	32	6,491.40
S0.5	30	6,689.90
L1	34	6,694.87
R2	27	6,727.82
L1.5	31	6,927.88
S1	28	7,004.88
R2.5	26	7,024.57
S1.5	27	7,283.72
L2	29	7,361.17
R3	25	7,458.95
S2	26	7,693.85
L3	27	8,090.36
R4	24	8,296.84
S3	25	8,424.63
L4	25	8,743.82
S4	24	9,310.36
R5	24	9,543.92
L5	24	9,560.40
S5	24	10,061.05
S6	23	10,661.51
SQ	24	11,541.94

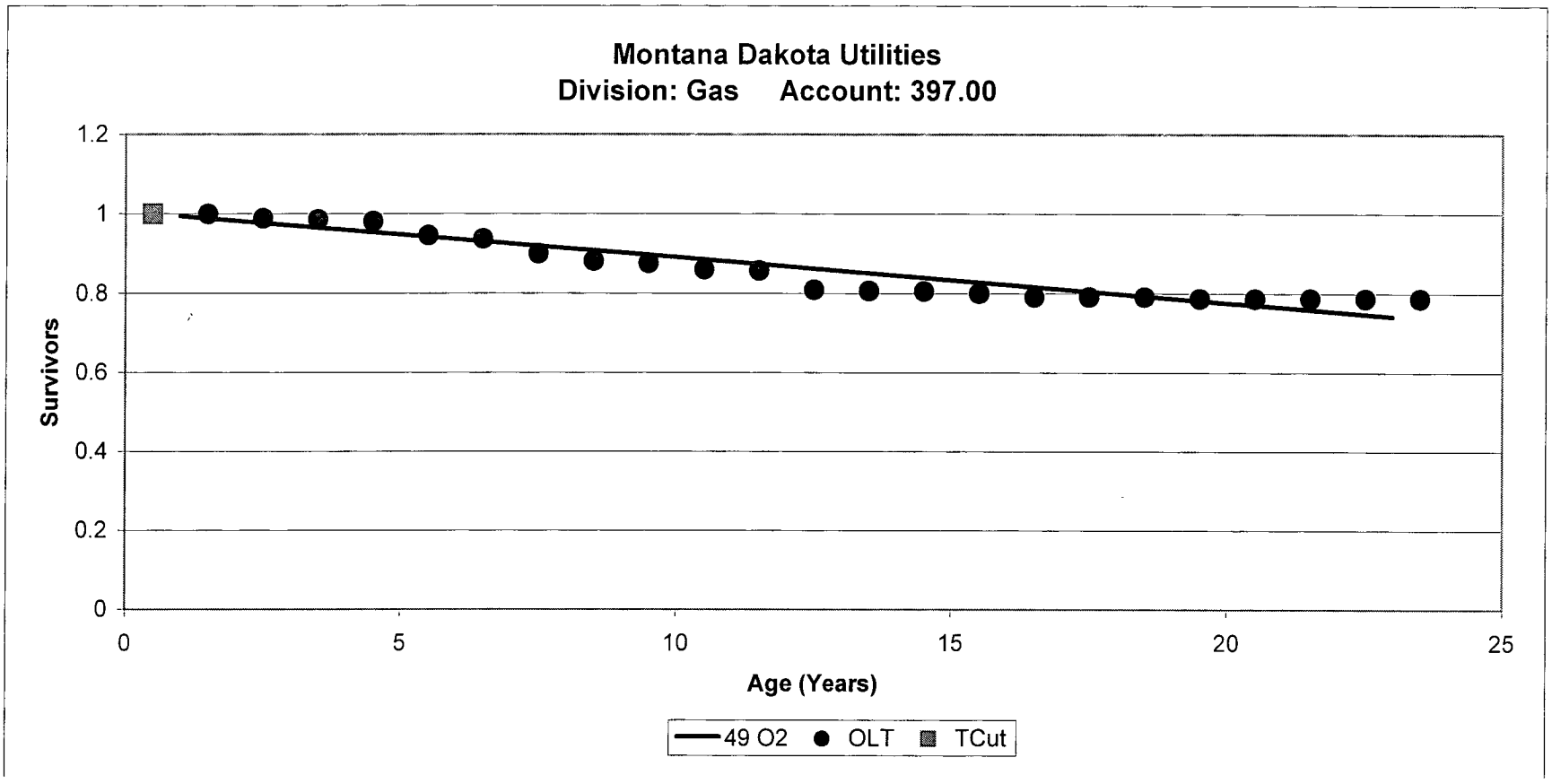
Account: 397
Analytical Parameters
OLT Observation Band: 1978 - 2001
OLT Retirement Band: 1978 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 24 (23.5)



Analytical Parameters
OLT Observation Band: 1978 - 2001
OLT Retirement Band: 1978 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 24 (23.5)



Analytical Parameters
OLT Observation Band: 1978 - 2001
OLT Retirement Band: 1978 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 24 (23.5)



Analytical Parameters
OLT Observation Band: 1978 - 2001
OLT Retirement Band: 1978 - 2001
Minimum Life Expectancy: 10
Maximum Life Expectancy: 200
Life Expectancy Increment: 1
Maximum Observation (T-Cut): 24 (23.5)

[redacted]

[redacted]

[redacted]

U-399-02-183
Exhibit_____(CWK-3)

Age	L0	L0 5	L1	L1 5	L2	L3	L4	L5	O1	O2	O3	O4	R0 5	R1	R1 5	R2	R2 5	R3	R4	R5	S0	S0 5	S-0 5	S1	S1 5	S2	S3	S4	S5	S6	SQ
0.5	0.998378	0.998632	0.999115	0.999508	0.999993	1		1	0.994318	0.994274	0.994077	0.994023	0.994871	0.995947	0.996932	0.998215	0.998917	0.999677	0.999981	1	0.99951	0.999723	0.99643	0.999985	0.999992	1	1	1	1	1	1
1.5	0.99301	0.99446	0.996889	0.99819	0.999838	1	1	1	0.982955	0.982818	0.982246	0.982088	0.98452	0.987583	0.990491	0.994299	0.99648	0.998847	0.999921	1	0.996851	0.998134	0.998646	0.999715	0.99984	0.999996	1	1	1	1	1
2.5	0.98591	0.988891	0.993927	0.996252	0.99928	0.999999	1	1	0.971591	0.971357	0.970438	0.970187	0.974033	0.978865	0.983615	0.98988	0.993631	0.997715	0.999515	1	0.992385	0.995266	0.980148	0.998843	0.999338	0.999952	1	1	1	1	1
3.5	0.977504	0.982227	0.990103	0.993511	0.998107	0.999953	1	1	0.960227	0.959891	0.958654	0.958324	0.963414	0.968793	0.976291	0.984908	0.990306	0.996198	0.999632	1	0.986424	0.991196	0.971058	0.99707	0.998296	0.999782	0.999997	1	1	1	1
4.5	0.968114	0.974582	0.985292	0.98982	0.996117	0.999718	1	1	0.948864	0.948424	0.9469	0.946502	0.952664	0.960366	0.968488	0.97932	0.986435	0.994201	0.999329	1	0.979095	0.985927	0.961444	0.994204	0.996517	0.999337	0.999983	1	1	1	1
5.5	0.957897	0.965996	0.979381	0.985042	0.993188	0.999118	1	1	0.9375	0.936953	0.935173	0.934722	0.941782	0.950588	0.960201	0.973071	0.981937	0.991612	0.998839	1	0.970535	0.979411	0.951342	0.990028	0.993827	0.998408	0.999926	1	1	1	1
6.5	0.946953	0.9565	0.972263	0.979063	0.989166	0.997963	0.999998	1	0.926136	0.925481	0.923478	0.92299	0.930768	0.940463	0.95139	0.966105	0.976725	0.988306	0.998067	1	0.96085	0.971681	0.940786	0.984426	0.990037	0.996733	0.999757	1	1	1	1
7.5	0.93541	0.946137	0.963853	0.971769	0.983995	0.996054	0.999949	1	0.914773	0.914009	0.911816	0.911308	0.919626	0.929996	0.942051	0.958344	0.970694	0.984145	0.996884	1	0.950123	0.96273	0.929819	0.977268	0.984935	0.993998	0.999345	0.999999	1	1	1
8.5	0.923323	0.934918	0.954085	0.963113	0.977586	0.993222	0.999688	1	0.903409	0.902535	0.90019	0.899679	0.908356	0.91919	0.932149	0.949729	0.963747	0.978972	0.995114	1	0.938425	0.952524	0.918463	0.968466	0.978344	0.98988	0.99847	0.99999	1	1	1
9.5	0.910766	0.922838	0.942903	0.953063	0.969912	0.989309	0.99891	1	0.892045	0.891061	0.888604	0.888106	0.896956	0.908051	0.921665	0.940196	0.955771	0.972622	0.99253	0.999993	0.925821	0.941106	0.906731	0.95798	0.970095	0.984044	0.996807	0.999951	1	1	1
10.5	0.897806	0.909947	0.930301	0.941603	0.960802	0.984139	0.997184	1	0.880682	0.879587	0.877055	0.876593	0.885433	0.896579	0.910558	0.929662	0.946647	0.964916	0.988838	0.999945	0.912369	0.928489	0.894657	0.945733	0.960005	0.976155	0.993914	0.999803	1	1	1
11.5	0.884469	0.896273	0.916288	0.928629	0.949783	0.977484	0.993991	0.999982	0.869318	0.868112	0.865555	0.865143	0.873786	0.884761	0.898781	0.918043	0.936246	0.955661	0.983674	0.999742	0.898124	0.914656	0.882261	0.931755	0.947912	0.965898	0.989235	0.999353	1	1	1
12.5	0.870825	0.881828	0.900903	0.91397	0.936363	0.969033	0.988773	0.99975	0.857955	0.856638	0.854097	0.853762	0.862011	0.872575	0.886294	0.905269	0.924434	0.944653	0.97659	0.999124	0.88313	0.899669	0.869552	0.916002	0.933716	0.952991	0.982116	0.998184	0.999996	1	1
13.5	0.856906	0.866668	0.884212	0.897506	0.92008	0.9583	0.980982	0.99865	0.846591	0.845163	0.842691	0.842451	0.850105	0.859996	0.873029	0.891257	0.911059	0.931674	0.967062	0.997615	0.867438	0.883556	0.856551	0.898535	0.91732	0.937181	0.971839	0.995539	0.999964	1	1
14.5	0.842748	0.850852	0.866312	0.879164	0.900788	0.944543	0.970112	0.99548	0.835227	0.833688	0.831335	0.831215	0.838063	0.846995	0.858952	0.875887	0.895969	0.916486	0.954518	0.99449	0.851095	0.86632	0.843279	0.879372	0.898605	0.918281	0.957666	0.990224	0.999789	1	1
15.5	0.828395	0.834428	0.847323	0.85896	0.878335	0.927013	0.955706	0.988641	0.823864	0.822214	0.820034	0.820057	0.825872	0.833544	0.843974	0.859096	0.879009	0.898829	0.938321	0.988753	0.834145	0.848035	0.829746	0.858566	0.877585	0.896188	0.938894	0.980566	0.999059	0.999997	1
16.5	0.813873	0.817461	0.82739	0.836955	0.852963	0.904906	0.937268	0.976442	0.8125	0.810739	0.808794	0.808983	0.813524	0.819612	0.828071	0.840793	0.860007	0.878413	0.917812	0.979162	0.816631	0.828747	0.815965	0.836201	0.854251	0.87085	0.914916	0.964474	0.996623	0.999947	1
17.5	0.799222	0.800039	0.806679	0.813368	0.824865	0.877477	0.914015	0.957372	0.801136	0.799265	0.797609	0.797997	0.801011	0.805168	0.811164	0.820863	0.838779	0.854912	0.892342	0.96414	0.798589	0.808476	0.801956	0.812325	0.82864	0.842289	0.885277	0.939657	0.989928	0.999403	1
18.5	0.784472	0.782246	0.785376	0.788438	0.794468	0.844385	0.884527	0.929759	0.789773	0.78779	0.786497	0.7871	0.788323	0.790185	0.793216	0.799226	0.815128	0.827968	0.861302	0.941456	0.78006	0.787306	0.787731	0.787068	0.800814	0.810596	0.849731	0.903903	0.974339	0.9956	1
19.5	0.769651	0.764152	0.763676	0.762432	0.762184	0.805737	0.846558	0.890411	0.778409	0.776315	0.775446	0.776299	0.775445	0.774635	0.774168	0.775816	0.78885	0.797198	0.824233	0.907971	0.761082	0.765293	0.773297	0.760496	0.77091	0.775938	0.808276	0.855614	0.943217	0.978453	1
20.5	0.754794	0.745854	0.741786	0.73556	0.728494	0.762028	0.797493	0.833587	0.767045	0.764841	0.764469	0.765596	0.762373	0.758495	0.753979	0.750551	0.759711	0.76222	0.780822	0.85981	0.741687	0.742476	0.758673	0.732749	0.739065	0.738523	0.761185	0.794279	0.889447	0.92463	1
21.5	0.739927	0.727433	0.719874	0.708036	0.693879	0.714185	0.735687	0.753305	0.755682	0.753366	0.753565	0.754993	0.7491	0.741744	0.732617	0.723357	0.727549	0.722698	0.729728	0.793023	0.721912	0.718945	0.743872	0.703933	0.705446	0.698681	0.709006	0.720642	0.807951	0.804501	1
22.5	0.725067	0.708971	0.69799	0.680077	0.658782	0.663558	0.662024	0.64909	0.744318	0.741891	0.742736	0.744497	0.73561	0.724372	0.710042	0.694237	0.692223	0.678407	0.688217	0.70507	0.701795	0.694764	0.728901	0.674177	0.670295	0.65677	0.652552	0.636865	0.698771	0.612404	1
23.5	0.866316	0.866316	0.866316	0.866316	0.866316	0.866316	0.866316	0.866316					0.866316	0.866316	0.866316	0.866316	0.866316				0.866316	0.866316	0.866316	0.866316	0.866316	0.866316	0.866316	0.866316	0.866316	0.866316	0.866316

Account 397

Account 380 - Services

Region		Company	ASL	Depreciable Plant Balance (000)	Weighting
[redacted]orth Atlantic	380.00	Redacted	33.0	163,621	5,399,493
North Atlantic	380.10	Redacted	35.0	128,777	4,507,195
North Atlantic	380.23	Redacted	40.0	210,911	8,436,440
North Atlantic	380.00	Redacted	34.0	3,348	113,832
North Atlantic	380.00	Redacted	43.0	14,184	609,912
North Atlantic	380.00	Redacted	40.0	18,531	741,240
North Atlantic	380.00	Redacted	37.0	113,954	4,216,298
North Atlantic	380.00	Redacted	45.0	120,765	5,434,425
North Atlantic	380.00	Redacted	50.0	750,422	37,521,100
North Atlantic	380.00	Redacted	32.0	6,303	201,696
North Atlantic	380.10	Redacted	32.0	8,735	279,520
North Atlantic	380.20	Redacted	32.0	28,488	911,616
North Atlantic	380.00	Redacted	38.0	137,799	5,236,362
North Atlantic	380.00	Redacted	40.0	4,279	171,160
North Atlantic	380.00	Redacted	52.0	326,357	16,970,564
North Atlantic	380.00	Redacted	50.0	74,648	3,732,400
North Atlantic	380.10	Redacted	32.0	36,672	1,173,504
North Atlantic	380.20	Redacted	44.0	279,639	12,304,116
North Atlantic	380.00	Redacted	50.0	256	12,800
North Atlantic	380.00	Redacted	36.0	162,005	5,832,180
North Atlantic	381.10	Redacted	45.0	32,711	1,471,995
North Atlantic	381.20	Redacted	45.0	178,275	8,022,375
North Atlantic	381.30	Redacted	45.0	6,984	314,280
South Atlantic	380.00	Redacted	40.0	35,466	1,418,640
South Atlantic	380.00	Redacted	34.0	54,536	1,854,224
South Atlantic	380.01	Redacted	32.0	1,577	50,464
South Atlantic	380.02	Redacted	24.0	987	23,688
South Atlantic	381.10	Redacted	38.0	17,757	674,766
South Atlantic	381.20	Redacted	38.0	113,385	4,308,630
South Atlantic	381.30	Redacted	38.0	3,832	145,616
South Atlantic	380.10	Redacted	45.0	31,539	1,419,255
South Atlantic	380.20	Redacted	45.0	184,300	8,293,500
South Atlantic	380-30	Redacted	45.0	5,479	246,555
[redacted]orth Central	380.00	Redacted	30.0	74,988	2,249,640
[redacted]rth Central	380.10	Redacted	48.0	14,799	710,352
[redacted]rth Central	380.20	Redacted	40.0	16,569	662,760
North Central	380.30	Redacted	43.0	83,770	3,602,110
North Central	380.00	Redacted	48.0	274,126	13,158,048
North Central	380.10	Redacted	30.0	235	7,050
North Central	380.20	Redacted	52.0	151,014	7,852,728
North Central	380.40	Redacted	40.0	28,621	1,144,840
North Central	380.50	Redacted	37.0	291,107	10,770,959
North Central	380.00	Redacted	57.0	47,784	2,723,688
North Central	380.00	Redacted	35.0	210,226	7,357,910
North Central	380.00	Redacted	43.0	68,159	2,930,837
North Central	380.02	Redacted	36.0	2,022	72,792
North Central	380.04	Redacted	40.0	47,447	1,897,880
North Central	380.05	Redacted	36.0	190,376	6,853,536
North Central	380.06	Redacted	48.0	28	1,344
North Central	380.08	Redacted	41.0	28,944	1,186,704
North Central	380.00	Redacted	34.0	29,347	997,798
North Central	380.00	Redacted	30.0	79,918	2,397,540
North Central	380.00	Redacted	36.0	669,183	24,090,588
North Central	380.00	Redacted	30.0	311,154	9,334,620
North Central	380.01	Redacted	40.0	16,352	654,080
North Central	380.02	Redacted	40.0	161,249	6,449,960
North Central	380.01	Redacted	25.0	103,352	2,583,800
North Central	380.02	Redacted	36.0	3,811	137,196
North Central	380.03	Redacted	24.0	392,368	9,416,832
North Central	380.00	Redacted	34.0	146,185	4,970,290
North Central	380.00	Redacted	32.0	105,332	3,370,624
North Central	380.00	Redacted	37.0	79,378	2,936,986
South Central	380.00	Redacted	47.2	128,547	6,067,418
South Central	380.00	Redacted	50.0	49,047	2,452,350
South Central	380.22	Redacted	40.0	707	28,280
South Central	380.00	Redacted	50.0	20,132	1,006,600
Plateau	380.00	Redacted	50.0	130,670	6,533,500
Pacific Coast	380.00	Redacted	45.0	195,731	8,807,895
Pacific Coast	380.00	Redacted	38.0	1,426,844	54,220,072
[redacted]acific Coast	380.00	Redacted	10.2	154,789	1,578,848
[redacted]nada	380.00	Redacted	63.0	98,112	6,181,056
[redacted].nada	380.00	Redacted	50.0	180,917	9,045,850
	380 00	Weighted Average ASL	39.8	9,269,862	368,495,202

With All ASLs	
Mean	39.6
Weighted Average	39.8
Standard Error	0.995272253
Median	40
Mode	40
Standard Deviation	8.445165112
Sample Variance	71.32081377
Kurtosis	1.452337002
Skewness	-0.26468641
Range	52.8
Minimum	10.2
Maximum	63
Sum	2854.4
Count	72
Confidence Level(95.0%)	1.984517488

Charlie W. King

Gas Account 376 - Mains

Case No. PU-399-02-183
Exhibit____(CWK-4)

Region		Company	ASL	Depreciable Plant Balance (000)	Weighting
[redacted]rth Atlantic	376.10	Redacted	62.5	252,941	15,808,813
[redacted]orth Atlantic	376.20	Redacted	80.0	38,805	3,104,400
North Atlantic	376.00	Redacted	70.0	397,918	27,854,260
North Atlantic	376.31	Redacted	50.0	43,190	2,159,500
North Atlantic	376.00	Redacted	46.0	6,514	299,644
North Atlantic	376.00	Redacted	69.0	29,009	2,001,621
North Atlantic	376.00	Redacted	66.0	26,629	1,757,514
North Atlantic	376.00	Redacted	68.0	263,239	17,900,252
North Atlantic	376.10	Redacted	75.0	546,794	41,009,550
North Atlantic	376.20	Redacted	70.0	25,449	1,781,430
North Atlantic	376.00	Redacted	46.0	12,984	597,264
North Atlantic	376.00	Redacted	60.0	54,865	3,291,900
North Atlantic	376.00	Redacted	55.0	251,854	13,851,970
North Atlantic	376.00	Redacted	52.0	17,717	921,284
North Atlantic	376.00	Redacted	75.0	183,544	13,765,800
North Atlantic	376.40	Redacted	50.0	5,316	265,800
North Atlantic	376.60	Redacted	75.0	251,981	18,898,575
North Atlantic	376.00	Redacted	75.0	106,005	7,950,375
North Atlantic	376.10	Redacted	55.0	296,464	16,305,520
North Atlantic	376.20	Redacted	64.0	22,090	1,413,760
North Atlantic	376.30	Redacted	53.0	158,005	8,374,265
North Atlantic	376.00	Redacted	75.0	497	37,275
North Atlantic	376.10	Redacted	60.0	143,851	8,631,060
North Atlantic	376.20	Redacted	75.0	5,682	426,150
North Atlantic	376.30	Redacted	50.0	93,163	4,658,150
North Atlantic	376.50	Redacted	60.0	485	29,100
North Atlantic	376.10	Redacted	55.0	1,144	62,920
North Atlantic	376.20	Redacted	55.0	96,236	5,292,980
North Atlantic	376.30	Redacted	55.0	3	165
North Atlantic	376.40	Redacted	55.0	183,848	10,111,640
South Atlantic	376.00	Redacted	66.0	81,684	5,391,144
South Atlantic	376.00	Redacted	63.0	108,048	6,807,024
South Atlantic	376.01	Redacted	37.0	2,745	101,565
South Atlantic	376.02	Redacted	30.0	9,560	286,800
[redacted]outh Atlantic	376.10	Redacted	75.0	6,904	517,800
[redacted]uth Atlantic	376.20	Redacted	57.0	59,126	3,370,182
[redacted]uth Atlantic	376.40	Redacted	57.0	69,983	3,989,031
[redacted]outh Atlantic	376.50	Redacted	57.0	84	4,788
South Atlantic	376.10	Redacted	50.0	678	33,900
South Atlantic	376.20	Redacted	50.0	96,952	4,847,600
South Atlantic	376.30	Redacted	50.0	-	-
South Atlantic	376.40	Redacted	50.0	225,115	11,255,750
South Atlantic	376.50	Redacted	50.0	-	-
North Central	376.00	Redacted	43.1	79,003	3,405,029
North Central	376.10	Redacted	70.0	28,098	1,966,860
North Central	376.20	Redacted	62.0	232,787	14,432,794
North Central	376.30	Redacted	50.0	16,945	847,250
North Central	376.00	Redacted	72.0	549,624	39,572,928
North Central	376.00	Redacted	65.0	116	7,540
North Central	376.10	Redacted	65.0	4,270	277,550
North Central	376.20	Redacted	68.0	327,136	22,245,248
North Central	376.30	Redacted	58.0	10,309	597,922
North Central	376.40	Redacted	65.0	17	1,105
North Central	376.50	Redacted	55.0	358,672	19,726,960
North Central	376.00	Redacted	57.0	125,668	7,163,076
North Central	376.80	Redacted	26.0	-	-
North Central	376.00	Redacted	45.0	316,847	14,258,115
North Central	376.00	Redacted	50.0	120,918	6,045,900
North Central	376.01	Redacted	50.0	2,552	127,600
North Central	376.01	Redacted	34.0	2,870	97,580
North Central	376.02	Redacted	53.0	6,176	327,328
North Central	376.04	Redacted	46.0	263,201	12,107,246
North Central	376.05	Redacted	50.0	156,287	7,814,350
North Central	376.06	Redacted	70.0	46,802	3,276,140
North Central	376.09	Redacted	61.0	309	18,849
North Central	376.00	Redacted	36.0	73,588	2,649,168
North Central	376.10	Redacted	45.0	113,436	5,104,620
North Central	376.30	Redacted	45.0	3,164	142,380
North Central	376.00	Redacted	47.0	1,320,129	62,046,063
North Central	376.00	Redacted	47.0	328,015	15,416,705
North Central	376.01	Redacted	45.0	73,235	3,295,575
[redacted]rth Central	376.02	Redacted	45.0	165,803	7,461,135
[redacted]th Central	376.11	Redacted	69.0	69	4,761
[redacted].th Central	376.12	Redacted	67.0	28,272	1,894,224
North Central	376.13	Redacted	75.0	57,617	4,321,275
North Central	376.14	Redacted	50.0	59,828	2,991,400

With All ASLs	
Mean	54.6
Weighted Average	54.2
Standard Error	1.291903443
Median	54
Mode	50
Standard Deviation	12.91903443
Sample Variance	166.9014505
Kurtosis	1.178349587
Skewness	-0.556584925
Range	70
Minimum	10
Maximum	80
Sum	5464.2
Count	100
Confidence Level(95.0%)	2.563417169

Region		Company	ASL	Depreciable Plant Balance (000)	Weighting
[redacted]rth Central	376.15	Redacted	50.0	36,222	1,811,100
[redacted]orth Central	376.16	Redacted	50.0	388,321	19,416,050
North Central	376.20	Redacted	66.4	3,531	234,458
North Central	376.30	Redacted	49.0	19,283	944,867
North Central	375.10	Redacted	43.0	151,188	6,501,084
North Central	375.20	Redacted	43.0	155	6,665
North Central	375.30	Redacted	43.0	89	3,827
North Central	375.40	Redacted	43.0	62,024	2,667,032
North Central	375.50	Redacted	43.0	2,157	92,751
North Central	376.00	Redacted	40.0	186,109	7,444,360
North Central	376.00	Redacted	47.0	129,183	6,071,601
South Central	376.10	Redacted	51.0	202,077	10,305,927
South Central	376.30	Redacted	10.0	3,849	38,490
South Central	376.10	Redacted	50.0	80,171	4,008,550
South Central	376.22	Redacted	40.0	1,779	71,160
South Central	376.30	Redacted	50.0	2,530	126,500
South Central	376.10	Redacted	55.0	51,934	2,856,370
South Central	376.30	Redacted	55.0	-	-
Plateau	376.00	Redacted	65.0	272,809	17,732,585
Pacific Coast	376.00	Redacted	51.0	357,452	18,230,052
Pacific Coast	376.00	Redacted	42.0	1,929,536	81,040,512
Pacific Coast	376.00	Redacted	13.2	200,950	2,652,540
Canada	376.00	Redacted	65.0	185,318	12,045,670
Canada	376.00	Redacted	65.0	267,596	17,393,740
		Weighted Average ASL	54.2	13,583,127	736,509,088

Charles W. King

Docket No. PU-399-02-183
Exhibit_____(CWK-5)

AUS Consultants
Simulated Plant Record ("SPR") Output Summaries
(Full Record Data)

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS
Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	84
Interval Between Test Points -	1
First Test Point -	1918
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	181.31 Yrs.	1.6869E+09	53.87	18.56	45.54
O3	131.94 Yrs.	1.8012E+09	52.13	19.18	46.81
SC	82.78 Yrs.	2.1136E+09	48.12	20.78	50.43
O1	82.78 Yrs.	2.1136E+09	48.12	20.78	50.43
O2	93.03 Yrs.	2.1165E+09	48.09	20.80	50.42
R0.5	72.22 Yrs.	3.2362E+09	38.89	25.71	58.44
S.5	72.12 Yrs.	4.6201E+09	32.55	30.72	59.39
L0	81.20 Yrs.	5.1597E+09	30.80	32.47	56.73
R1	64.53 Yrs.	5.9166E+09	28.76	34.77	69.80
L0.5	73.59 Yrs.	8.1542E+09	24.50	40.82	62.64
S0	65.06 Yrs.	9.9966E+09	22.13	45.19	69.30
R1.5	60.22 Yrs.	1.0167E+10	21.94	45.58	80.98
L1	67.84 Yrs.	1.3226E+10	19.24	51.98	68.62
S0.5	61.38 Yrs.	1.4631E+10	18.29	54.67	77.23
R2	57.00 Yrs.	1.6809E+10	17.06	58.60	90.67
L1.5	63.47 Yrs.	1.8011E+10	16.48	60.66	75.41
S1	58.47 Yrs.	2.1310E+10	15.15	65.98	84.73
R2.5	54.88 Yrs.	2.3437E+10	14.45	69.20	96.37
L2	60.06 Yrs.	2.5223E+10	13.93	71.79	81.38
S1.5	56.41 Yrs.	2.6714E+10	13.54	73.88	90.77
R3	53.09 Yrs.	3.1578E+10	12.45	80.32	99.68
S2	54.69 Yrs.	3.3609E+10	12.07	82.87	95.58
L3	55.19 Yrs.	3.5761E+10	11.70	85.48	91.42
R4	50.81 Yrs.	4.1670E+10	10.84	92.27	100.00
S3	52.28 Yrs.	4.2480E+10	10.73	93.16	99.54
L4	51.69 Yrs.	4.2881E+10	10.68	93.60	98.96
S6	48.25 Yrs.	4.3910E+10	10.56	94.72	100.00
R5	49.12 Yrs.	4.5237E+10	10.40	96.14	100.00
SQ	47.00 Yrs.	4.5238E+10	10.40	96.14	100.00
S5	48.94 Yrs.	4.5772E+10	10.34	96.71	100.00
L5	49.88 Yrs.	4.5880E+10	10.33	96.82	99.98
S4	50.25 Yrs.	4.6839E+10	10.22	97.83	100.00

Montana-Dakota Utilities Company
Gas Division
376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	86
Interval Between Test Points -	1
First Test Point -	1916
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	193.69 Yrs.	3.6515E+13	31.73	31.52	44.13
O3	140.06 Yrs.	3.7019E+13	31.51	31.73	45.48
SC	86.66 Yrs.	3.8245E+13	31.00	32.25	49.33
O1	86.66 Yrs.	3.8245E+13	31.00	32.25	49.33
O2	97.38 Yrs.	3.8264E+13	31.00	32.26	49.33
R0.5	72.94 Yrs.	4.2225E+13	29.51	33.89	59.47
S.5	70.41 Yrs.	4.7711E+13	27.76	36.03	62.73
R1	62.12 Yrs.	5.0127E+13	27.08	36.93	75.98
L0	78.11 Yrs.	5.0783E+13	26.91	37.17	60.25
L0.5	68.28 Yrs.	5.8769E+13	25.01	39.98	68.93
R1.5	55.59 Yrs.	6.0239E+13	24.70	40.48	90.64
S0	59.44 Yrs.	6.3822E+13	24.00	41.67	79.00
L1	60.53 Yrs.	7.1239E+13	22.72	44.02	77.99
R2	50.53 Yrs.	7.3630E+13	22.34	44.75	99.06
S0.5	54.50 Yrs.	7.3937E+13	22.30	44.85	89.28
L1.5	55.38 Yrs.	8.0707E+13	21.34	46.86	85.71
R2.5	47.41 Yrs.	8.3046E+13	21.04	47.53	99.98
S1	50.50 Yrs.	8.7428E+13	20.51	48.77	96.76
L2	51.16 Yrs.	9.5097E+13	19.66	50.86	91.88
R3	44.84 Yrs.	9.5224E+13	19.65	50.90	100.00
S1.5	48.00 Yrs.	9.5699E+13	19.60	51.02	99.24
S2	45.81 Yrs.	1.0630E+14	18.60	53.77	99.98
L3	46.09 Yrs.	1.1413E+14	17.95	55.72	98.69
R4	42.44 Yrs.	1.1500E+14	17.88	55.93	100.00
S3	43.31 Yrs.	1.1941E+14	17.55	56.99	100.00
L4	42.91 Yrs.	1.2801E+14	16.95	59.01	100.00
S4	41.66 Yrs.	1.3445E+14	16.54	60.48	100.00
R5	41.09 Yrs.	1.4229E+14	16.07	62.21	100.00
L5	41.47 Yrs.	1.4233E+14	16.07	62.22	100.00
S5	40.88 Yrs.	1.4994E+14	15.66	63.86	100.00
S6	40.47 Yrs.	1.6348E+14	15.00	66.69	100.00
SQ	40.00 Yrs.	1.7606E+14	14.45	69.21	100.00

Montana-Dakota Utilities Company

Gas Division

378.00 MEAS. & REG. STATION EQUIP. - GENERAL

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	82
Interval Between Test Points -	1
First Test Point -	1920
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	97.97 Yrs.	2.3970E+10	28.38	35.23	64.73
O3	72.59 Yrs.	2.4978E+10	27.81	35.96	68.40
O2	53.66 Yrs.	2.8772E+10	25.91	38.60	79.73
SC	47.97 Yrs.	2.9535E+10	25.57	39.11	84.95
O1	47.97 Yrs.	2.9535E+10	25.57	39.11	84.95
L0	48.38 Yrs.	3.3691E+10	23.94	41.77	84.66
R0.5	44.28 Yrs.	3.5901E+10	23.19	43.12	95.29
S.5	44.16 Yrs.	3.6617E+10	22.96	43.55	94.92
L0.5	45.09 Yrs.	3.8003E+10	22.54	44.36	90.00
R1	41.38 Yrs.	4.3276E+10	21.12	47.34	99.92
L1	42.38 Yrs.	4.3412E+10	21.09	47.41	94.45
S0	41.22 Yrs.	4.5503E+10	20.60	48.54	99.92
L1.5	40.44 Yrs.	4.6655E+10	20.34	49.15	97.07
R1.5	39.47 Yrs.	4.7650E+10	20.13	49.67	100.00
S0.5	39.59 Yrs.	4.9630E+10	19.73	50.70	100.00
S6	33.31 Yrs.	4.9691E+10	19.71	50.73	100.00
S5	33.56 Yrs.	4.9753E+10	19.70	50.76	100.00
L2	38.75 Yrs.	5.0199E+10	19.61	50.99	98.85
L5	33.94 Yrs.	5.0373E+10	19.58	51.07	100.00
R5	33.72 Yrs.	5.0835E+10	19.49	51.31	100.00
R2	37.81 Yrs.	5.1086E+10	19.44	51.43	100.00
S4	34.06 Yrs.	5.1268E+10	19.41	51.53	100.00
L4	34.75 Yrs.	5.1952E+10	19.28	51.87	100.00
R2.5	36.69 Yrs.	5.1963E+10	19.28	51.87	100.00
L3	36.41 Yrs.	5.2619E+10	19.16	52.20	99.99
R4	34.50 Yrs.	5.2756E+10	19.13	52.27	100.00
SQ	33.00 Yrs.	5.2847E+10	19.12	52.31	100.00
R3	35.66 Yrs.	5.2961E+10	19.10	52.37	100.00
S1	38.16 Yrs.	5.3327E+10	19.03	52.55	100.00
S3	35.00 Yrs.	5.3490E+10	19.00	52.63	100.00
S1.5	37.12 Yrs.	5.4032E+10	18.91	52.90	100.00
S2	36.19 Yrs.	5.4701E+10	18.79	53.22	100.00

Montana-Dakota Utilities Company

Gas Division

379.00 MEAS. & REG. STATION EQUIP. - CITY GATE

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	51
Interval Between Test Points -	1
First Test Point -	1951
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	81.47 Yrs.	8.9177E+10	15.61	64.06	55.51
O3	61.03 Yrs.	1.0584E+11	14.33	69.78	57.03
O2	46.06 Yrs.	1.5240E+11	11.94	83.74	61.29
O1	41.03 Yrs.	1.5288E+11	11.92	83.87	61.54
SC	41.03 Yrs.	1.5288E+11	11.92	83.87	61.54
R0.5	39.16 Yrs.	2.4943E+11	9.33	107.13	66.98
L0	43.42 Yrs.	2.5106E+11	9.30	107.48	63.74
S.5	39.56 Yrs.	2.7712E+11	8.86	112.92	66.34
L0.5	41.81 Yrs.	3.6703E+11	7.70	129.95	66.63
R1	38.00 Yrs.	3.9595E+11	7.41	134.98	72.47
S0	38.59 Yrs.	4.5122E+11	6.94	144.09	70.93
L1	40.50 Yrs.	5.1626E+11	6.49	154.12	69.53
R1.5	37.66 Yrs.	5.7404E+11	6.15	162.52	77.41
S0.5	38.25 Yrs.	6.1493E+11	5.95	168.21	74.50
L1.5	39.91 Yrs.	7.0379E+11	5.56	179.95	72.67
R2	37.44 Yrs.	7.9447E+11	5.23	191.19	82.12
S1	37.97 Yrs.	8.1308E+11	5.17	193.42	78.03
L2	39.44 Yrs.	9.3833E+11	4.81	207.78	75.66
S1.5	37.94 Yrs.	1.0086E+12	4.64	215.43	81.34
R2.5	37.56 Yrs.	1.0312E+12	4.59	217.83	86.35
S2	37.88 Yrs.	1.2354E+12	4.19	238.42	84.73
R3	37.66 Yrs.	1.3045E+12	4.08	244.99	90.71
L3	38.72 Yrs.	1.3926E+12	3.95	253.13	82.06
S3	38.03 Yrs.	1.6483E+12	3.63	275.39	90.66
R4	38.13 Yrs.	1.8007E+12	3.47	287.85	96.74
L4	38.41 Yrs.	1.8656E+12	3.41	292.98	89.90
S4	38.34 Yrs.	2.1301E+12	3.19	313.06	96.67
L5	38.63 Yrs.	2.3004E+12	3.07	325.34	95.45
R5	38.72 Yrs.	2.3752E+12	3.02	330.59	99.75
S5	38.81 Yrs.	2.5400E+12	2.93	341.86	99.54
S6	39.31 Yrs.	2.8400E+12	2.77	361.49	100.00
SQ	39.00 Yrs.	3.1011E+12	2.65	377.74	100.00

Montana-Dakota Utilities Company

Gas Division

380.00 SERVICES

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	82
Interval Between Test Points -	1
First Test Point -	1920
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	165.84 Yrs.	1.4210E+12	57.46	17.40	47.72
O3	119.97 Yrs.	1.4459E+12	56.96	17.56	49.47
O1	74.31 Yrs.	1.5105E+12	55.73	17.94	54.84
SC	74.31 Yrs.	1.5105E+12	55.73	17.94	54.84
O2	83.50 Yrs.	1.5113E+12	55.72	17.95	54.77
R0.5	62.72 Yrs.	1.7128E+12	52.34	19.11	67.60
S.5	60.47 Yrs.	2.0035E+12	48.39	20.66	70.42
R1	53.59 Yrs.	2.0865E+12	47.42	21.09	85.73
L0	66.94 Yrs.	2.2102E+12	46.07	21.70	66.41
R1.5	48.00 Yrs.	2.4723E+12	43.56	22.96	96.88
L0.5	58.50 Yrs.	2.5915E+12	42.55	23.50	75.67
S0	51.06 Yrs.	2.8841E+12	40.33	24.79	87.66
R2	43.59 Yrs.	2.9318E+12	40.00	25.00	100.00
R2.5	40.84 Yrs.	3.2226E+12	38.16	26.21	100.00
L1	51.81 Yrs.	3.2370E+12	38.07	26.27	84.72
S0.5	46.84 Yrs.	3.3130E+12	37.63	26.57	95.98
L1.5	47.41 Yrs.	3.6004E+12	36.10	27.70	91.36
R3	38.56 Yrs.	3.8013E+12	35.13	28.46	100.00
S1	43.31 Yrs.	3.8865E+12	34.74	28.78	99.75
S1.5	41.12 Yrs.	4.0871E+12	33.88	29.52	100.00
L2	43.69 Yrs.	4.1972E+12	33.43	29.91	96.16
S2	39.19 Yrs.	4.4402E+12	32.51	30.76	100.00
L3	39.25 Yrs.	4.7446E+12	31.45	31.80	99.86
S3	36.94 Yrs.	4.8460E+12	31.12	32.14	100.00
R4	36.25 Yrs.	4.8575E+12	31.08	32.18	100.00
L4	36.44 Yrs.	4.9923E+12	30.66	32.62	100.00
L5	35.06 Yrs.	5.2181E+12	29.99	33.35	100.00
S4	35.34 Yrs.	5.2312E+12	29.95	33.39	100.00
S6	34.00 Yrs.	5.3404E+12	29.64	33.74	100.00
S5	34.47 Yrs.	5.3551E+12	29.60	33.78	100.00
R5	34.75 Yrs.	5.4225E+12	29.41	34.00	100.00
SQ	34.00 Yrs.	5.5950E+12	28.96	34.53	100.00

Montana-Dakota Utilities Company

Gas Division

381.00 METERS

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	69
Interval Between Test Points -	1
First Test Point -	1933
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	120.50 Yrs.	5.3827E+12	31.84	31.41	52.63
O3	87.69 Yrs.	5.5858E+12	31.25	32.00	54.82
O2	61.88 Yrs.	6.1182E+12	29.86	33.49	61.86
SC	55.06 Yrs.	6.1188E+12	29.86	33.49	62.20
O1	55.06 Yrs.	6.1188E+12	29.86	33.49	62.20
R0.5	47.91 Yrs.	7.5820E+12	26.82	37.28	75.64
S.5	47.31 Yrs.	9.0156E+12	24.60	40.65	75.97
L0	52.80 Yrs.	9.5412E+12	23.91	41.82	70.13
R1	42.50 Yrs.	1.0194E+13	23.13	43.23	90.80
L0.5	47.44 Yrs.	1.2022E+13	21.30	46.94	77.87
R1.5	39.25 Yrs.	1.3299E+13	20.25	49.37	97.97
S0	41.97 Yrs.	1.3712E+13	19.95	50.13	89.41
L1	43.25 Yrs.	1.5704E+13	18.64	53.65	85.12
S0.5	39.31 Yrs.	1.6828E+13	18.00	55.54	96.05
R2	36.72 Yrs.	1.7371E+13	17.72	56.43	100.00
L1.5	40.25 Yrs.	1.8527E+13	17.16	58.28	90.88
R2.5	35.09 Yrs.	2.0760E+13	16.21	61.69	100.00
S1	37.12 Yrs.	2.0826E+13	16.19	61.79	99.48
L2	37.81 Yrs.	2.2378E+13	15.61	64.05	95.19
S1.5	35.69 Yrs.	2.3333E+13	15.29	65.40	99.96
R3	33.72 Yrs.	2.4803E+13	14.83	67.43	100.00
S2	34.41 Yrs.	2.6373E+13	14.38	69.53	100.00
L3	34.56 Yrs.	2.6968E+13	14.22	70.31	99.57
R4	32.16 Yrs.	2.9444E+13	13.61	73.47	100.00
S3	32.78 Yrs.	2.9489E+13	13.60	73.52	100.00
L4	32.44 Yrs.	2.9745E+13	13.54	73.84	100.00
SQ	30.00 Yrs.	2.9797E+13	13.53	73.91	100.00
S6	30.44 Yrs.	3.0038E+13	13.48	74.20	100.00
L5	31.31 Yrs.	3.0491E+13	13.38	74.76	100.00
S5	30.84 Yrs.	3.0551E+13	13.36	74.83	100.00
S4	31.56 Yrs.	3.0748E+13	13.32	75.08	100.00
R5	31.06 Yrs.	3.0906E+13	13.29	75.27	100.00

Montana-Dakota Utilities Company

Gas Division

383.00 HOUSE REGULATORS

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	56
Interval Between Test Points -	1
First Test Point -	1946
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O3	77.75 Yrs.	7.4947E+10	46.30	21.60	51.35
O4	106.59 Yrs.	7.5393E+10	46.16	21.66	49.67
O2	55.12 Yrs.	7.5771E+10	46.05	21.72	56.46
SC	49.06 Yrs.	7.5840E+10	46.02	21.73	56.56
O1	49.06 Yrs.	7.5840E+10	46.02	21.73	56.56
L0	48.03 Yrs.	8.2838E+10	44.04	22.71	63.37
R0.5	43.19 Yrs.	8.3500E+10	43.86	22.80	66.69
S.5	42.97 Yrs.	8.6797E+10	43.02	23.24	67.21
L0.5	43.66 Yrs.	1.0490E+11	39.13	25.55	69.90
R1	38.97 Yrs.	1.1148E+11	37.96	26.34	79.40
S0	38.84 Yrs.	1.3043E+11	35.10	28.49	78.42
L1	40.22 Yrs.	1.4517E+11	33.27	30.06	76.45
R1.5	36.56 Yrs.	1.6279E+11	31.41	31.83	89.57
S0.5	36.78 Yrs.	1.7965E+11	29.90	33.44	86.22
L1.5	37.81 Yrs.	1.8938E+11	29.13	34.33	82.66
R2	34.69 Yrs.	2.4053E+11	25.84	38.69	96.89
S1	35.09 Yrs.	2.4810E+11	25.45	39.30	92.85
L2	35.84 Yrs.	2.5048E+11	25.33	39.49	87.97
S1.5	34.00 Yrs.	3.0639E+11	22.90	43.67	96.60
R2.5	33.53 Yrs.	3.1633E+11	22.54	44.37	99.18
L3	33.22 Yrs.	3.4743E+11	21.50	46.50	95.85
S2	33.00 Yrs.	3.7288E+11	20.76	48.18	99.10
R3	32.47 Yrs.	3.9953E+11	20.05	49.87	100.00
L4	31.50 Yrs.	4.3412E+11	19.24	51.98	99.82
S3	31.78 Yrs.	4.5042E+11	18.89	52.95	99.98
L5	30.66 Yrs.	4.6441E+11	18.60	53.77	100.00
SQ	30.00 Yrs.	4.6710E+11	18.55	53.92	100.00
S6	29.97 Yrs.	4.6743E+11	18.54	53.94	100.00
S5	30.28 Yrs.	4.7752E+11	18.34	54.52	100.00
R4	31.25 Yrs.	4.8191E+11	18.26	54.77	100.00
S4	30.81 Yrs.	4.8222E+11	18.25	54.79	100.00
R5	30.41 Yrs.	4.8665E+11	18.17	55.04	100.00

Montana-Dakota Utilities Company

Gas Division

385.00 IND. MEAS. & REG. STA. EQUIP.

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	51
Interval Between Test Points -	1
First Test Point -	1951
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	113.78 Yrs.	8.3177E+08	55.77	17.93	44.31
O3	82.66 Yrs.	8.4879E+08	55.21	18.11	45.51
O1	51.66 Yrs.	9.0168E+08	53.56	18.67	48.88
SC	51.66 Yrs.	9.0168E+08	53.56	18.67	48.88
O2	58.06 Yrs.	9.0208E+08	53.55	18.67	48.87
R0.5	44.62 Yrs.	1.0838E+09	48.86	20.47	56.87
S.5	43.97 Yrs.	1.2021E+09	46.39	21.56	58.85
L0	49.01 Yrs.	1.2353E+09	45.76	21.85	56.84
L0.5	43.94 Yrs.	1.4805E+09	41.80	23.92	63.46
R1	39.44 Yrs.	1.5171E+09	41.29	24.22	68.77
S0	38.75 Yrs.	1.8356E+09	37.54	26.64	70.59
L1	39.91 Yrs.	1.8788E+09	37.11	26.95	70.55
R1.5	36.50 Yrs.	2.2312E+09	34.05	29.37	80.75
S0.5	36.34 Yrs.	2.3920E+09	32.89	30.41	79.13
L1.5	37.34 Yrs.	2.4822E+09	32.28	30.98	77.30
S1	34.41 Yrs.	3.1647E+09	28.59	34.98	87.12
L2	35.22 Yrs.	3.2661E+09	28.14	35.53	83.38
R2	34.31 Yrs.	3.3331E+09	27.86	35.89	91.09
S1.5	33.31 Yrs.	4.0302E+09	25.34	39.47	92.47
R2.5	33.09 Yrs.	4.7268E+09	23.39	42.74	96.53
S2	32.34 Yrs.	5.0947E+09	22.53	44.38	96.70
L3	32.78 Yrs.	5.5960E+09	21.50	46.51	92.34
R3	32.06 Yrs.	6.4492E+09	20.03	49.93	99.71
S3	31.44 Yrs.	7.7406E+09	18.28	54.70	99.60
L4	31.44 Yrs.	9.1643E+09	16.80	59.52	98.86
R4	31.19 Yrs.	9.8623E+09	16.20	61.74	100.00
S4	31.00 Yrs.	1.1958E+10	14.71	67.99	100.00
L5	31.00 Yrs.	1.3210E+10	13.99	71.46	99.94
R5	30.88 Yrs.	1.4489E+10	13.36	74.84	100.00
S5	30.88 Yrs.	1.5830E+10	12.78	78.22	100.00
S6	30.81 Yrs.	1.8367E+10	11.87	84.26	100.00
SQ	31.00 Yrs.	2.1011E+10	11.10	90.12	100.00

Montana-Dakota Utilities Company

Gas Division

386.10 MISC. PROPERTY ON CUSTOMERS PREMISE

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1997
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
L3	65.00 Yrs.	0.0000E+00	.00	.00	.00
L4	20.00 Yrs.	0.0000E+00	.00	.00	.00
S6	16.00 Yrs.	0.0000E+00	.00	.00	.00
S5	16.00 Yrs.	0.0000E+00	.00	.00	.00
R5	16.00 Yrs.	0.0000E+00	.00	.00	.00
L5	16.00 Yrs.	0.0000E+00	.00	.00	.00
SQ	16.00 Yrs.	0.0000E+00	.00	.00	.00
S4	17.00 Yrs.	4.0101E-08	757497.72	.00	.00
S3	59.00 Yrs.	4.0101E-08	757497.72	.00	.00
S2	201.00 Yrs.	7.4669E-08	.00	.00	.00
S1.5	201.00 Yrs.	6.6607E-04	.00	.00	.00
L2	201.00 Yrs.	8.0271E-04	.00	.00	.00
R4	201.00 Yrs.	2.3200E-03	.00	.00	.00
S1	201.00 Yrs.	2.6341E-03	.00	.00	.00
R3	201.00 Yrs.	7.5048E-01	.00	.00	.04
S0.5	201.00 Yrs.	9.3068E-01	.00	.00	.05
L1.5	201.00 Yrs.	2.7503E+00	.00	.00	.07
S0	201.00 Yrs.	3.5279E+00	.00	.00	.09
R2.5	201.00 Yrs.	9.1267E+00	.00	.00	.13
L1	201.00 Yrs.	1.0822E+01	.00	.00	.14
R2	201.00 Yrs.	2.6784E+01	.00	.00	.22
L0.5	201.00 Yrs.	3.3959E+01	.00	.00	.26
L0	206.00 Yrs.	6.5581E+01	.00	.00	.36
R1.5	201.00 Yrs.	9.1417E+01	.00	.00	.40
R1	201.00 Yrs.	1.9451E+02	.00	.00	.58
S.5	201.00 Yrs.	2.0582E+02	.00	.00	.60
R0.5	201.00 Yrs.	4.1586E+02	.00	.00	.85
O1	201.00 Yrs.	7.2031E+02	.00	.00	1.12
SC	201.00 Yrs.	7.2031E+02	.00	.00	1.12
O2	201.00 Yrs.	9.0704E+02	.00	.00	1.26
O3	201.00 Yrs.	1.9774E+03	.00	.00	1.85
O4	201.00 Yrs.	3.8607E+03	.00	.00	2.59

Montana-Dakota Utilities Company

Gas Division

386.20 OTHER PROPERTY ON CUSTOMERS PREMISE

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	10
Interval Between Test Points -	1
First Test Point -	1992
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
S3	159.00 Yrs.	2.0329E-20	321130.00	.00	.00
SQ	16.00 Yrs.	2.0329E-20	321130.00	.00	.00
S6	16.00 Yrs.	2.0329E-20	321130.00	.00	.00
L3	136.00 Yrs.	2.0329E-20	321130.00	.00	.00
L4	42.00 Yrs.	2.0329E-20	321130.00	.00	.00
L5	23.00 Yrs.	2.0329E-20	321130.00	.00	.00
R5	30.00 Yrs.	2.0329E-20	321130.00	.00	.00
S5	21.00 Yrs.	1.2668E-04	516906.61	.00	.00
S4	37.00 Yrs.	1.2668E-04	516906.61	.00	.00
S2	201.00 Yrs.	2.1539E-01	.00	.00	.00
R4	201.00 Yrs.	9.9138E+02	.00	.00	.01
S1.5	201.00 Yrs.	1.3718E+03	.00	.00	.01
L2	201.00 Yrs.	1.9361E+03	.00	.00	.01
S1	201.00 Yrs.	5.3998E+03	.00	.00	.02
R3	201.00 Yrs.	2.9336E+05	.00	.00	.09
S0.5	201.00 Yrs.	6.9859E+05	.00	.00	.17
L1.5	201.00 Yrs.	1.1378E+06	.00	.00	.17
S0	201.00 Yrs.	2.5567E+06	.00	.00	.31
R2.5	201.00 Yrs.	3.3746E+06	.00	.00	.28
L1	201.00 Yrs.	4.3739E+06	.00	.00	.34
R2	201.00 Yrs.	9.8113E+06	.00	.00	.48
L0.5	201.00 Yrs.	1.5927E+07	.00	.00	.68
L0	206.00 Yrs.	3.2471E+07	.00	.00	.98
R1.5	201.00 Yrs.	3.2883E+07	.00	.00	.86
R1	201.00 Yrs.	6.9496E+07	.00	.00	1.25
S.5	201.00 Yrs.	7.6420E+07	.00	.00	1.34
R0.5	201.00 Yrs.	1.4693E+08	.00	.00	1.81
O1	201.00 Yrs.	2.5301E+08	.00	.00	2.36
SC	201.00 Yrs.	2.5301E+08	.00	.00	2.36
O2	201.00 Yrs.	3.1870E+08	.00	.00	2.65
O3	201.00 Yrs.	6.9342E+08	.00	.00	3.91
O4	201.00 Yrs.	1.3512E+09	.00	.00	5.45

Montana-Dakota Utilities Company

Gas Division

387.10 CATHODIC PROTECTION EQUIP.

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	54
Interval Between Test Points -	1
First Test Point -	1948
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	43.38 Yrs.	4.2167E+10	17.05	58.66	75.00
O3	32.72 Yrs.	4.5741E+10	16.37	61.09	80.29
O2	25.09 Yrs.	5.5928E+10	14.80	67.55	91.81
O1	22.75 Yrs.	6.1477E+10	14.12	70.83	100.00
SC	22.75 Yrs.	6.1477E+10	14.12	70.83	100.00
L0	23.27 Yrs.	6.9136E+10	13.31	75.11	96.51
R0.5	21.53 Yrs.	7.1604E+10	13.08	76.44	100.00
S.5	21.53 Yrs.	7.5515E+10	12.74	78.50	100.00
L0.5	22.09 Yrs.	7.9528E+10	12.41	80.56	98.52
R1	20.47 Yrs.	8.1058E+10	12.30	81.33	100.00
R1.5	19.78 Yrs.	8.6937E+10	11.87	84.23	100.00
S0	20.53 Yrs.	9.0376E+10	11.64	85.88	100.00
L1	21.09 Yrs.	9.1499E+10	11.57	86.41	99.74
R2	19.19 Yrs.	9.3456E+10	11.45	87.33	100.00
R2.5	18.78 Yrs.	9.6963E+10	11.24	88.95	100.00
S0.5	19.91 Yrs.	9.6985E+10	11.24	88.96	100.00
SQ	17.00 Yrs.	9.8415E+10	11.16	89.61	100.00
S6	17.47 Yrs.	9.9292E+10	11.11	90.01	100.00
L1.5	20.38 Yrs.	9.9406E+10	11.10	90.06	99.93
R3	18.41 Yrs.	1.0156E+11	10.99	91.03	100.00
S1	19.38 Yrs.	1.0418E+11	10.85	92.20	100.00
S5	17.59 Yrs.	1.0501E+11	10.80	92.57	100.00
R5	17.66 Yrs.	1.0537E+11	10.78	92.73	100.00
R4	17.94 Yrs.	1.0552E+11	10.78	92.79	100.00
S1.5	19.00 Yrs.	1.0717E+11	10.69	93.51	100.00
L5	17.78 Yrs.	1.0882E+11	10.61	94.23	100.00
L2	19.75 Yrs.	1.0900E+11	10.60	94.31	100.00
S4	17.84 Yrs.	1.1070E+11	10.52	95.04	100.00
S2	18.66 Yrs.	1.1114E+11	10.50	95.23	100.00
L4	18.12 Yrs.	1.1242E+11	10.44	95.78	100.00
S3	18.19 Yrs.	1.1304E+11	10.41	96.04	100.00
L3	18.81 Yrs.	1.1589E+11	10.28	97.24	100.00

Montana-Dakota Utilities Company

Gas Division

387.20 OTHER DISTRIBUTION EQUIP.

Simulated Plant Record Analysis Calculated As Of 12/31/2001

Simulated Balances Method

No. Of Test Points -	52
Interval Between Test Points -	1
First Test Point -	1950
Last Test Point -	2001

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	196.75 Yrs.	2.2855E+09	20.19	49.54	28.51
O3	142.25 Yrs.	2.3029E+09	20.11	49.73	28.75
SC	87.91 Yrs.	2.3417E+09	19.94	50.14	29.29
O1	87.91 Yrs.	2.3417E+09	19.94	50.14	29.29
O2	98.75 Yrs.	2.3422E+09	19.94	50.15	29.31
R0.5	73.75 Yrs.	2.4727E+09	19.41	51.53	31.10
S.5	71.34 Yrs.	2.6833E+09	18.63	53.68	33.57
R1	62.66 Yrs.	2.7548E+09	18.39	54.39	34.74
L0	78.89 Yrs.	2.7735E+09	18.33	54.57	34.76
L0.5	69.66 Yrs.	3.1472E+09	17.20	58.13	37.99
R1.5	56.12 Yrs.	3.1748E+09	17.13	58.38	39.54
S0	60.19 Yrs.	3.2815E+09	16.85	59.36	40.02
L1	62.44 Yrs.	3.7403E+09	15.78	63.37	42.16
S0.5	55.62 Yrs.	3.7608E+09	15.74	63.54	44.07
R2	51.41 Yrs.	3.8429E+09	15.57	64.23	46.16
L1.5	57.59 Yrs.	4.2485E+09	14.81	67.54	46.54
S1	52.06 Yrs.	4.4549E+09	14.46	69.16	49.02
R2.5	48.69 Yrs.	4.5291E+09	14.34	69.73	52.95
S1.5	49.94 Yrs.	5.0342E+09	13.60	73.52	53.28
L2	53.97 Yrs.	5.0946E+09	13.52	73.96	51.65
R3	46.69 Yrs.	5.4859E+09	13.03	76.75	60.86
S2	48.28 Yrs.	5.8400E+09	12.63	79.19	57.90
L3	49.41 Yrs.	6.5217E+09	11.95	83.68	61.11
S3	46.38 Yrs.	7.2192E+09	11.36	88.04	66.78
R4	45.12 Yrs.	7.2638E+09	11.32	88.31	74.35
L4	46.34 Yrs.	7.9155E+09	10.85	92.19	72.30
S4	45.12 Yrs.	8.8435E+09	10.26	97.44	78.69
L5	45.09 Yrs.	9.4118E+09	9.95	100.53	83.02
R5	44.53 Yrs.	9.4924E+09	9.91	100.96	89.14
S5	44.47 Yrs.	1.0183E+10	9.56	104.57	90.84
S6	44.12 Yrs.	1.1170E+10	9.13	109.51	98.74
SQ	43.00 Yrs.	1.2385E+10	8.67	115.32	100.00

Case No. PU-399-02-183
Depreciation Investigation
Exhibit_____(CWK-6)

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 375 - Structures & Improvements

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	3,425.08	435.45	12.71%	230.31	6.72%	205.14	5.99%
1969	4,310.44	819.74	19.02%	656.20	15.22%	163.54	3.79%
1970	4,433.29	1,076.90	24.29%	450.82	10.17%	626.08	14.12%
1971	2,081.69	883.96	42.46%	48.83	2.35%	835.13	40.12%
1972	2,058.30	-	0.00%	19.89	0.97%	(19.89)	-0.97%
1973	1,012.35	-	0.00%	59.26	5.85%	(59.26)	-5.85%
1974	3,269.04	2,424.62	74.17%	246.45	7.54%	2,178.17	66.63%
1975	1,584.93	98.73	6.23%	470.32	29.67%	(371.59)	-23.45%
1976	2,446.53	-	0.00%	166.82	6.82%	(166.82)	-6.82%
1977	661.00	-	0.00%	144.69	21.89%	(144.69)	-21.89%
1978	1,605.72	-	0.00%	875.01	54.49%	(875.01)	-54.49%
1979	303.10	-	0.00%	19.22	6.34%	(19.22)	-6.34%
1980	1,134.17	-	0.00%	627.51	55.33%	(627.51)	-55.33%
1981	1,442.23	-	0.00%	230.47	15.98%	(230.47)	-15.98%
1982	2,256.89	-	0.00%	609.90	27.02%	(609.90)	-27.02%
1983		-	0.00%		0.00%	-	0.00%
1984	628.89	-	0.00%		0.00%	-	0.00%
1985	2,049.04	1,096.13	53.49%	733.70	35.81%	362.43	17.69%
1986	1,006.41	(620.46)	-61.65%	781.10	77.61%	(1,401.56)	-139.26%
1987	891.58	-	0.00%	83.33	9.35%	(83.33)	-9.35%
1988	457.00	-	0.00%		0.00%	-	0.00%
1989	1,618.28	1.00	0.06%	448.28	27.70%	(447.28)	-27.64%
1990	773.00	-	0.00%	523.47	67.72%	(523.47)	-67.72%
1991	3,506.79	-	0.00%	2,521.31	71.90%	(2,521.31)	-71.90%
1992	3,956.71	-	0.00%	2,552.03	64.50%	(2,552.03)	-64.50%
1993	3,366.82	-	0.00%	1,633.72	48.52%	(1,633.72)	-48.52%
1994	5,438.75	-	0.00%	2,211.80	40.67%	(2,211.80)	-40.67%
1995	247.53	4,904.42	1981.34%	734.55	296.75%	4,169.87	1684.59%
1996	3,122.98	-	0.00%	4,739.85	151.77%	(4,739.85)	-151.77%
1997	5,835.64	850.00	14.57%	257.00	4.40%	593.00	10.16%
1998	150.63	-	0.00%	600.00	398.33%	(600.00)	-398.33%
1999	454.69	-	0.00%	4,286.94	942.83%	(4,286.94)	-942.83%
2000	3,897.84	1.00	0.03%	2,219.11	56.93%	(2,218.11)	-56.91%
2001	786.50	-	0.00%	2,596.09	330.08%	(2,596.09)	-330.08%

THREE - YEAR ROLLING BANDS

1968-1970	12,168.81	2,332.09	19.16%	1,337.33	10.99%	994.76	8.17%
1969-1971	10,825.42	2,780.60	25.69%	1,155.85	10.68%	1,624.75	15.01%
1970-1972	8,573.28	1,960.86	22.87%	519.54	6.06%	1,441.32	16.81%
1971-1973	5,152.34	883.96	17.16%	127.98	2.48%	755.98	14.67%
1972-1974	6,339.69	2,424.62	38.25%	325.60	5.14%	2,099.02	33.11%
1973-1975	5,866.32	2,523.35	43.01%	776.03	13.23%	1,747.32	29.79%
1974-1976	7,300.50	2,523.35	34.56%	883.59	12.10%	1,639.76	22.46%
1975-1977	4,692.46	98.73	2.10%	781.83	16.66%	(683.10)	-14.56%
1976-1978	4,713.25	-	0.00%	1,186.52	25.17%	(1,186.52)	-25.17%
1977-1979	2,569.82	-	0.00%	1,038.92	40.43%	(1,038.92)	-40.43%
1978-1980	3,042.99	-	0.00%	1,521.74	50.01%	(1,521.74)	-50.01%
1979-1981	2,879.50	-	0.00%	877.20	30.46%	(877.20)	-30.46%
1980-1982	4,833.29	-	0.00%	1,467.88	30.37%	(1,467.88)	-30.37%
1981-1983	3,699.12	-	0.00%	840.37	22.72%	(840.37)	-22.72%
1982-1984	2,885.78	-	0.00%	609.90	21.13%	(609.90)	-21.13%
1983-1985	2,677.93	1,096.13	40.93%	733.70	27.40%	362.43	13.53%
1984-1986	3,684.34	475.67	12.91%	1,514.80	41.11%	(1,039.13)	-28.20%
1985-1987	3,947.03	475.67	12.05%	1,598.13	40.49%	(1,122.46)	-28.44%
1986-1988	2,354.99	(620.46)	-26.35%	864.43	36.71%	(1,484.89)	-63.05%
1987-1989	2,966.86	1.00	0.03%	531.61	17.92%	(530.61)	-17.88%
1988-1990	2,848.28	1.00	0.04%	971.75	34.12%	(970.75)	-34.08%
1989-1991	5,898.07	1.00	0.02%	3,493.06	59.22%	(3,492.06)	-59.21%
1990-1992	8,236.50	-	0.00%	5,596.81	67.95%	(5,596.81)	-67.95%
1991-1993	10,830.32	-	0.00%	6,707.06	61.93%	(6,707.06)	-61.93%
1992-1994	12,762.28	-	0.00%	6,397.55	50.13%	(6,397.55)	-50.13%
1993-1995	9,053.10	4,904.42	54.17%	4,580.07	50.59%	324.35	3.58%
1994-1996	8,809.26	4,904.42	55.67%	7,686.20	87.25%	(2,781.78)	-31.58%
1995-1997	9,206.15	5,754.42	62.51%	5,731.40	62.26%	23.02	0.25%
1996-1998	9,109.25	850.00	9.33%	5,596.85	61.44%	(4,746.85)	-52.11%
1997-1999	6,440.96	850.00	13.20%	5,143.94	79.86%	(4,293.94)	-66.67%
1998-2000	4,503.16	1.00	0.02%	7,106.05	157.80%	(7,105.05)	-157.78%
1999-2001	5,139.03	1.00	0.02%	9,102.14	177.12%	(9,101.14)	-177.10%
1968-2001	70,213.84	11,971.49	17.05%	31,777.98	45.26%	(19,806.49)	-28.21%

Trend Analysis (End Year) 2001

*Based Upon 3-Year Rolling Averages

Annual Inflation	0.0275
ASL	50
Avg Ret Age	38
Years to ASL	12
Inflation Factor At 2.75% to	1.38

Gross Salv. Trend Analysis*		
1982-2001	**20-Year Trend**	**21.91%**
1987-2001	**15-Year Trend**	**27.19%**
1992-2001	**10-Year Trend**	**17.45%**
1997-2001	**5-Year Trend**	**-23.27%**

Adjusted Salvage & C/O/R	**-23.27%**	**62.67%**	**-85.94%**

1985 Total	14,456.58	6,271.22
LESS:		
Crookston	12,407.54	5,175.09
Net Activity	2,049.04	1,096.13

Case No. PU-399-02-183
Depreciation Investigation
Exhibit_____(CWK-6)

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 376 - Mains

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	200,220.26	16,598.28	8.29%	26,859.47	13.41%	(10,261.19)	-5.12%
1969	194,137.09	15,939.46	8.21%	43,168.49	22.24%	(27,229.03)	-14.03%
1970	267,046.03	23,230.21	8.70%	46,950.89	17.58%	(23,720.68)	-8.88%
1971	177,113.50	13,833.58	7.81%	56,809.25	32.08%	(42,975.67)	-24.26%
1972	157,195.80	13,435.85	8.55%	42,912.41	27.30%	(29,476.56)	-18.75%
1973	135,609.90	13,644.75	10.06%	27,848.00	20.54%	(14,203.25)	-10.47%
1974	79,682.47	4,158.86	5.22%	33,340.09	41.84%	(29,181.23)	-36.62%
1975	127,632.18	7,857.70	6.16%	43,072.35	33.75%	(35,214.65)	-27.59%
1976	195,879.62	9,760.39	4.98%	58,379.94	29.80%	(48,619.55)	-24.82%
1977	84,326.99	(3,773.39)	-4.47%	25,097.78	29.76%	(28,871.17)	-34.24%
1978	116,364.42	10,832.09	9.31%	46,758.20	40.18%	(35,926.11)	-30.87%
1979	123,150.94	11,190.96	9.09%	36,244.68	29.43%	(25,053.72)	-20.34%
1980	88,516.03	3,479.59	3.93%	38,660.28	43.68%	(35,180.69)	-39.74%
1981	152,498.86	6,295.38	4.13%	46,691.72	30.62%	(40,396.34)	-26.49%
1982	127,572.66	(2,610.34)	-2.05%	56,734.00	44.47%	(59,344.34)	-46.52%
1983	161,051.86	(581.14)	-0.36%	104,094.70	64.63%	(104,675.84)	-65.00%
1984	185,619.78	(504.59)	-0.27%	90,504.85	48.76%	(91,009.44)	-49.03%
1985	142,490.14	(6,867.12)	-4.82%	94,130.78	66.06%	(100,997.90)	-70.88%
1986	164,397.14	(401.47)	-0.24%	51,009.31	31.03%	(51,410.78)	-31.27%
1987	201,062.80	(231.86)	-0.12%	90,443.45	44.98%	(90,675.31)	-45.10%
1988	281,758.55	(4,416.44)	-1.57%	101,619.66	36.07%	(106,036.10)	-37.63%
1989	149,536.04	317.65	0.21%	69,598.16	46.54%	(69,280.51)	-46.33%
1990	92,157.64	(2,915.53)	-3.16%	35,838.46	38.89%	(38,753.99)	-42.05%
1991	208,283.95	3,390.22	1.63%	72,574.40	34.84%	(69,184.18)	-33.22%
1992	261,776.43	(2,741.03)	-1.05%	81,630.92	31.18%	(84,371.95)	-32.23%
1993	129,595.28	(3,971.17)	-3.06%	60,124.58	46.39%	(64,095.75)	-49.46%
1994	362,204.01	(340.60)	-0.09%	96,506.29	26.64%	(96,846.89)	-26.74%
1995	81,561.25	0.10	0.00%	22,341.68	27.39%	(22,341.58)	-27.39%
1996	312,810.33	767.42	0.25%	83,391.55	26.66%	(82,624.13)	-26.41%
1997	182,351.81	56,675.22	31.08%	-	0.00%	56,675.22	31.08%
1998	196,796.74	805.67	0.41%	76,362.06	38.80%	(75,556.39)	-38.39%
1999	186,253.29	-	0.00%	82,439.31	44.26%	(82,439.31)	-44.26%
2000	158,497.94	-	0.00%	61,044.27	38.51%	(61,044.27)	-38.51%
2001	171,123.71	-	0.00%	74,109.60	43.31%	(74,109.60)	-43.31%

THREE - YEAR ROLLING BANDS

1968-1970	661,403.38	55,767.95	8.43%	116,978.85	17.69%	(61,210.90)	-9.25%
1969-1971	638,296.62	53,003.25	8.30%	146,928.63	23.02%	(93,925.38)	-14.72%
1970-1972	601,355.33	50,499.64	8.40%	146,672.55	24.39%	(96,172.91)	-15.99%
1971-1973	469,919.20	40,914.18	8.71%	127,569.66	27.15%	(86,655.48)	-18.44%
1972-1974	372,488.17	31,239.46	8.39%	104,100.50	27.95%	(72,861.04)	-19.56%
1973-1975	342,924.55	25,661.31	7.48%	104,260.44	30.40%	(78,599.13)	-22.92%
1974-1976	403,194.27	21,776.95	5.40%	134,792.38	33.43%	(113,015.43)	-28.03%
1975-1977	407,838.79	13,844.70	3.39%	126,550.07	31.03%	(112,705.37)	-27.63%
1976-1978	396,571.03	16,819.09	4.24%	130,235.92	32.84%	(113,416.83)	-28.60%
1977-1979	323,842.35	18,249.66	5.64%	108,100.66	33.38%	(89,851.00)	-27.75%
1978-1980	328,031.39	25,502.64	7.77%	121,663.16	37.09%	(96,160.52)	-29.31%
1979-1981	364,165.83	20,965.93	5.76%	121,596.68	33.39%	(100,630.75)	-27.63%
1980-1982	368,587.55	7,164.63	1.94%	142,086.00	38.55%	(134,921.37)	-36.60%
1981-1983	441,123.38	3,103.90	0.70%	207,520.42	47.04%	(204,416.52)	-46.34%
1982-1984	474,244.30	(3,696.07)	-0.78%	251,333.55	53.00%	(255,029.62)	-53.78%
1983-1985	489,161.78	(7,952.85)	-1.63%	288,730.33	59.03%	(296,683.18)	-60.65%
1984-1986	492,507.06	(7,773.18)	-1.58%	235,644.94	47.85%	(243,418.12)	-49.42%
1985-1987	507,950.08	(7,500.45)	-1.48%	235,583.54	46.38%	(243,083.99)	-47.86%
1986-1988	647,218.49	(5,049.77)	-0.78%	243,072.42	37.56%	(248,122.19)	-38.34%
1987-1989	632,357.39	(4,330.65)	-0.68%	261,661.27	41.38%	(265,991.92)	-42.06%
1988-1990	523,452.23	(7,014.32)	-1.34%	207,056.28	39.56%	(214,070.60)	-40.90%
1989-1991	449,977.63	792.34	0.18%	178,011.02	39.56%	(177,218.68)	-39.38%
1990-1992	562,218.02	(2,266.34)	-0.40%	190,043.78	33.80%	(192,310.12)	-34.21%
1991-1993	599,655.66	(3,321.98)	-0.55%	214,329.90	35.74%	(217,651.88)	-36.30%
1992-1994	753,575.72	(7,052.80)	-0.94%	238,261.79	31.62%	(245,314.59)	-32.55%
1993-1995	573,360.54	(4,311.67)	-0.75%	178,972.55	31.21%	(183,284.22)	-31.97%
1994-1996	756,575.59	426.92	0.06%	202,239.52	26.73%	(201,812.60)	-26.67%
1995-1997	576,723.39	57,442.74	9.96%	105,733.23	18.33%	(48,290.49)	-8.37%
1996-1998	691,958.88	58,248.31	8.42%	159,753.61	23.09%	(101,505.30)	-14.67%
1997-1999	565,401.84	57,480.89	10.17%	158,801.37	28.09%	(101,320.48)	-17.92%
1998-2000	541,547.97	805.67	0.15%	219,845.64	40.60%	(219,039.97)	-40.45%
1999-2001	515,874.94	-	0.00%	217,593.18	42.18%	(217,593.18)	-42.18%
1968-2001	5,856,275.44	182,858.70	3.12%	1,977,291.58	33.76%	(1,794,432.88)	-30.64%

Trend Analysis (End Year) 2001

*Based Upon 3-Year Rolling Averages

Annual Inflation	0.0275
ASL	45
Avg Ret Age	25
Years to ASL	20
Inflation Factor At 2.75% t	1.72

Gross Salv. Trend Analysis*	
1982-2001 20-Year Trend	**4.11%**
1987-2001 15-Year Trend	**5.45%**
1992-2001 10-Year Trend	**5.99%**
1997-2001 5-Year Trend	**-2.72%**

Adjusted Salvage & C/O/R	**-2.72%**	**58.09%**	**-60.81%**

1985 Total	1003495.26	537399.44
LESS:		
Crookston	861005.12	544266.56
Net Activit	142490.14	-6867.12

Case No. PU-399-02-183
Depreciation Investigation
Exhibit_____(CWK-6)

Montana-Dakota Utilities Company
Gas Division

Analysis of Experienced Salvage
1968 through 2001

Account 380 - Services

Yea	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1968	58,055.53	3,059.40	5.27%	27,723.99	47.75%	(24,664.59)	-42.48%
1969	55,853.48	845.59	1.51%	26,200.12	46.91%	(25,354.53)	-45.39%
1970	78,879.56	530.18	0.67%	23,001.10	29.16%	(22,470.92)	-28.49%
1971	52,774.35	880.28	1.67%	35,729.03	67.70%	(34,848.75)	-66.03%
1972	79,522.93	697.12	0.88%	32,010.82	40.25%	(31,313.70)	-39.38%
1973	65,093.43	-	0.00%	48,919.91	75.15%	(48,919.91)	-75.15%
1974	64,653.14	596.73	0.92%	49,546.52	76.63%	(48,949.79)	-75.71%
1975	37,754.54	2,843.03	7.53%	50,159.99	132.86%	(47,316.96)	-125.33%
1976	68,213.75	-	0.00%	67,351.08	98.74%	(67,351.08)	-98.74%
1977	192,462.86	-	0.00%	53,563.74	27.83%	(53,563.74)	-27.83%
1978	(92,938.46)	-	0.00%	41,768.32	-44.94%	(41,768.32)	44.94%
1979	55,534.41	-	0.00%	79,598.42	143.33%	(79,598.42)	-143.33%
1980	61,494.60	-	0.00%	99,855.84	162.38%	(99,855.84)	-162.38%
1981	63,423.25	-	0.00%	102,204.63	161.15%	(102,204.63)	-161.15%
1982	84,858.56	-	0.00%	145,791.60	171.81%	(145,791.60)	-171.81%
1983	73,868.72	-	0.00%	134,537.21	182.13%	(134,537.21)	-182.13%
1984	95,311.04	-	0.00%	162,402.35	170.39%	(162,402.35)	-170.39%
1985	96,419.65	-	0.00%	218,282.65	226.39%	(218,282.65)	-226.39%
1986	82,204.03	-	0.00%	164,534.27	200.15%	(164,534.27)	-200.15%
1987	102,945.66	-	0.00%	178,763.94	173.65%	(178,763.94)	-173.65%
1988	130,255.01	-	0.00%	210,138.61	161.33%	(210,138.61)	-161.33%
1989	103,193.55	-	0.00%	194,613.23	188.59%	(194,613.23)	-188.59%
1990	87,093.75	-	0.00%	156,894.03	180.14%	(156,894.03)	-180.14%
1991	112,288.21	-	0.00%	154,878.88	137.93%	(154,878.88)	-137.93%
1992	152,087.98	-	0.00%	198,004.44	130.19%	(198,004.44)	-130.19%
1993	117,390.79	-	0.00%	156,754.23	133.53%	(156,754.23)	-133.53%
1994	213,594.75	-	0.00%	225,751.58	105.69%	(225,751.58)	-105.69%
1995	85,394.58	238.78	0.28%	132,997.10	155.74%	(132,758.32)	-155.46%
1996	190,887.20	489.25	0.26%	196,474.55	102.93%	(195,985.30)	-102.67%
1997	147,018.12	274.30	0.19%	167,867.03	114.18%	(167,592.73)	-113.99%
1998	156,868.35	165.57	0.11%	232,839.48	148.43%	(232,673.91)	-148.32%
1999	129,801.17	-	0.00%	205,972.55	158.68%	(205,972.55)	-158.68%
2000	134,394.03	-	0.00%	200,260.66	149.01%	(200,260.66)	-149.01%
2001	123,831.18	31.47	0.03%	203,228.57	164.12%	(203,197.10)	-164.09%

THREE - YEAR ROLLING BANDS

1968	192,788.57	4,435.17	2.30%	76,925.21	39.90%	(72,490.04)	-37.60%
1969	187,507.39	2,256.05	1.20%	84,930.25	45.29%	(82,674.20)	-44.09%
1970	211,176.84	2,107.58	1.00%	90,740.95	42.97%	(88,633.37)	-41.97%
1971	197,390.71	1,577.40	0.80%	116,659.76	59.10%	(115,082.36)	-58.30%
1972	209,269.50	1,293.85	0.62%	130,477.25	62.35%	(129,183.40)	-61.73%
1973	167,501.11	3,439.76	2.05%	148,626.42	88.73%	(145,186.66)	-86.68%
1974	170,621.43	3,439.76	2.02%	167,057.59	97.91%	(163,617.83)	-95.90%
1975	298,431.15	2,843.03	0.95%	171,074.81	57.32%	(168,231.78)	-56.37%
1976	167,738.15	-	0.00%	162,683.14	96.99%	(162,683.14)	-96.99%
1977	155,058.81	-	0.00%	174,930.48	112.82%	(174,930.48)	-112.82%
1978	24,090.55	-	0.00%	221,222.58	918.30%	(221,222.58)	-918.30%
1979	180,452.26	-	0.00%	281,658.89	156.08%	(281,658.89)	-156.08%
1980	209,776.41	-	0.00%	347,852.07	165.82%	(347,852.07)	-165.82%
1981	222,150.53	-	0.00%	382,533.44	172.20%	(382,533.44)	-172.20%
1982	254,038.32	-	0.00%	442,731.16	174.28%	(442,731.16)	-174.28%
1983	265,599.41	-	0.00%	515,222.21	193.98%	(515,222.21)	-193.98%
1984	273,934.72	-	0.00%	545,219.27	199.03%	(545,219.27)	-199.03%
1985	281,569.34	-	0.00%	561,580.86	199.45%	(561,580.86)	-199.45%
1986	315,404.70	-	0.00%	553,436.82	175.47%	(553,436.82)	-175.47%
1987	336,394.22	-	0.00%	583,515.78	173.46%	(583,515.78)	-173.46%
1988	320,542.31	-	0.00%	561,645.87	175.22%	(561,645.87)	-175.22%
1989	302,575.51	-	0.00%	506,386.14	167.36%	(506,386.14)	-167.36%
1990	351,469.94	-	0.00%	509,777.35	145.04%	(509,777.35)	-145.04%
1991	381,766.98	-	0.00%	509,637.55	133.49%	(509,637.55)	-133.49%
1992	483,073.52	-	0.00%	580,510.25	120.17%	(580,510.25)	-120.17%
1993	416,380.12	238.78	0.06%	515,502.91	123.81%	(515,264.13)	-123.75%
1994	489,876.53	728.03	0.15%	555,223.23	113.34%	(554,495.20)	-113.19%
1995	423,299.90	1,002.33	0.24%	497,338.68	117.49%	(496,336.35)	-117.25%
1996	494,773.67	929.12	0.19%	597,181.06	120.70%	(596,251.94)	-120.51%
1997	433,687.64	439.87	0.10%	606,679.06	139.89%	(606,239.19)	-139.79%
1998	421,063.55	165.57	0.04%	639,072.69	151.78%	(638,907.12)	-151.74%
1999	388,026.38	31.47	0.01%	609,461.78	157.07%	(609,430.31)	-157.06%
1968	3,260,483.70	10651.7	0.33%	4,378,620.47	134.29%	(4,367,968.77)	-133.97%

Trend Analysis (End Y 2001

*Based Upon 3-Year Rolling Averages

Annual Inflation	0.0275
ASL	40
Avg Ret Age	20
Years to ASL	20
Inflation Factor At 2.75	1.720428431

Gross Salv. Trend Analysis*

1982-2001	**20-Year Trend**	**0.11%**
1987-2001	**15-Year Trend**	**0.13%**
1992-2001	**10-Year Trend**	**0.12%**
1997-2001	**5-Year Trend**	**-0.07%**

Adjusted Salvage & C/O/R	**-0.07%**	**231.04%**	**-231.11%**

Charles W. King

Docket No. PU-399-02-183
Exhibit_____(CWK-7)

Summary of Statement No. 143
Financial Accounting Standards Board

Summary of Statement No. 143

Accounting for Asset Retirement Obligations (Issued 6/01)

Summary

This Statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This Statement applies to all entities. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees. As used in this Statement, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. This Statement amends FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.*

Reasons for Issuing This Statement

The Board decided to address the accounting and reporting for asset retirement obligations because:

- Users of financial statements indicated that the diverse accounting practices that have developed for obligations associated with the retirement of tangible long-lived assets make it difficult to compare the financial position and results of operations of companies that have similar obligations but account for them differently.

- Obligations that meet the definition of a liability

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were not being recognized when those liabilities were incurred or the recognized liability was not consistently measured or presented.

Differences between This Statement, Statement 19, and Existing Practice

This Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This Statement differs from Statement 19 and current practice in several significant respects.

- Under Statement 19 and most current practice, an amount for an asset retirement obligation was recognized using a cost-accumulation measurement approach. Under this Statement, the amount initially recognized is measured at fair value.

- Under Statement 19 and most current practice, amounts for retirement obligations were not discounted and therefore no accretion expense was recorded in subsequent periods. Under this Statement, the liability is discounted and accretion expense is recognized using the credit-adjusted risk-free interest rate in effect when the liability was initially recognized.

- Under Statement 19, dismantlement and restoration costs were taken into account in determining amortization and depreciation rates. Consequently, many entities recognized asset retirement obligations as a contra-asset. Under this Statement, those obligations are recognized as a liability. Also, under Statement 19 the obligation was recognized over the useful life of the related asset. Under this Statement, the obligation is recognized when the liability is incurred.

Some current practice views a retirement obligation as a contingent liability and applies FASB Statement No. 5, *Accounting for Contingencies,* in determining when to recognize a liability. The measurement objective in this Statement is fair value, which is not compatible with a Statement 5 approach. A fair value measurement accommodates uncertainty in the amount and timing of settlement of the liability, whereas under Statement 5 the

recognition decision is based on the level of uncertainty.

This Statement contains disclosure requirements that provide descriptions of asset retirement obligations and reconciliations of changes in the components of those obligations.

How the Changes in This Statement Improve Financial Reporting

Because all asset retirement obligations that fall within the scope of this Statement and their related asset retirement cost will be accounted for consistently, financial statements of different entities will be more comparable. Also,

- Retirement obligations will be recognized when they are incurred and displayed as liabilities. Thus, more information about future cash outflows, leverage, and liquidity will be provided. Also, an initial measurement at fair value will provide relevant information about the liability.

- Because the asset retirement cost is capitalized as part of the asset's carrying amount and subsequently allocated to expense over the asset's useful life, information about the gross investment in long-lived assets will be provided.

- Disclosure requirements contained in this Statement will provide more information about asset retirement obligations.

How the Statement Generally Changes Financial Statements

Because of diverse practice in current accounting for asset retirement obligations, various industries and entities will be affected differently. This Statement will likely have the following effects on current accounting practice:

- Total liabilities generally will increase because more retirement obligations will be recognized. For some entities, obligations will be recognized earlier, and they will be displayed as liabilities rather than as contra-assets. In certain cases, the amount of a recognized liability may be lower than that recognized in current practice because a fair value measurement entails discounting.

- The recognized cost of assets will increase because asset retirement costs will be added to the carrying amount of the long-lived asset. Assets also will increase because assets acquired with an existing retirement obligation will be displayed on a gross rather than on a net basis.

- The amount of expense (accretion expense plus depreciation expense) will be higher in the later years of an asset's life than in earlier years.

How the Conclusions in the Statement Relate to the Conceptual Framework

The Board concluded that all retirement obligations within the scope of this Statement that meet the definition of a liability in FASB Concepts Statement No. 6, *Elements of Financial Statements,* should be recognized as a liability when the recognition criteria in FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises,* are met.

The Board also decided that the liability for an asset retirement obligation should be initially recognized at its estimated fair value as discussed in FASB Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements.*

Effective Date

This Statement is effective for financial statements issued for fiscal years beginning after June 15, 2002. Earlier application is encouraged.

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Case No. PU-399-02-183
Exhibit_____CWK-8)

Montana-Dakota Utilities Co.
Net Salvage Ratios

Account No.	Account Title	AUS Consultants	Conventional Net Salvage	SFAS 143 Method	Staff Recommended
Distribution Plant					
375.00	Distr. Meas & Reg. Station Structures	-50%	-30%	-19%	-19%
376.00	Distribution Mains	-60%	-30%	-10%	-10%
378.00	Meas. & Reg Station Eqpt - General	-30%	-35%	-12%	-12%
379.00	Meas. & Reg Station Eqpt - City Gate	-15%	15%		15%
380.00	Services	-175%	-135%	-37%	-37%
383.00	Service Regulators	10%	15%		15%
385.00	Industrial Meas. & Reg Station Eqpt.	-15%	0%		0%
General Plant					
390.00	General Structures	-10%	0%		0%
391.10	Office Furniture & Equipment	5%	5%		5%
392.00	Transportation Equipment	15%	15%		15%
394.1,2	Tools, Shop and Garage Equipment	10%	10%		10%
394.40	Vehicle Refueling Equipment	0%	20%		20%
296.12	Work Equipment	35%	25%		25%
296.20	Power Operated Equipment	60%	75%		60%
Common Plant					
290.00	General Structures	-10%	0%		0%
391.10	Office Furniture & Equipment	5%	5%		5%
392.10	Transportation Equipment (Trailers)	15%	15%		15%
392.20	Transportation Eqpt (Cars & Trucks)	20%	20%		20%
396.20	Power Operated Equipment	40%	50%		45%
397.10	Radio Communications Equipment	-10%	0%		0%
397.30	General Telephone Communications	10%	5%		5%
398.00	Miscellaneous Equipment	5%	5%		5%

Year	BOY	EOY	Mid Year
a	b=b(a-1)/1.07	c=1/(1.07 ^ a)	d=(b+c)/2
1	1.000000000	0.934579439	0.967289720
2	0.934579439	0.873438728	0.904009084
3	0.873438728	0.816297877	0.844868303
4	0.816297877	0.762895212	0.789596544
5	0.762895212	0.712986179	0.737940696
6	0.712986179	0.666342224	0.689664202
7	0.666342224	0.622749742	0.644545983
8	0.622749742	0.582009105	0.602379423
9	0.582009105	0.543933743	0.562971424
10	0.543933743	0.508349292	0.526141517
11	0.508349292	0.475092796	0.491721044
12	0.475092796	0.444011959	0.459552378
13	0.444011959	0.414964448	0.429488204
14	0.414964448	0.387817241	0.401390844
15	0.387817241	0.362446020	0.375131630
16	0.362446020	0.338734598	0.350590309
17	0.338734598	0.316574390	0.327654494
18	0.316574390	0.295863916	0.306219153
19	0.295863916	0.276508333	0.286186125
20	0.276508333	0.258419003	0.267463668
21	0.258419003	0.241513087	0.249966045
22	0.241513087	0.225713165	0.233613126
23	0.225713165	0.210946883	0.218330024
24	0.210946883	0.197146620	0.204046752
25	0.197146620	0.184249178	0.190697899
26	0.184249178	0.172195493	0.178222335
27	0.172195493	0.160930367	0.166562930
28	0.160930367	0.150402212	0.155666290
29	0.150402212	0.140562815	0.145482514
30	0.140562815	0.131367117	0.135964966
31	0.131367117	0.122773007	0.127070062
32	0.122773007	0.114741128	0.118757067
33	0.114741128	0.107234699	0.110987913
34	0.107234699	0.100219345	0.103727022
35	0.100219345	0.093662939	0.096941142
36	0.093662939	0.087535457	0.090599198
37	0.087535457	0.081808838	0.084672148
38	0.081808838	0.076456858	0.079132848
39	0.076456858	0.071455008	0.073955933
40	0.071455008	0.066780381	0.069117694
41	0.066780381	0.062411571	0.064595976
42	0.062411571	0.058328571	0.060370071
43	0.058328571	0.054512683	0.056420627
44	0.054512683	0.050946433	0.052729558
45	0.050946433	0.047613489	0.049279961
46	0.047613489	0.044498588	0.046056038
47	0.044498588	0.041587465	0.043043026
48	0.041587465	0.038866790	0.040227127
49	0.038866790	0.036324103	0.037595446
50	0.036324103	0.033947759	0.035135931

Montana-Dakota Utilities
Negative Salvage Ratios - SFAS 143 Method

		Source	A/C 375 Structures	A/C 376 Mains	A/C 378 Reg&Meas Eqpt.-Gen	A/C 380 Services
1	Conventional Negative Salvage Ratios	CWK-8	-30%	-30%	-35%	-135%
2	Remaining Life	CWK-1, Schedule 1	32	43	38	43
3	Discount @ 7.0%	Page 1	0.13596	0.05642	0.07913	0.05642
4	Dicounted Negative Salvage Ratios	Line 1 x Line 3	-4.08%	-1.69%	-2.77%	-7.62%
5	Current Year's PV Increment Percent	Page 1, ((L2-1)-L2)) x Line 1	-0.25%	-0.15%	-0.19%	-0.53%
6	Service Life	CWK-1, Schedule 2, Col (I)	60	58	50	55
7	PV x Service Life	Line 6 x Line 7	-14.96%	-8.42%	-9.69%	-29.32%
8	Net Salvage Ratio	Line 4 + Line 13	-19%	-10%	-12%	-37%

#DIV/0!

PU-399-02-183

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1. Article Addressed to:
Don Ball
MDU
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☑ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 8/15/03

D. Is delivery address different from item 1? ☐ Yes
if YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7002 2410 0003 4912 3488

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1. Article Addressed to:
Douglas Schulz
MDU
400 N 4th St
Bismarck ND 58501

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X [signature] ☑ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 8/15/03

D. Is delivery address different from item 1? ☐ Yes
if YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7002 2410 0003 4912 3464

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1. Article Addressed to:
Dan Kunitz
PO Box 1695
Bismarck ND 58502-1695

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A. Signature
X [signature] ☑ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 8/15/03

D. Is delivery address different from item 1? ☐ Yes
if YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7002 2410 0003 4912 3471

PU-399-02-183

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1. Article Addressed to:

William Pearce
PO Box 400
Bismarck ND 58502-0400

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) Roger Lewis | C. Date of Delivery 4-25-03

D. Is delivery address different from item 1? ☐ Yes
if YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 1940 0005 3425 8643

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1. Article Addressed to:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [illegible] | C. Date of Delivery 4-25-03

D. Is delivery address different from item 1? ☐ Yes
if YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 1940 0005 3425 8650

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PU-399-02-183

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- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Douglas W Schultz
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [illegible] | C. Date of Delivery 4-25-03

D. Is delivery address different from item 1? ☐ Yes
if YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

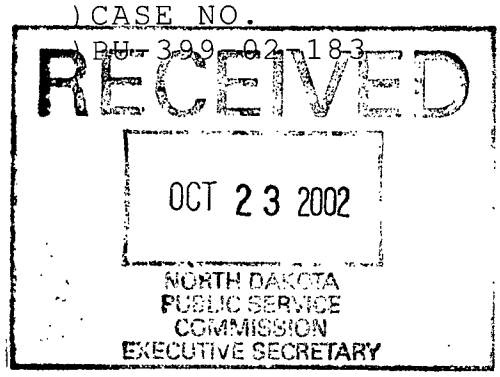
4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 1940 0005 3425 8636

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
Montana-Dakota Utilities Co. Natural Gas Rate Increase Application	)	CASE NO. PU-399-02-183



TRANSCRIPT OF HEARING

State Capitol
Commission Hearing Room
Bismarck, North Dakota
October 7, 2002

Before Allen C. Hoberg
Hearing Officer

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A P P E A R A N C E S

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Bismarck, North Dakota 58505-0480

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FOR MONTANA-DAKOTA
UTILITIES CO.

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EXHIBITS

No.	Marked	Offered	Received	Description
1-3	22	177	177	Application
2-2	22	177	177	Statements A - O
3	22	35	35	Direct testimony of C. Wayne Fox
4	22	60	60	Direct testimony of J. Stephen Gaske
5	22	124	124	Direct testimony of Craig A. Keller
6	22	132	132	Direct testimony of Rita A. Mulkern

EXHIBITS

No.	Marked	Offered	Received	Description
7	22	146	146	Direct testimony of Richard A. Espeland
8	22	159	160	Direct testimony of Russell A. Feingold
9	22	174	174	Direct testimony of Tamie A. Aberle
10	36	37	37	Memo regarding 2001 annual reports
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EXHIBITS

No.	Marked	Offered	Received	Description
20	219	221	221	Direct testimony of Michael J. Majoros, Jr., page 6 table expanded
21	315			MDU response to data request 21
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EXHIBITS

No.	Marked	Offered	Received	Description
33	415	445	445	Summary of DCF studies
34	415	452	452	Ibbotson historical returns
35	415	447	447	Article regarding WGL Holdings
36	415	450	452	Bond yields of Mr. King's proxy group and MDU Resources/Montana-Dakota Bonds
37	489	497	497	MDU gas utility - ND, rate 60 bill comparison, residential gas service

(The following proceedings were had and made of record, Monday, October 7, 2002, commencing at 9:00 a.m.)

MR. HOBERG: Let's begin. Let the record show it's approximately 9:00 a.m. on October 7, 2002. This is the time and place scheduled in the Public Service Commission hearing room in the State capital in Bismarck, North Dakota, for the hearing in the matter of the application of Montana-Dakota Utilities for a natural gas rate increase.

In June of this year the Office of Administrative Hearings received a request from the Public Service Commission to provide an administrative law judge to preside in this matter. My name is Allen Hoberg, and I've been duly designated as the procedural hearing officer to preside today.

Let's start with the appearances of the parties for the record in this matter, beginning with the applicant, followed by the Commission staff. Will counsel please state their appearances? Mr. Pearce, please.

MR. PEARCE: Yes. Thank you. William P. Pearce of Pearce and Durick, in Bismarck, appearing on behalf of the applicant, Montana-Dakota Utilities

Company.

MR. HOBERG: And who do you have with you?

MR. PEARCE: With me to my left is Mr. Don Ball, manager of regulatory affairs for the company, and to his left is Mr. Douglas Schulz, who is an attorney with the company, also appearing for the company.

MR. HOBERG: Thank you. You have a number of witnesses today.

MR. PEARCE: Yes. We have nine witnesses altogether.

MR. HOBERG: Thank you, Mr. Pearce. Mr. Binek, please.

MR. BINEK: My name is William Binek. I'm counsel for the Public Service Commission. I'm representing the Commission advocacy staff in this proceeding. Seated to my right is Mr. Charles King, a Commission consultant, and to the right of Mr. King is Michael Majoros, another consultant. And at the end of the table is Patrick Fahn, a public utility analyst with the Public Service Commission.

MR. HOBERG: Thank you, Mr. Binek. Is there anyone else present today who may wish to give testimony, either for or against the application?

Anyone else present? No one else present.

Then, of course, to my left we have members of the Public Service Commission. To my immediate left, Commissioner Leo Reinbold, and then Commission President, Susan Wefald, and Commissioner Tony Clark.

And starting with Commissioner Reinbold, who has the natural gas portfolio, I'll ask for your opening comments, please.

COMMISSIONER REINBOLD: Thank you. Good morning, and welcome. It's good to see so much interest. It's an interesting case. We're here to determine what needs to be allowed and also what must be disallowed. That's our job. We're here to do that by being fair to all parties concerned and get done by Noon because everyone has a plane to catch. Welcome.

COMMISSIONER WEFALD: On Wednesday?

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

COMMISSIONER WEFALD: Good morning. We know that this case is very important, both to the company and to the consumers of North Dakota, and we're looking forward to getting a good record. Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

COMMISSIONER CLARK: Good morning. I look forward to hearing the testimony. Thank you.

MR. HOBERG: Thank you. Just for the record, our court reporter is Linda Gingery today.

Just a very brief summary of the application. It's set out very well in the notice of hearing. On April 12th of this year MDU filed an application to increase its rates for natural gas service by an amount sufficient to provide increased total annual revenue of $2,844,132. And then the rest of the proposals are adequately set forth in the notice of hearing, and I won't go through the rest of those today.

But on June 5th of this year, the Public Service Commission issued a notice of hearing, notice of public input sessions and notice of intervention deadline. And the notice of hearing scheduled a hearing for today and, of course, that's why we're here.

It's my understanding there have been no petitions to intervene in this matter filed with the Commission. However, there were public input sessions held via interactive television on July

15th of this year at Noon, Central Daylight Time, and giving members of the public an opportunity to express their concerns. And those sessions were held at Bismarck State College, Dickinson State University, Minot State University, Lake Region State College, North Dakota State Hospital, and Williston State College.

The issues, according to the notice of hearing, to be considered in this matter include:

Number 1: What is the value of MDU's property, used and useful, for the service and convenience of the public of North Dakota?

Number 2: What is MDU's rate of return on this property, used and useful, for the service and convenience of the public of North Dakota?

Number 3: What is the just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

Number 4: What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public of North Dakota?

Number 5: Are MDU's rate schedules

designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

Number 6: Any other relevant information or proposals concerning the proceeding.

The hearing procedure today will be as follows: I'll first call on the applicant to present its case for the granting of the application. And Mr. Pearce has stated that he has nine witnesses on behalf of the company today. Each witness called by the applicant will be subject to cross-examination by Commission staff and by the Commission. And following the direct examination then by Mr. Pearce, cross-examination by Commission staff and questions by the Commission, I'll allow such further questions of the witnesses as are necessary.

Upon completion of the applicant's case, I'll call on the Commission staff to present its case. And Mr. Binek has informed us that he has two witnesses. It will be the same procedure there; direct examination by Mr. Binek, cross-examination by Mr. Pearce, questions by the Commission staff, and then such further questions of the witnesses as are necessary.

I think probably most of the evidence that's being offered today has already been docketed. Probably some additional evidence, too. And that will be offered also, though, and the docket number indicated when it's offered. And we'll mark the exhibits consecutively, 1 through whatever, and also indicate the docket number for those that have already been docketed. If there are additional exhibits being offered, we need seven copies for the record today.

No decision will be reached on this matter today. The proceedings are being transcribed and tape-recorded and will be reviewed by the Commission later. And, thereafter, the Commission will issue findings of fact and conclusions of law and an order as to whether the application should be issued, denied, or as to other appropriate administrative action.

If the party doesn't agree with the final decision of the Public Service Commission, they may have appeal rights or other rights under North Dakota Century Code Chapter 28-32, which is known as The Administrative Agencies Practices Act, or under the Rules of Commission, North Dakota Administrative Code, Article 69-02.

The issues today are as I previously stated. The burden of proof is on the applicant to show by the preponderance of the evidence, also known as the greater weight of the evidence, that it is entitled to a grant of the application it seeks.

Any questions about the procedures today? Mr. Pearce?

MR. PEARCE: No, sir. Except to point out that we will have our rebuttal case basically to put on after the staff's case.

MR. HOBERG: Correct. Thank you. Yes, there will be a rebuttal case presented. Mr. Binek?

MR. BINEK: Nothing.

MR. HOBERG: Just one other housekeeping item. There was a trade secret protection application filed in this matter and an order issued, so I would appreciate it if counsel would keep me apprised of when something that needs trade secret protection is going to be dealt with and we can deal with it appropriately. All right.

Mr. Pearce, do you have an opening statement to make?

MR. PEARCE: Yes, I do. I've got a brief opening statement I'd like to read.

MR. HOBERG: Please proceed.

MR. PEARCE: This case is an application by Montana-Dakota Utilities Company seeking the Commission's approval of an increase in its residential and firm general service gas rates that would generate an additional $2,844,132 in operating revenues, which is about a 4.1 percent overall increase. This increase is required to enable the company to continue to provide safe and reliable service to its approximately 83,500 customers in the state.

As the company's testimony in the case will show, the need for the increased revenue is driven by the necessity of meeting increases in the operating expenses of its gas distribution facilities in North Dakota. The company also needs an adequate permitted rate of return on the company's property devoted to gas distribution operations for it to be able to attract sufficient capital and maintain the quality, reliability and safety of its gas distribution services.

The last general rate increase was authorized by the Commission in November 1994, and it was a decrease in the gas rates as a result of a settlement that took effect in January 1999. This proceeding, of course, does not address the cost of

gas itself which the company acquires for distribution in its system. That's simply a pass-through component of the rates handled by the automatic adjustment procedures.

The list of company witnesses and the areas covered by their testimony will be summarized in the opening testimony of Mr. Wayne Fox, the company president.

One of the major components in the operating expense of the company is the depreciation expense allowance and that is a major factor in this case. The staff has done a curious thing not seen in the normal rate case proceeding. They have taken the depreciation study used in current rates and critiqued a very small portion of it, with the outcome being lower depreciation charges. This is not appropriate to base depreciation on a piecemeal critique of that study. We feel -- the company's position, as will be described by its witnesses, is it's premature at this point to make adjustments to the present depreciation rates which are based on a thorough depreciation study done by Stone & Webster in 1991. And they have been previously recognized by the Commission and applied in the previous rate case. The staff has not prepared a proper

depreciation study and no adjustment of the depreciation rates should be entertained by the Commission in this proceeding.

In addition, the question of the applicability of what's called FAS 143; that is, Financial Accounting Standard 143, will arise in the testimony that's already been filed in this case. This is a new financial accounting standard applicable to North Dakota's public utilities at the end of the year. FAS 143 will require companies to charge -- sorry -- to change the method of accounting for the expected retirement costs of an asset over the asset's useful life. FAS 143 is a very new and untested procedure at this point and the industry is currently engaged in a great deal of analysis and debate as to how and in what manner it should be implemented.

The implementation of 143 in North Dakota is not a matter which should be or reasonably can be addressed as an ancillary matter in a rate case involving a single utility company like Montana-Dakota operating in North Dakota. FAS 143 is a much broader matter than the specific issues in a single company rate case and many decisions need to be made before it can be effectively implemented.

We feel this complex question can only be properly addressed in a generic rulemaking proceeding by this Commission, in which all the utilities operating in North Dakota may participate and present their views on the question. For this reason, our position is that the Commission should not address FAS 143 in this case, but should defer that issue to its proper place in a separate rulemaking proceeding that would involve all the other utilities in which questions relative to the implementation can be addressed in an appropriate setting.

With that background, MDU makes -- moves the Commission to defer any action on FAS 143 in this proceeding and set the matter, that accounting standard for a generic rulemaking proceeding at some appropriate point in the future.

With regard to the design of the proposed rates, the company has proposed changes to accomplish the objectives of providing a measure of stability during periods of admirable weather; being user-understandable for consumers, being simple to administer, and providing for enhanced fixed cost recovery.

We have also included an alternative proposal in the event the Commission finds the

primary proposal unacceptable. The company urges the Commission to accept the primary proposal as it provides the best fit with the objectives. However, should the Commission not adopt the primary proposal, the company urges the Commission to adopt the alternative proposal that will be discussed in the testimony.

MR. HOBERG: Thank you, Mr. Pearce.

Mr. Binek, do you have any opening to make, perhaps in response to the motion to defer in regard to FAS 143?

MR. BINEK: I'd like to make a couple comments.

First of all, I think it's appropriate to consider FAS 143 and its implications to MDU. Secondly, with regard to depreciation, depreciation is a major issue in this case. MDU would like to have the Commission defer any consideration on depreciation until it completes a depreciation study that I understand is presently in progress. The staff's position on that has been and continues to be that if a part of the case, and a very important part of the case, is not -- or should not be considered at this point, none of the case should be considered at this point.

There are other important issues in this case as well, such as the rate of return that the company should be allowed. We are far apart in our recommendations on that. The company is asking the Commission to allow a return on equity that is in excess of anything that we have seen, either in North Dakota or around the country for that matter. On the other hand, the recommendations of the Commission's consultants are in line with what is occurring not only in North Dakota, but across the country as well.

MDU's application is a bit curious because MDU's gas earnings have been very stable and are very reasonable at the present time. And it doesn't appear that MDU is in any need of any increase, but that will be determined by the Commission in this proceeding.

I think that's all I have.

MR. HOBERG: Thank you, Mr. Binek.

Mr. Pearce, I understand your motion to defer is a formal motion?

MR. PEARCE: Yes.

MR. HOBERG: And I would advise the Commission to take that under advisement and I don't know if a ruling on that is necessary right now, but

something to take under advisement as part of this proceeding. You don't expect a ruling?

MR. PEARCE: No, that's what we anticipated.

MR. HOBERG: All right. Thank you both.

Would you like to call your first witness, please, Mr. Pearce?

MR. PEARCE: Thank you. I think I'm going to ask, just for convenience, the application and supporting statements are already filed, but in case they need to be referred to, I'd like to mark those as Exhibits 1 and 2, the two books.

MR. BINEK: Your Honor, the direct testimony is not shown as separate docket entries so perhaps they be should be identified separately as exhibits.

MR. HOBERG: That's what we're going to do, but the application, I believe, is marked as Exhibit 1-Docket 3.

MR. PEARCE: Right.

MR. HOBERG: And what was the other document?

MR. PEARCE: Statements A through O. And that's going to be Exhibit 2 and it's also Docket 2.

MR. HOBERG: Is that all the direct?

MR. PEARCE: That's simply the application and statements. The direct will be, I believe, Exhibits 3, 4, 5, 6, 7, 8, 9, and 10. And it's the seven direct -- prefiled direct testimony. It's all in one, single book there, but I think that will have the next seven exhibit numbers.

MR. HOBERG: Let's go off the record.

(Exhibits 1, 2, 3, 4, 5, 6, 7, 8, and 9 were marked for identification.)

(Discussion off the record.)

MR. HOBERG: Okay. The packet that we have of all of the direct testimony of Montana-Dakota Utilities is marked on the outside as Docket No. 1, and the inside of each of the -- direct testimony of each of the witnesses will be marked consecutively as 3 through 9, and that's how we'll be referring to them during the presentations then.

Mr. Fox is the first witness?

MR. PEARCE: Yes, he is.

MR. HOBERG: Mr. Fox, please.

Please be seated. As you know, I'm required by law to tell all the witnesses at administrative proceedings that the maximum penalty for perjury in this state is a Class C felony, punishable by a maximum five years imprisonment,

$5,000 fine, or both.

Mr. Fox, being advised of the penalty for perjury, do you promise to tell the truth in this matter? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce, please.

C. WAYNE FOX,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Would you please state your name and your business address?

A. My name is C. Wayne Fox. My business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Company?

A. I am president of Montana-Dakota Utilities, a division of MDU Resources Group, Incorporated.

Q. What are your duties and responsibilities with Montana-Dakota?

A. I have executive responsibility for the development, coordination and implementation of the

strategies and policies relative to all areas of operation.

Q. Would you please outline your educational and professional background?

A. In 1964 I received a Bachelor of Science degree in electrical engineering from Chicago Technical College, Chicago, Illinois. I received a Master of Arts degree in business administration from the University of Illinois, Springfield, Illinois in 1975. Upon graduating from college in 1974, I joined the Illinois Commerce Commission, the state body regulating public utilities in Illinois, as an electrical engineer.

Upon termination of my employment with the Illinois Commerce Commission in June 1980, I was serving as manager of the public utilities division. In that capacity my duties included testifying in formal cases before the Commission, formulating and coordinating Commission policies on technical and administrative matters, processing formal and informal cases, and advising the Commission on matters related to the regulation of public utilities operating in the State of Illinois.

In June 1980 I joined Montana-Dakota as assistant treasurer, regulatory affairs, retaining

that position until May 1982 when I was elected assistant vice-president, regulatory affairs. In May 1985 I was promoted to vice-president, regulatory affairs. In May 1987 my duties were broadened to include the company's purchasing and general services activities. At that time my title was changed to vice-president, regulatory affairs and general services. I assumed my present position in August 2000.

I also have been involved with the activities of the Electric Power Research Institute, the Edison Electric Institute, and the American Gas Association.

Q. Have you testified before this Commission and other state regulatory bodies?

A. Yes. I have previously sponsored testimony before this Commission, the Montana Public Service Commission, the Wyoming Public Service Commission, Minnesota Public Utilities Commission, and South Dakota Public Utilities Commission. In addition, during my tenure with the Illinois Commerce Commission, I testified in a number of cases before that Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide

an overview of our North Dakota natural gas operations, explain our request for a gas rate increase, and discuss the policies and reasons underlying the major aspects of the request. I will also identify the company witnesses in this proceeding.

Q. Would you provide a summary of Montana-Dakota's gas operations in North Dakota?

A. The North Dakota natural gas distribution system serves approximately 83,500 customers in 76 communities. The customer mix is about 86.5 percent residential, 13.3 percent firm commercial, with the small interruptible and large interruptible customers making up two-tenths percent of customers. In addition, gas is provided to the U.S. Air Force Base at Minot and a location in northeastern North Dakota. The residential, firm commercial, and small interruptible customers use natural gas primarily for space and water heating.

As such, Montana-Dakota's system has a low load factor with peak gas requirements occurring during the winter, with summer loads being small by comparison. The total annual gas used by North Dakota customers is 18.3 megadecatherms as projected for 2003 in this case. Consumption by customer

class is as follows: 43 percent residential, 31 percent firm commercial, 8 percent small interruptible, 12 percent large interruptible, and 6 percent U.S. Air Force.

Montana-Dakota's North Dakota gas service area is divided into two operating regions, with regional offices located in Bismarck and Dickinson. In addition, there are a number of district offices located in communities throughout the state. As of December 31, 2001 the company had 587 full and part-time employees who live and work throughout our North Dakota electric and gas service area.

Q. Mr. Fox, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for a gas rate increase?

A. Montana-Dakota is requesting an increase in general gas rates at this time because the current cost of providing natural gas service to our North Dakota customers is not adequately reflected in the -- excuse me -- is not accurately -- adequately reflected in currently authorized rates. It should be noted that this application does not include any cost changes related to the cost of gas which is

handled through the Commission authorized Purchased Gas Cost Adjustment tariff.

Q. Would you please explain the basic elements that make up the total costs of providing gas service and which of these elements is subject to regulation by this Commission?

A. Yes. The cost of providing natural gas service can be best broken down into two major categories. First, the cost of the gas delivered to the town border station where it leaves the interstate or intrastate pipeline and enters our distribution system. And, second, the cost of delivering the gas from the town border station through our distribution system to the individual customers. We call this portion distribution costs or non-gas costs.

Natural gas purchased from a producer or supplier is a commodity like wheat or corn and prices are not regulated. The charges for moving the gas to our distribution system on the pipeline system are regulated by the Federal Energy Regulatory Commission or other regulatory agencies. These two elements which we call, quote, unquote, gas costs, are passed on to our customers on a dollar-for-dollar basis as specified in the

Purchased Gas Cost Adjustment Tariff, and there is no profit made by Montana-Dakota. This portion currently comprises about 66 percent of a typical residential bill for gas services.

The distribution cost of our rate is regulated by this Commission and is the subject of this proceeding. This portion includes operation and maintenance expenses, depreciation, taxes, and a component for the opportunity to earn a return on the investment we have in facilities to provide natural gas service. The distribution costs are currently about 34 percent of a typical residential bill. The last time this portion of the rates increased was in 1994.

Q. What is the amount of the increase requested?

A. As will be fully explained by other company witnesses, the company is requesting an increase of $2,844,132 based on a projected 2003 test year.

Q. How will the requested increase affect the various classes of customers?

A. The proposed percentage change in rates by customer class is as follows: Residential, 4.6 percent change; firm general service, 4.6 percent; Air Force, zero; small interruptible, a negative 4.1

percent; large interruptible, zero, for a total increase of 4.1 percent.

Q. What are the primary reasons that Montana-Dakota needs an increase at this time?

A. The primary reasons are increased operating expenses, operation and maintenance costs, depreciation and taxes other than income and a higher required return on equity.

Q. When was the last general rate increase for Montana-Dakota?

A. Montana-Dakota's last gas -- I'm sorry. Montana-Dakota's gas rates were last increased in November 1994. The increase was $565,000 annually and was authorized in case No. PU-399-94-297.

Q. Have the gas generates changed since that time?

A. Yes. In case number PU-399-96-325 the gas generates were decreased by $800,000 or about 1.2 percent as a result of a settlement accepted by the Commission with a lower rate becoming effective January 15, 1999.

Q. Would you please explain how Montana-Dakota has been able to hold the gas rates down since 1994?

A. From 1994 through 2001 the Consumer Price Index has risen almost 20 percent. In spite of this

increase, we have been able to hold the line on our gas rates by finding ways of operating our business more efficiently and taking advantage of new technology where it makes economic sense to do so. For example, we have created a customer service center in Bismarck representing a one-stop shop for our customers. And we have installed computers in our servicemen's trucks allowing them to receive orders electronically, resulting in savings of at least one hour per day. We continue to look for opportunities to reduce costs and increase efficiencies. However, we now find ourselves in a position where despite our efforts, our best efforts, we must seek rate relief.

Q. What policy changes are proposed by the company in this filing?

A. We are proposing a change in policy regarding service lines. Montana-Dakota is proposing to own all service lines on a prospective basis. Currently, Montana-Dakota owns the service lines in the communities designated as rate zone 2 in its tariff. The customers currently own the services lines in the communities designated as rate zone 1. We are proposing that Montana-Dakota own and pay for, subject to appropriate extension policy

considerations or conditions, all new and replacement service lines on a prospective basis. This change will remove the distinction between rate zones 1 and 2 and will serve as a uniform policy on a statewide basis for all of our service areas. It will also align the ownership of the service line with the responsibility for ongoing testing and maintenance of the lines, which rests with Montana-Dakota and will avoid customer confusion and frustration in those instances when a replacement is necessary.

Q. Is Montana-Dakota proposing changes in its rate structure in this proceeding?

A. Yes. The proposed changes in the rate structure, which will be fully described by other witnesses, accomplish the objectives of providing a measure of stability for our customers, being simple to administer, and providing for enhanced fixed cost recovery.

I should note that our witnesses also present an alternative proposal in the event that the Commission finds the primary proposal to be unacceptable. The alternative proposal is fully described in the testimony of other witnesses. I would urge the Commission to accept the primary

proposal, as it provides the best fit with the objectives noted above.

Q. Will you please identify the other witnesses who will testify on behalf of Montana-Dakota in this proceeding?

A. Yes, I will. I should note at line 22, Mr. Pearce, that there's a correction. We should strike the word "electric" appearing in the last line thereof and substitute the words "natural gas." I will finish my answer.

In addition to myself --

MR. HOBERG: Mr. Fox, I'm sorry to interrupt you, but just for the court reporter's benefit, all the names, of course, are listed in the prefiled testimony. Please continue.

THE WITNESS: Stephen Gaske, President of Zinder Companies, Incorporated, will testify regarding the appropriate cost to common equity and overall cost of capital for Montana-Dakota's natural gas operations. Mr. Craig A. Keller, vice-president, controller and chief accounting officer for Montana-Dakota, will testify regarding the capital structure and overall debt and preferred equity costs. Ms. Rita A. Mulkern, regulatory analysis manager for Montana-Dakota, will testify

regarding the total revenue requirements necessary for Montana-Dakota's North Dakota gas operations.

Mr. Richard A. Espeland, vice-president, human resources for MDU Resources Group, Incorporated, will testify regarding the supplemental income security plan. Mr. Russell A. Feingold, managing director of Navigant Consulting, Inc., will testify regarding certain rate design policy matters. And Ms. Tamie A. Aberle, pricing and tariff manager for Montana-Dakota, will testify on the specific rate design proposals.

Q. (MR. PEARCE CONTINUING) Mr. Fox, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable because they are reflective of the total cost being incurred by Montana-Dakota in providing gas service to its customers. The proposed rates will allow Montana-Dakota the opportunity to earn a just and reasonable return on its North Dakota gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

Q. And to the best of your information and belief, does the testimony you have just given

coincide with the prefiled direct testimony that's marked as Exhibit A?

A. It does.

Q. Did you prepare that testimony originally?

A. I did.

MR. PEARCE: I'll offer Exhibit A at this time -- Exhibit 3. I have no further questions of this witness.

MR. HOBERG: Any objection to Exhibit 3, Mr. Binek?

MR. BINEK: No.

MR. HOBERG: Exhibit 3 is admitted.

Mr. Binek, do you have any questions on cross-examination?

MR. BINEK: Yes, I do.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Good morning, Mr. Fox.

A. Morning.

Q. Does MDU calculate its earned return each year for its North Dakota gas operation?

A. We do.

Q. What was the company's earned return on its gas operations during each of the years 1998, 1999, 2000, 2001?

A. I don't know right offhand. I can certainly provide that to you. We've filed an annual report with the Commission each and every year. I do know for 2003 without this rate increase, we would be a negative 4 percent.

(Exhibit 10 was marked for identification.)

Q. (MR. BINEK CONTINUING) Mr. Fox, I show you what has been marked as Exhibit 10 and ask if you can identify that exhibit? First of all, I guess I should ask if you've seen that previously?

A. I have not.

Q. Okay. Do you recognize that as an exhibit that has been docketed in an MDU case by the Public Service Commission?

A. I do not.

MR. HOBERG: Mr. Pearce, did you get a copy?

MR. PEARCE: No, I didn't. I'm wondering what it is.

Q. (MR. BINEK CONTINUING) Can you identify what the exhibit is, please?

A. It's a memorandum, internal memorandum, I believe, written by Mike Diller of the Commission staff, and it's written to Commissioners, Illona and Bill. And --

Q. What is the date of that document?
A. September 3rd, 2002.
Q. Okay. And what does it refer to?
A. It refers to 2001 annual reports.
Q. And in that document there are a number of companies listed, including MDU Gas, and it shows returns on equity earned by utilities for the four years that I had asked you about; is that correct?
A. It does.
Q. Do you have any reason to doubt the figures that are shown in that exhibit?
A. I do not.
Q. And would you accept the figures shown on that exhibit subject to check, subject to your own verification?
A. I would.
Q. What is the ROE shown for the year 1998 for MDU?
MR. HOBERG: I think we better have it offered and admitted before we testify.
MR. BINEK: I'm sorry. I will offer Exhibit 10.
MR. HOBERG: Any objection to Exhibit 10, Mr. Pearce?
MR. PEARCE: I guess I'm tempted to object

for lack of foundation since the witness who prepared it is not being offered, but given that Mr. Fox has indicated he would accept the numbers subject to verification, I don't have any objection.

MR. HOBERG: Okay. Exhibit 10 is admitted. Mr. Binek, please.

MR. BINEK: Thank you.

Q. (MR. BINEK CONTINUING) Now, Mr. Fox, would you -- for the year 1998 what is the ROE shown for MDU gas?

A. 14.55.

Q. And 1999?

A. 10.25.

Q. 2000?

A. 11.92.

Q. And 2001?

A. 11.90.

Q. And what is the four-year average?

A. 12.16.

Q. Okay. And it's your position that -- is it your position that an 11.9 return on equity is inadequate?

A. Dr. Gaske in this case has pointed out that because of the risk associated with our gas business, we should be earning considerably higher

than 11.9.

Q. So the earnings that you had in 2001, 11.9 were inadequate; is that your testimony?

A. That's correct.

Q. And the four-year average of 12.16 is adequate; is that also your testimony?

A. Let me explain that. It's inadequate based upon Dr. Gaske's testimony in this case, but keep in mind, that we are dealing with 2002 and 2003 is just right around the corner and we know based upon our rates-of-return analysis that we will be earning a negative rate of return for 2003 without the proposed rate increase. In fact, in 2002 we will be at zero. So we've had a drastic change in the last two years.

Q. Will the 2002 return be influenced by the very mild winter we had last year?

A. This is normalized.

Q. Okay. And what is your predicted return for 2002 under normalized weather conditions?

A. I believe it's zero. We have witnesses here which can attest to that and subject to check. It's considerably lower than what you find here for 2001.

Q. Is it true that you are predicting a

significant decline in your earned return between now and the end of 2003?

A. I am.

Q. Okay. On page 6 of your testimony you mentioned that the last gas rate increase was in 1994, and that that was a relatively small increase, $565,000. What did that amount to in percentage terms?

A. I don't recall.

Q. Okay. In 1999 you had a rate reduction of 800,000. Do you know what the percentage reduction was then?

A. In my testimony I say about 1.2 percent.

Q. Okay.

MR. HOBERG: Mr. Binek, can you bring your microphone over closer? It's on, isn't it?

MR. BINEK: Yeah.

Q. (MR. BINEK CONTINUING) Earlier this year the Commission reduced your electric rates; isn't that correct?

A. It did.

Q. What is it about the gas business that causes it to require an increase when the electric side of your operations justify a rate decrease?

A. Well, they're really two different

businesses. Dr. Gaske, I think in his testimony laid out very well the reasons. You know, we're a small gas utility --

MR. HOBERG: I'm sorry. Mr. Fox, can you bring your microphone a little closer, too? They are having a little trouble hearing both you and Mr. Binek in the back.

MR. BINEK: We're both soft-spoken.

THE WITNESS: Can you now hear me better?

MR. HOBERG: Yes. We can hear you upfront. It's just having trouble back --

THE WITNESS: I'll try to do better. We also have competition for alternate fuels. And, thirdly, we have a rate design that's in effect right now that doesn't allow us to fully recover our fixed cost of operations. And so Dr. Gaske does a good job of looking at that and I happen to agree with what he said. He said, I think, in his testimony that because of the smallness, which means that, you know, small change in one of our expense items or whatever creates a big difference in whether we are able to earn a return or not, an adequate rate or return on our business. And he said that's worth 100 basis point in and of itself simply because we're that small.

Q. (MR. BINEK CONTINUING) You mentioned competition from alternate fuels. What competition do you face from alternate fuels?

A. Propane, coal, and --

Q. How --

A. Excuse me. Gas bypass.

Q. How much competition do you face from coal?

A. Well, I have a neighbor -- I'll be happy to supply some of that, but we do have some competition. In fact, I've got a residential customer in my neighborhood that uses coal.

Q. It's very, very minimal, isn't it?

A. It is from a residential standpoint, but keep in mind that folks like the larger customers, such as out here at the Tesoro -- did I say that correctly? Amoco --

COMMISSIONER WEFALD: Tesoro.

THE WITNESS: Tesoro is, in fact, looking at that very option, whether to burn coal or continue with gas, and we, in fact, have lost a portion of that gas load now to gas bypass.

Q. (MR. BINEK CONTINUING) Propane, aren't you, in fact, putting in -- extending your natural gas delivery systems in the Bismarck area out into areas previously served by propane?

A. We are, but we're not picking up, you know, 100 percent or even 90 percent of that.

Q. But you are picking up a good majority of the customers out there that were previously on propane, aren't you?

A. We're primarily picking up those customers who have yet not committed, picking up the new customers. We're hoping for a conversion rate around 60 percent on propane out there. Certainly not the 100 percent. So how pervasive it is, it's there and continues to be there.

Q. Okay. So you had 100 percent of the customers out there using propane prior to extending your lines, now you're going to -- you're hoping to acquire 60 percent of those people presently using propane, is that --

A. Or said another way, Mr. Binek, we will lose 40 percent of that load out there or not be able to --

Q. Well, you're going to gain load out there that is presently served by propane, right?

A. That's correct.

Q. Okay.

A. My statement is also correct, too.

MR. HOBERG: Mr. Binek, your question -- I

don't know that we sufficiently defined what "out there" means.

Q. (MR. BINEK CONTINUING) I'm thinking specifically about areas north of Bismarck where lines are being -- distribution lines are being extended by MDU gas.

A. For the record I would clarify. We do have a new project. We call it the northeast Bismarck project, where we are spending monies to provide gas service to customers in that area, that hopefully will have some growth, plus pick up some of the ones that are now using propane.

Q. Thank you.

MR. HOBERG: Thank you.

Q. (MR. BINEK CONTINUING) And the other competitive fuel is oil?

A. Could be. For the larger customers you have coal, oil, bypass, primarily.

Q. Okay. The bypass would be served by the Williston Basin Interstate Pipeline?

A. That's one bypass that I'm thinking about. They actually went to Williston Basin.

Q. Okay. And that's an MDU Resources company?

A. It is, but it's money out of my pocket.

Q. Sure. I understand that. Has inflation

accelerated since 1994?

A. Yes, it has.

Q. Do you have any basis for assuming that inflation will accelerate between now and the end of 2003?

A. When you say accelerate, I'm not sure. We know we have inflationary pressures of probably three, three and a half percent per year.

Q. Will it get worse?

A. I have no idea.

Q. On page 7 of your testimony you state that you have so far avoided a rate increase by operating your business more efficiently and taking advantage of new technology. Have you suddenly lost the ability to operate more efficiently?

A. If I may, I'll go back in history a little bit. In 1994 we had our last rate increase application in here. Since that time, our employees -- we've had a decrease in our employees of over 30 percent. And that hasn't come about by huge layoffs. That came about by attrition and finding more efficient ways of doing things. Another statistic that I like to think about is -- let me check my notes here, if I can find it real fast -- is that in 1994 one employee -- I'm sorry --

248 customers was being served by one employee. In 2001 one employee was serving 370 customers. Just means that we've tried to find better ways of doing that.

And we continue to look for that, but I don't foresee us continuing that type of rapid growth in trying to achieve efficiencies that would mark that rate of serving more customers with less employees. In fact, we've kind of flattened in the last year or two. I think there is just so much that you can do. Although, I can tell you we have our employees out there looking for it. And that's where most of our ideas come from, is from our employees. And we have several programs that are geared to do that, to reward and provide some incentive for coming forth with ideas, and most of them are just recognition-type things.

Q. Have you exhausted all possible new technologies that might help you cut costs?

A. Again, probably not, but keep in mind, Mr. Binek, if I may -- can you still hear me all right?

MR. HOBERG: Yes.

THE WITNESS: -- is that we -- and, here again, to give you an example, we are small. And,

again, to give you an example of what that smallness can do for you, we had hoped to automate our meter reading across our entire service area, including that of North Dakota, but we find out with the sparseness of our operation and given that we serve very few so-called large towns, Bismarck, Billings, Montana being the largest ones, Rapid City, we certainly -- we could not commit the monies that would have been necessary to do that. So we went halfway. We decided to upgrade our semiautomatic ICON meter reading system to, again, accord new technology, but certainly not to the point where we would have liked to.

So it's looking, but it's -- you know, you look at all across that business venture, I don't see anything on the horizon other than what we've done today, such as the customer service center, automating and consolidating our meter reading. We do joint trenching. You know, we just keep looking under every little piece of dirt, so to speak, to try to figure out ways of doing it. But when you say "all," no, I wouldn't say all, but certainly we have come a long ways in the last five, six years.

Q. (MR. BINEK CONTINUING) As far as numbers of customers, have you been gaining in customer

count?

A. Not particularly.

Q. You have had some gains?

A. We have had some gains, but nothing materially. We grow about 1 percent or less per year in the gas business. Unless we take on a new project like northeast Bismarck, there isn't a lot of growth other than that.

Q. Could you explain what joint trenching is?

A. That means we get together with telecommunication companies, other utilities, anybody that's putting a hole in the ground and trenching it for a ways, we'd like to drop our underground facilities in there as well and that's worked out very well for us.

Q. So you're doing that right now?

A. We are doing that now.

Q. Are you doing that in northeast Bismarck as well?

A. We are wherever the opportunity comes along, especially with the telecommunications people, but that's slowed down, too.

Q. On page 7 of your testimony you propose a policy change with regard to the ownership of customer services. Does that policy change

influence your need for more revenue and, if so, how?

A. It does. We think we'll spend about -- other witnesses have it. It's about $500,000 a year, and that's included in this case.

Q. On page 8 you mention rate structure changes. Do those rate structure changes influence your need for more revenue and, if so, how?

A. It does not.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, do you have any questions of Mr. Fox?

COMMISSIONER REINBOLD: A couple. Thank you.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. First of all, I want to get back to the residential customers burning coal in the City of Bismarck. Do you have any idea the numbers you're talking about, the number of households that are taking advantage --

A. It would be very small for the residential. I happened to use that. I kind of bristle at that every time I go by that person's home. That's the

reason I brought it up. But the coal, the competitive feature of that would be in the large customer list. And the reason for that, if the cost of gas goes up -- and primarily we're talking about the cost of gas that we don't control. We're talking about the wholesale. But if that would go up materially, then those folks start looking at different alternatives. The distribution portion of it doesn't have much influence on this.

Q. The reason I wanted to bring it up again is because it surprised me. I didn't know that happened.

MDU, you have gas operations in other states other than North Dakota. You have Montana?

A. Montana, South Dakota, and Wyoming.

Q. And are they in a similar calendar mode of applying for a rate increase, or don't you know?

A. Yes. In every state we are filing for a rate increase, either have or will. We filed in the State of Montana. We've already received an interim rate increase there. And we expect the process in Wyoming to go rather fast. The idea in most cases, and the other witnesses here will have a better feel for that, but we are hopeful of putting increases on the distribution site, increased rates in effect for

this heating season.

Q. You mentioned your customer service center and we've heard presentations on that. It's fascinating what you're doing. Can you elaborate a bit on what the customer service center does if somebody calls in?

A. Yes. Yes, I can. Am I close enough to this? A few years ago we decided to centralize what we call our customer service point. Historically, we would have a person located in each of our major areas talking to our customers, answering their inquiries, their questions. And we thought that we could consolidate that and still give personalized service to each customer by doing a couple things. One is when they call in, they would get a real person that would be able to meet their needs. And, secondly, through increased training, 8 to 10 weeks of training for each of these people, we thought that they would be able to handle particular questions, inquiries. In fact, they actually dispatch calls to our servicemen, that type of thing, in addition to that.

So we thought we could do that with a decreasing -- without decreasing our request time for service, decrease our customer acceptability. In

fact, I think it's enhanced our customer acceptability since we started that. There are a lot of things that have been very favorable about that and, plus, we've been able to save a considerable amount of money on an annual basis as a result of that.

Q. Better service and save money at the same time?

A. That's correct.

Q. You say when I call in or somebody calls in, you talk to a real person?

A. They do. I say that versus calling, as we sometimes do, call for help and we find that we have to punch one or two or three or four a couple of times in order to get someone to answer our questions and sometimes we never get someone to answer our questions. So we don't do things that way.

Q. Is there any way that you can take your experiences of talking with a real person and teach this to the telephone industry in the state?

A. Well, I didn't mention them by name, but you're right on track.

Q. I could. That's enough insults for now. Next.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. You mentioned Tesoro Company. What impact does this one company have on the income of Montana-Dakota Utilities?

A. Well, we have a witness that would have it. Ms. Mulkern has that in her cost of service.

Q. Then I'll just wait and ask Ms. Mulkern. That's fine. And then each one percent -- we received this memo --

MR. HOBERG: Exhibit 10.

Q. (COMMISSIONER WEFALD CONTINUING) Exhibit 10 from staff. And it shows that 2001 11.9 percent rate of return. In your testimony you have said that you anticipate a rate of return of zero in 2002; is that correct?

A. 2003. No, 2002. 2003 would be negative.

Q. So can you share with me the difference in income or the difference in expenses that would relate to a drop from 11.9 percent to zero?

A. I can, but I think what would be best, Commissioner, if you can wait for Ms. Mulkern to come. She has all the full facts in front of her.

Q. Okay. And then in your expansion into north Bismarck, how are costs recovered for that expansion, and are they included in your cost for 2002 when you anticipate a rate of return to be zero?

A. Northeast Bismarck is included in this rate case.

Q. And what are the --

A. That's a 2003 test year.

Q. And that's a 2003 test year?

A. Mm-hmm.

Q. So what are the costs for that expansion, and how are they recovered?

A. Let's see, how are they recovered? They are included in this rate case so it would be recovered through the rates of all the folks, ratepayers in the State of North Dakota.

Q. Do you have an expansion tariff in place so that the customers in those areas pay the bulk of the expansion, or are the bulk of the expansion costs paid by all the ratepayers of the State of North Dakota?

A. There's a policy in place for that and, again, if I may, Ms. Aberle or Ms. Mulkern could answer specific questions on that.

COMMISSIONER WEFALD: Thank you. That's all my questions.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

EXAMINATION

BY COMMISSIONER CLARK:

Q. Just one question. Do you have any other major expansion plans outside of northeast Bismarck in your service territory area?

A. In North Dakota, Commissioner?

Q. Right.

A. That's the only one I can think of right now. Like I said, the gas business is very slowly growing. It's less than 1 percent per year.

Q. Okay. And that would include both residential and industrial, you don't have any industrial-type expansion projects on the horizon, at least that would be included in this test year?

A. Nothing that -- nothing that we haven't had in the past.

COMMISSIONER CLARK: Okay. That's all I have. Thank you.

MR. HOBERG: Thank you, Commissioner Clark. Commissioner Reinbold, you have another question?

FURTHER EXAMINATION

BY COMMISSIONER REINBOLD:

Q. One other question. Do you serve the University of Mary with natural gas?

A. Yes.

COMMISSIONER REINBOLD: You do. Thank you.

MR. HOBERG: Thank you, Commissioner Reinbold. Mr. Pearce, anything on redirect?

MR. PEARCE: No. I have no questions.

MR. HOBERG: Thank you. Mr. Binek, anything further?

MR. BINEK: No.

MR. HOBERG: Thank you, Mr. Fox.

Let's take about a -- let's be back at 10 after 10:00, about a nine-minute recess. We'll start at 10 after 10:00.

(A recess was taken.)

MR. HOBERG: We're back on the record after a short recess. And I apologize. I neglected to ask for an appearance by Commission advisory staff, and at this time I will ask Ms. Jeffcoat-Sacco to make an appearance for Commission advisory staff.

MS. JEFFCOAT-SACCO: Commission advisory staff in this case is myself, Mike Diller, and Jerry Lein. And for purposes of this case, if there are

some questions of advisory staff during the hearing, I'd request that Mike be able to ask those, if that's acceptable.

MR. HOBERG: Any objection, Mr. Pearce?

MR. PEARCE: No, that's no problem.

MR. BINEK: No.

MR. HOBERG: Did you have any questions of the first witness?

MR. DILLER: I can ask the question I had of one of the other witnesses.

MR. HOBERG: Okay. Thank you, Ms. Jeffcoat-Sacco and Mr. Diller. You may not be asking questions, as I understand, of every witness, but you'll indicate to me if you have a question?

MR. DILLER: That's right.

MR. HOBERG: Okay. Thank you. Your next witness, please, Mr. Pearce.

MR. PEARCE: Thank you. Before I call the witness, I think there's one matter I'd like to clarify. I'm not quite sure what's the best way to do it. It turns out apparently there's a significant error in Exhibit 10. The 2001 MDU gas return does not correspond to the return that was actually filed with the Commission in the annual report. Apparently, it was mistranscribed when this

exhibit was made up, so I'm not quite sure what's the best way to do that. We can take judicial notice of the report that's on file with the Commission.

MR. HOBERG: This is on file in another matter?

MR. PEARCE: This is the annual report that the company has filed and I think Mr. Diller based his Exhibit 10 on. Perhaps maybe since he's now participating in the proceeding, he could simply clarify that there's apparently a transcription error made in preparing Exhibit 10.

MR. HOBERG: Is there an error, Mr. Diller?

MR. DILLER: Yes. I looked at MDU's annual report for its gas operation. It appears I picked up the 2000 number and put it in 2001. The actual earnings reported by MDU, I believe, is 1.6 percent for 2001, rather than 11.9.

MR. HOBERG: 1.6 percent. Why don't we just make that correction there? Is that sufficient, Mr. Pearce?

MR. PEARCE: Yes, that's fine. The report actually says 1.616, but 1.6 is fine.

MR. HOBERG: And then, of course, that would make a difference on the four average, too,

and make a difference on the average for all. For the purpose of this hearing are we mostly concerned about those four numbers from 1998 to 2001?

MR. PEARCE: That was the point of the exhibit, I think.

MR. HOBERG: Okay. Then that exhibit will be corrected as indicated. Thank you, Mr. Pearce. Your next witness, please.

MR. PEARCE: We'll call Dr. J. Stephen Gaske.

MR. HOBERG: Dr. Gaske's direct testimony does appear as Exhibit 4 in Docket No. 1.

Dr. Gaske, did you hear -- you can sit down.

THE WITNESS: I thought you'd swear me in.

MR. HOBERG: I am going to. You can sit down while you're doing it.

Dr. Gaske, did you hear the admonition I gave in regard to perjury?

THE WITNESS: Yes, I did.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce,

please.

J. STEPHEN GASKE,

being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Dr. Gaske, have you prepared and had prefiled in this case prepared direct testimony of J. Stephen Gaske?

A. Yes.

Q. And if you were asked the same questions appearing in Exhibit 4, would your answers be the same today if you gave them live in this proceeding?

A. Yes.

Q. And to the best of your information and belief, is all the information contained in that testimony true and correct?

A. Yes.

MR. PEARCE: I will offer Exhibit 4 at this time and I'm not going to reread the testimony.

MR. HOBERG: Thank you, Mr. Pearce. Any objection to Exhibit 4?

MR. BINEK: No.

MR. HOBERG: Okay. Exhibit 4 is admitted. Are you tendering the witness for --

MR. PEARCE: Yes.

MR. HOBERG: Okay. Thank you, Mr. Pearce. Mr. Binek, do you have any questions of Dr. Gaske?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Dr. Gaske, on page 2 of your initial testimony, and that is Exhibit 4, at lines 8 to 10, you state that you have filed cost of capital and capital structure issues in six states, including North Dakota.

Was your latest North Dakota appearance in Case No. PU-399-01-186, which was MDU's electric service rate case?

A. Yes.

Q. In that case did you argue for the inclusion of an upward adjustment in the return to equity to account for flotation costs?

A. Yes, I did.

MR. BINEK: Okay. Your Honor, at this time I would like to have Mr. Gaske refer to some findings in this case. Do you wish to have this marked as an exhibit or just --

MR. HOBERG: Let's take official notice of that. I don't think we need to mark it as an

exhibit.

MR. BINEK: I do have copies, if people would like copies.

MR. HOBERG: That may be a good idea to put copies out for us, please.

MR. HOBERG: And, again, for the record, that's Case No. PU-399-01-186. Mr. Binek, please.

Q. (MR. BINEK CONTINUING) Okay. I've handed you a copy of the decision that the Commission issued in that case. The decision is dated April 24, 2002. And I would ask if you would please read paragraphs 14 and 15.

A. (Witness reviews document.)

MR. HOBERG: You don't want him to read them out loud, do you?

Q. (MR. BINEK CONTINUING) Yes, I would like to have you read them out loud.

A. "Under cross-examination, Gaske provided no empirical data to show that disallowing flotation costs would hinder the issuance of stock. On the contrary, Gaske agreed that most regulatory commissions do not allow flotation costs."

"Given that staff has provided evidence based on historical information, we find no need to rely on the theoretical" --

MR. HOBERG: Dr. Gaske, I'm sorry. Can you speak up a little bit, please? We're having a little trouble.

THE WITNESS: "Given that staff has provided evidence based on historical information, we find no need to rely on the theoretical information provided by MDU. In addition, Gaske admitted that most regulatory commissions do not allow flotation costs. The evidence indicates a negligible amount of flotation costs in the instant case. Therefore, the Commission will not include flotation costs in the determination of return on common equity."

Q. (MR. BINEK CONTINUING) Thank you. Your flotation cost approach in this case is essentially the same as your approach in MDU's electric case that was decided on April 24th of 2002; isn't that correct?

A. Yes, it is.

Q. And it's also correct that the Public Service Commission rejected the inclusion of flotation costs in that case --

A. Yes, that's true.

Q. -- is that correct? And it's also true that most state public utility commissions have

rejected the inclusion of flotation costs in determining the cost of common equity; isn't that also correct?

A. Some have accepted it and some have rejected it.

Q. Most have rejected it; would you agree?

A. At this point, yes.

Q. Where in your direct or rebuttal testimony in this case do we find empirical data to show that disallowing flotation costs would hinder the issuance of stock?

A. I never make the claim that it hinders the issuance of stock. What I do say is that without the allowance, an issuance of stock will result in a confiscation of property of the existing investors. So that's a very different claim than the one that you've asked me about. I don't base my claim on empirical evidence that they will be unable to issue stock. They will be unable to issue the stock on reasonable terms.

Q. Aside from North Dakota, what were the other five states where you filed testimony on cost of capital?

A. Let's see. Montana, Wyoming, New York, South Dakota, and actually I've done it in Alaska.

Q. In how many of those states did you recommend a flotation cost adjustment to the return on equity?

A. All of them.

Q. And how many of those states did the Commission accept your recommendation?

A. Actually, I should add I've also testified on flotation cost adjustment in a property tax case in Wyoming and, in fact, testified on that on two occasions.

Q. Okay. But in utility cases you're talking about the previous ones you mentioned?

A. In utility cases, most of those were settled or have not had a decision. The Montana case they did not allow flotation costs. In the Wyoming property tax case they did not allow it the first time, but the second time around I think I did a better job of explaining it and they did agree that a flotation cost adjustment was appropriate in order to be able to issue common stock on reasonable terms. It's an appropriate part of the cost of capital.

Q. Okay. But that was not a utility case?

A. No, it was not. But my point is that Commissions have rejected this issue in the past and

then turned around and realized and understood the issue so that they did allow it. They changed their minds.

Q. What rates of return did the Commissions allow in gas -- let me go back. Were any of these cases that -- the utility cases that you talked about gas utility cases?

A. Yes.

Q. And how many of those were gas utility?

A. I probably -- I don't recall exactly, but maybe about five of them.

Q. What rates of return did the Commission allow in each of those gas distribution cases?

A. To my recollection, the only one that went to a decision was a Montana case and I believe it was 11.7, but I would have to check to tell you.

Q. Okay. None of them have --

A. It might -- it might have been higher than that. I don't recall.

Q. I'd like to have you turn to your Exhibit JSG-2.

COMMISSIONER REINBOLD: What page is that?

MR. BINEK: It's Exhibit JSG-2.

MR. HOBERG: Toward the end of Exhibit 4, his testimony, about two pages before the end.

Q. (MR. BINEK CONTINUING) On page 1 you provide a number of rates of annual change for prices and gross domestic product. They end in 2001.

MR. HOBERG: I'm sorry. I misspoke. I was on page 8 when I said that. It's closer to about 10 pages from the end, JSG-2.

THE WITNESS: I think you're on the right page.

COMMISSIONER CLARK: Schedule 1.

COMMISSIONER WEFALD: Is it in the rebuttal testimony or the original testimony?

THE WITNESS: Original testimony.

COMMISSIONER WEFALD: Thank you. That will help me find it.

MR. HOBERG: Schedule 1, where it says 1 of 3 pages.

THE WITNESS: I think that's what he's referring to.

MR. HOBERG: Does everyone have it?

COMMISSIONER WEFALD: JSG-2, and which page of JSG-2 are we on?

MR. BINEK: Page 1 of 3.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Mr. Binek, please.

MR. BINEK: It's Schedule 1, page 1 of 3.

Q. (MR. BINEK CONTINUING) Okay. On page 1 you provide a number of rates of annual change for prices in gross domestic product. They end in 2001, which is now more than nine months ago. What has happened to these indicators since last December?

A. I believe in the early part of the year there was relatively rapid growth in the economy. And I believe it slowed down since then, and I don't know what's going on right now. I do know that right now there's a debate whether we're in or going into another recession, but we really won't know that until the quarter is out.

Q. What about consumer prices, what's happening there?

A. I don't have that information.

Q. On page 2 of that exhibit you show a number of interest rates, but your series end last January. Can you provide the latest interest rates and match these series?

A. Let's see. The last one I had was as of the end of July, the corporate average, which was 7.38 in January, went down 11 basis points to 7.27 percent. The A-rated public utilities, which has been 7.66 percent, went down to 7.31 percent. And

the Baa-rated utilities barely changed at all, went from 8.13 to 8.07 percent. Since that time I don't have the exact numbers. I believe the numbers have gone down some. That, I guess, brings you up another six more months.

Q. Okay. So the interest rates generally have decreased; do you agree?

A. Yes. The Baa barely as much, but it's down.

Q. Do you know whether it's true that interest rates are now the lowest that they've been in decades?

MR. HOBERG: By "decades" you mean what, the last --

MR. BINEK: Last couple, three.

MR. HOBERG: Three decades.

THE WITNESS: It depends on what interest rate you're talking about. One of the things that has occurred in the past year is that investors have been very leery of investing in almost anything that has any risk at all attached to it. So they have been reluctant to be in common stocks or even risky bonds. The treasury bill rates are the lowest they've been in decades. The U.S. Treasury bond rates are also the lowest that they've been in

decades. However, if you look at the Baa public utility bonds, right now they're essentially higher than they were in 1999 or '98. Approximately where they were in '97. Higher than they were in '93. They're about where they've been for the last decade.

So to answer your question, depends on whether you're talking about extremely low-risk instruments. Those are low. Investors want those very badly right now because there's a great deal of uncertainty in the market and the economy, but your question is not true if you're talking about public utility bonds.

Q. (MR. BINEK CONTINUING) On page 3 of that same exhibit, you show average return on the book value of equity since 1977 up through 2001. What has happened to returns on equity during the past nine months?

A. I would imagine that they are pretty abysmal, but I don't know the numbers on that.

Q. Okay. On page 11 of your testimony you present the discounted cash flow formula. Is it true that the only difference between your presentation of this formula and that of Mr. King is that you increase the next year's dividend by a

factor of .625 and that Mr. King increases it by .5?

A. As far as the basic general formula, yes, that's correct.

Q. Is the principal reason for this difference your belief that Mr. King has failed to recognize the present value of future dividends and dividend increases?

A. I think that the best way to describe it is that he's neglected to pay any attention to the time value of money during the initial year.

Q. And that's present value, isn't it?

A. Well, the whole discounted cash flow model looks forward basically into an infinite period of time in the future and is based on discounted cash flow. The portion of the model that deals with that adjustment factor really is looking at the first year of an infinite number of years. That dividend tends to be the most valuable because it's one you get the soonest, and to the extent that you're getting it on a quarterly basis, the first one you get is more valuable than the second, more valuable than the third, et cetera, as long as the dividend doesn't change. And so I think the real difference between the two of us is a relatively small one. I recognize the time value of money and he doesn't.

Q. This really doesn't amount to much of anything as far as this case, does it?

A. No. That's why I was a little bit surprised that he put it in his rebuttal testimony.

Q. I recall an electric case we spent a lot of time on this issue for very little money.

A. Yeah. And I couldn't understand why he kept getting the math wrong and still does.

Q. Perhaps he might not think he's got it wrong.

A. It really goes -- it's not a real big dollar thing. It really goes to a question of whether you can do the math right.

Q. I think we'll let him respond to that one.

A. And that may be something -- well, I'll leave it at that.

Q. Please turn to page 5 of Schedule 2 of your Exhibit JSG-2.

COMMISSIONER WEFALD: Same book?

MR. HOBERG: Yes, same book.

COMMISSIONER REINBOLD: What page?

MR. BINEK: Page 5 of Schedule 2.

COMMISSIONER WEFALD: 5 of 9?

MR. BINEK: Of 2. Oh, 5 of 9, yes.

Q. (MR. BINEK CONTINUING) Is this the page on

which you developed the growth rates you use for your six proxy group companies?

A. These are the factors that I gave the most weight to, yes.

Q. The first column is Zacks five-year growth estimate, and the second column is your retention growth calculation; is that correct?

A. That's correct.

Q. Is it true that for five out of these six companies the Zacks forecast is higher than the retention growth forecast?

A. Yes.

Q. The third column is labeled "weighted average." Is that the weighting of two-thirds Zacks and one-third retention growth?

A. Yes.

Q. On what basis did you decide to make that weighting between the two growth estimates?

A. There were two factors that came into play. One is that I normally think of the retention growth rate as being sort of a baseline, relatively stable number that investors can look at as being a base level of growth throughout the life of the project or the company as long as they maintain that. The Zacks earnings growth estimates take into

consideration a lot of other ways that a company can grow other than by retaining earnings and reinvesting it to increase common equity just through retained earnings. So the Zacks earnings estimates which are put together by analysts and forecasts tend to include the other methods that companies can grow by. For these companies I think people who buy common stock place a fairly good amount of weight on those estimates and stock prices and dividend yields are dictated to a large extent by those analysts' estimates. So I tended to give them a little more weight.

The second reason I used that approach is that it somewhat mimics an approach that the Federal Energy Regulatory Commission actually requires almost as a generic approach where they give two-thirds weight to the Zacks earnings estimates and a one-third weight to the projected growth in the Gross National Product or Gross Domestic Product, rather than retention growth. So to my mind, it's a good way to put together a combination of the two that smooths out aberrations that may occur in one growth rate or the other and get a pretty good estimate of what investors reasonably expect over a long period of time.

Q. Isn't it true that two companies, Keyspan and Laclede Group, account for the highest observations?

A. Yes, highest observed growth rates.

Q. And those high growth rates for Keyspan and Laclede rates carry over to the next page, page 6, to yield the two highest rates of return; isn't that also correct?

A. Yes. Keyspan and Laclede also have the highest dividend yields.

Q. Did Mr. King include Keyspan in his comparable companies?

A. No, he did not.

Q. Do you know why Mr. King excluded Keyspan from his group of comparable companies?

A. He used different selection criteria than I did. Keyspan derives less than 75 percent of its earnings from utility operations or gas utility operations.

(Exhibit 11 was marked for identification.)

Q. (MR. BINEK CONTINUING) Would you please identify what has been marked as Document 11? I guess I also would like to say, would that be the cover page, index page, and page 27 of the 2001 form 10-K for Keyspan Corporation?

A. Yes.

MR. BINEK: I would offer Exhibit 11.

MR. HOBERG: Any objection to Exhibit 11?

MR. PEARCE: No. Assuming it is what it purports to be, I have no objection.

MR. HOBERG: Exhibit 11 is admitted.

Q. (MR. BINEK CONTINUING) Mr. Gaske, I'd like to have you look at the first line of the first column on page 27. Could you tell me what the number there represents?

A. It's the gas distribution revenues of Keyspan during various years in the recent past.

Q. It shows gas distribution revenues in 2001?

A. Yes, it does.

Q. What is that number?

A. 3.6 million.

Q. Now, I'd like to have you drop down a few lines -- is the number billion?

A. Yes. The numbers are expressed in thousands of dollars, so, yes, $3.6 billion.

Q. And now would you drop down a few lines and read the number for total revenue?

A. $6.6 billion.

Q. Would you agree that gas distribution accounts for almost exactly one-half of Keyspan's

total revenue?

A. A little more than that, but, yes. Somewhere in the 50 percent range, 50 to 60.

Q. The other company with very high weighted growth rate on page 5 of Schedule 2 is Laclede? Or I think you refer to as Laclede?

A. Yes.

Q. Okay. Could you explain how Laclede could generate a 12 percent annual growth in earnings when its retention of earnings would allow it to increase by only 4.2 percent?

A. Laclede, at the time that I did my testimony, the most recent Value Line page for them indicates that it had recently formed a holding company and that Laclede was going to begin essentially starting up some new businesses and getting into some other new lines. The Value Line ultimate conclusion was that Laclede's expansion into unregulated industry boosts its long-term earnings prospects.

So although Laclede did not have much in the way of other investments and other lines of business, particularly unregulated ones at the time, and still doesn't have a whole lot, investors were clearly expecting that they would get into some

additional lines of business and that in the long run that they were going to boost their earnings' growth rate above the growth rate that would be sustained by book value growth.

Q. So Laclede's high return is related to unregulated activities; would that be correct?

A. Not the current required return of the company at the time. The high growth rate and perhaps the dividend yield was lower than it might otherwise have been because of that high expected growth rate, but at the time the company was primarily a distribution company.

Q. But the high return that you're showing is due to unregulated activities, isn't it?

A. They didn't have much in the way of unregulated activities at the time. The high growth rate is based on the expectation that in the future they're probably going to make more money than they can make on unregulated operations, but there's a very different question there, because the current return reflects to some degree unregulated operations in the future, but it primarily reflects what they have in place and what their current business is, what their prospects for that business are and the risks attached to it. So you can have

high growth expected in the future without necessarily having a lot of risky investments right now.

In addition, the -- I suspect that at one level it's probably good for the Laclede investors for the company to diversify into a few other lines of business to more or less diversify the company in case something happens with the gas distribution business.

Q. Didn't Mr. King produce as his Exhibit CWK-5 a Zacks report that showed Laclede's consensus growth at 4.25 percent?

A. Yes. Later in the year after I prepared my testimony the projected forecast for Laclede went down. I actually didn't look to see what happened with the other companies, but he did produce the Laclede one and it went down from 12 to 4.

Q. Turning to page 6 of your Schedule 2, would you agree with me that if you left out Keyspan and Laclede, the average return would be considerably less than the numbers you show there?

A. The average for -- if you left the two out, the average cost of capital would be -- instead of 12.83, it would drop to 11.85. The median would drop from 12.51 to 12.4. So your median would drop

about 11 basis point. So, yes, it's a slightly lower number. Not a lot, but it's slightly lower.

Q. I'd like to have you turn to page 7 of Schedule 2, Exhibit JSG-2. Do we find again that Keyspan and Laclede generate by far the highest rates of return?

A. Laclede does. The Keyspan depends on your definition of "by far," but, yes, it is about 80 basis point higher than the next one.

Q. Now, I'd like to turn to your primary DCF analysis. A discussion of that begins on page 20 of your testimony.

COMMISSIONER WEFALD: Which testimony is that -- the original testimony?

MR. BINEK: That's the original.

Q. (MR. BINEK CONTINUING) The growth rate that you use for this analysis as a range --

A. Could I ask you to wait for a moment?

Q. Sure.

A. Okay. Where was it that you were going?

Q. Okay. Page 20.

A. I'm there.

Q. Okay. The growth rate that you use for this analysis is a range, isn't it?

A. Yes.

Q. That range is presented on lines 14 and 15 of page 21 as 6.75 percent to 7.75 percent; is that correct?

A. Yes.

Q. How did you arrive at that range?

A. I considered a variety of factors. I believe that natural gas is going to tend to become a more important fuel source in the future, at least in some places. I also looked at the data that you pointed me to earlier. If you go to Schedule 2 of Exhibit JSG-2 and page 4 of that schedule -- I'm sorry -- page 5 of that schedule at the back, when you put the -- when you just look at the Zacks data, you'll see that companies with projected growth rates above 7 percent or 7 percent above include every single company there, except WGL Resources. So the 7 percent number is towards the middle of that range, of the range that I adopted, 6.75 to 7.75. There's one company that's below that range. Keyspan is just slightly above that range. Laclede's well above the range, but everybody else is grouped right in the middle. They're all in the 7 percent range. I thought that that was a pretty good anchor.

The retention growth I usually think of as

being a base amount that a company can achieve and usually under most circumstances you would expect it to be able to do better than that. And the analysts in this case thought that the company should do better than that, but if you look at the weighted average in the last column, you'll see that you have several companies a little under that range. And, let's see, Keyspan at 7.5 and Laclede at 9.4. So I used -- essentially, after considering other factors other than the simple two-thirds/one-third objective approach, I felt that 6.75 to 7.75 really reflected what investors expected and you can see that from the Zacks forecast where virtually all of my companies are 7 percent or higher.

Q. Okay. Looking at the top range of 7.75 percent, can you show me anywhere on pages 5, 6, and 7 of Schedule 2 where you have developed an average growth for the six companies that is as high as 7.75?

A. Now, the purpose of a range is to more or less put the company within some range around which you think on a normal basis these companies would be. The Zacks 7.6 percent obviously is well above the midpoint of that range. I was trying to establish about a 100 basis point range that would

be reflective overall of the group. So 7.6 would be well above the average in that range and the average for the weighted average would be toward the lower end of the range, but falls within the range.

So using those two numbers as anchors, you can go a little above 7.6 percent on the Zacks average earnings and get to 7.75. You can go a little below the 6.9 percent average and get to 6.75 and that gave me a 100 basis point range.

Q. Again, looking -- I'll repeat the question and please answer the question. Looking at the top of the range, 7.75 percent, can you show me anywhere on these pages, 5, 6, and 7, where you developed an average growth for the six companies that is as high as 7.75 percent? Just yes or no.

A. There's no simple average that does that, no.

Q. Okay. At lines 19 through 21 of page 21 you state that your range of 6.67 percent to 7.75 percent is consistent with the retention growth for the six companies. Please turn to page 5 of Schedule 2 and read to me the average retention growth for the six companies.

A. Would you take me back to the first citation that you had?

Q. Page 5.

A. You were citing someplace --

MR. HOBERG: Page 21.

Q. (MR. BINEK CONTINUING) Pages 19 through 21.

MR. HOBERG: Wasn't it line 19 through 21?

Q. (MR. BINEK CONTINUING) Lines 19 through 21 of page 21. The average retention growth rate for the six companies.

COMMISSIONER WEFALD: Does it start out "in my opinion," is that the line?

THE WITNESS: Okay. I see what you are asking. Page 21, the last three lines.

Q. (MR. BINEK CONTINUING) Starting at line 13 is the beginning of the paragraph.

A. But I believe you asked the question about the last sentence?

Q. Right.

A. And the last sentence says that, "This growth rate range is also consistent with the retention growth rates projected for these companies and their ability to grow by means other than retained earnings," which is what I was talking about earlier, that typically companies have the ability to grow by other means than retained

earnings and that allows them to generally achieve a slightly higher or somewhat higher growth rate than solely with book value growths.

You then asked me to turn to page 5 of Schedule 2 of Exhibit JSG-2 and reconcile the 5.5 percent average shown there with what I said on page 21. And the reconciliation is quite simply that it's -- if a company can have a base growth rate of about 5.5 percent, but investment analysts are projecting an average of 7.6 percent, it's consistent to think that 6.75 to 7.75 is consistent with the idea that book value forms sort of a base and the other methods that they can grow by, including investing in an unregulated operation, comes up with a higher rate of return.

Q. Over the long run how does a utility company do better than the retention growth?

A. There are several ways they can do that. One actually is contained in Mr. King's testimony. Mr. King has a growth rate component -- he calls it SV, issuing stock at above book value. If a company has some unregulated operations and those are doing reasonably well, it will have a book value -- or market value above book value and it's able to grow in that way. I believe Mr. King for his companies

estimated about 1 percent additional kicker to the growth rate from that. I'd have to go back and check his numbers, but it's something in that ballpark.

Another way that they can do that is by essentially borrowing to invest in new assets, that if those assets earn more than the cost of capital, it increases -- the market value of those assets exceed the book value and the company over time can generate retained earnings from these new unregulated assets and essentially build their equity ratio back up again and then repeat the process. And that's a very, very common thing, is that companies borrow because they find that they have a really good investment that will make them better off. They do so, they invest in it, and if it pays off well and it's making a 20-percent rate of return, and they borrowed the money at 8 percent, they get a big kick in their earnings per share. The stockholders get the difference between the 20 percent the operation makes and the 8 percent that they borrowed at.

So those are a few of the ways and I think those are probably the primary ways. I could probably think of a few others that are less

important, but those are big ones. And my 5.5 percent earnings retention growth rate, I should note, is a little bit different from Mr. King's book value growth rate in that I have not included the SV factor in the 5.5. I have assumed that the SV factor -- or actually I should call it a term because it's used as a term, it's an add-on to the retention growth rate -- is encompassed in the Zacks earnings forecast, which are higher, and that the other ways that a company can grow, including the SV term, are in the Zacks earnings growth estimate. So retention growth is sort of a baseline, but you can do all these other things. And clearly investors are expecting some of that to happen.

MR. HOBERG: Dr. Gaske, for the record, what is the SV factor?

THE WITNESS: It's the stock -- the percentage increases in the shares outstanding times the premium over book value that you are able to sell your stock at.

MR. HOBERG: Thank you.

THE WITNESS: And explained in fairly great detail in Mr. King's testimony.

(Exhibit 12 was marked for identification.)

Q. (MR. BINEK CONTINUING) I'd like to refer

you to page 23 of your testimony. On pages 6 through 8 you describe data by Ibbotson Associates on returns to stocks, bonds and treasury bills since 1926. I've handed you a response that Mr. King filed to MDU's September 6, 2002 data request, question 14. And this is marked as Exhibit 12.

Have you seen this response?

A. Yes, I have.

Q. In this response does Mr. King represent that he has supplied the yearly returns to an S&P composite index and S&P utility index, long-term corporate bonds and public utility bonds for every year from 1927 to 2001?

A. Yes.

MR. HOBERG: Isn't it 1928?

MR. BINEK: Or '28.

Q. (MR. BINEK CONTINUING) Now, would you look at the bottom of that sheet and identify what is reported on the last four lines?

A. A geometric mean return for the series and an arithmetic mean return for the series, a standard deviation, and a median.

Q. Are you familiar with those terms?

A. Yes, I am.

Q. Would you please describe your

understanding of the meaning of each of those terms?

A. The geometric mean tells you the average historical rate of return that occurred throughout the period, assuming compounding. And it's a very good indicator of your past historical return that you earned. The arithmetic mean is the average of the return earned each year, year by year. And it's a very good indicator of future expected return.

The standard deviation tells you how much variation there is in a particular series of numbers. And, in fact, what the standard deviation really tells you is that if you assume that the data have what is referred to in statistics as a normal distribution, it's a number that you can add to the mean, the arithmetic mean, plus or minus, to determine a range within which two-thirds of the observations fall or would be expected to fall. In this case I'm not entirely sure whether he had done this as a population mean or sample mean. Usually it's calculated as a sample mean, so I would presume that, but maybe we'd have to ask him which kind of mean he used or rather what kind of standard deviation he used.

And the last number, the median, is the number that half of the observations are above and

half are below.

Q. If the standard deviation is higher than the mean, what does that tell you about the statistical significance of the mean?

A. That there's a high probability that the mean of that particular series is zero, or at least -- let's say the standard deviation is exactly equal to the mean, then there's about a 16 percent chance that the real number would be zero or less.

Q. Please read the arithmetic means and the standard deviations of each of these series.

MR. HOBERG: I think we better have this thing offered first, Mr. Binek.

MR. BINEK: Oh, I'm sorry. I will offer.

MR. HOBERG: Any objection to Exhibit 12, Mr. Pearce?

MR. PEARCE: No. On the assumption that Mr. King prepared this from published data, I have no objection.

MR. HOBERG: Exhibit 12 is admitted. Mr. Binek, please.

Q. (MR. BINEK CONTINUING) Now, would you please read the arithmetic means and the standard deviations of each of these series?

A. 12.33 percent for the S&P composite, and

20.3 for the standard deviation. For the public utility index, 11.11 percent. And 22.65 percent for the standard deviation. The long-term corporate bonds, 6.06 percent, and the standard deviation, 8.76 percent. The public utility bonds, 5.79 percent. The standard deviation, 8.11 percent.

Q. If I buy a share in a company, what price do I pay, the market price of the share or the book value of the share?

A. You pay the market price.

Q. If the market price is twice the book value, I still have to pay the market price, don't I?

A. Yes, you do.

Q. If the company is earning 20 percent on its book value and I pay a market price twice that book value, what is my return?

A. I can't calculate that in my head.

Q. Would it be 10 percent?

A. If there's no growth. Yes, if the company paid out its dividend, everything they make.

Q. What, in general, do you believe to be the relationship between market price and book value of the average company in The Value Line Investment Survey that you cite on page 25 of your testimony?

A. It's quite above book value. I don't recall the composites at this time, but it's probably in the neighborhood of four or five.

Q. Please turn to page 9 of Schedule 2 of your Exhibit JSG-2. We keep going back to that sucker.

COMMISSIONER WEFALD: Would you repeat the number again, please?

MR. BINEK: It's JSG-2, Schedule 2, page 9.

THE WITNESS: Which page now? I'm sorry.

Q. (MR. BINEK CONTINUING) Page 9. There you show debt and equity -- are you there? I'm sorry.

A. Yes, I am.

Q. There you show debt and equity ratios of your six proxy companies. They are all quite close together except one. Which is that one?

A. Keyspan.

Q. Keyspan has an equity ratio of only 38.84 percent. What effect would that have on the financial risk of that company?

A. Other things being equal, that should raise what we referred to as the financial risk. And Keyspan, if you look at page 2 of the same schedule, has an A plus and an A2 bond rating, which gives you a good idea of how investors view the financial risk. It's pretty comparable. Actually, it's the

only one that's identical to the first mortgage bonds of Montana-Dakota -- or MDU Resources that are secured by the public utility assets. So Montana-Dakota -- Montana-Dakota's bonds and Keyspan bonds have virtually the same rating so that the overall risk, that at least bond investors are looking at, is pretty much identical between the two.

Q. On page 7 of Schedule 2, doesn't that show that Keyspan has the second highest DCF return of the six companies?

A. Yes.

Q. Do you think that the low equity ratio of Keyspan might have some influence on the equity risk perceived by investors?

A. Well, two things interrelate in the sense that you can't -- when you look at the return on equity, you have to look at both the business risk of the company and its financial risk. And the two, in a sense, multiply against each other. So undoubtedly part of their rate of return is based on their high financial risk or -- and part of it is based on business risk. When you combine the two things, you come up with an overall risk assessment and, as I said, the bond rating agencies look at Keyspan as a whole as being almost identical to the

Montana-Dakota public utility assets. But both of them are rated -- have bond ratings below the average for that group, so I'm not surprised that Keyspan is above the average. Montana-Dakota Utilities do have low average bond rates for this group.

Q. I'd like to have you turn to page 32. On page 32 you list your costs of capital indications. What is the distinction between investor requirement and cost of capital?

A. The investor requirement is the return investors require on the sunk investment that's there. The cost of capital is what they require in order to be able to track new capital on reasonable terms.

Q. If we ignore flotation costs, we would focus on the first column; is that correct?

A. Yes.

Q. Now, I'd like to concentrate on the second stage retention growth. The number we see there was developed on page 6 of Schedule 2 of your exhibit; is that correct?

A. That's correct, yes.

Q. The growth component of that number was developed on page 5 of Schedule 2; is that also

correct?

A. Yes.

Q. Isn't it true that the retention growth that you used is not all retention growth, but only one-third retention growth, the other two-thirds being Zacks forecast?

A. Right, that's why I referred to it as a second stage retention growth, or it's a weighted average of Zacks and retention.

Q. If we developed a DCF using solely retention growth, would it consist of a growth factor of 5.5 shown on page 4 of Schedule 2 and a dividend yield of 5.14 percent developed on page 3 of Schedule 2?

A. Mathematically that would be correct. It wouldn't mean anything because it wouldn't match up with investors' expectations.

Q. What would the DCF result be?

A. If you add 5.5 and 5.14, you get 10.64 and then, obviously, you would add the flotation cost adjustment.

Q. Okay. Thank you.

MR. BINEK: Can I take a moment, please?

MR. HOBERG: Yes.

(Exhibit 13 was marked for identification.)

COMMISSIONER WEFALD: What number is this exhibit?

MR. HOBERG: Exhibit 13.

Q. (MR. BINEK CONTINUING) Mr. Gaske, does this -- I've handed you what has been marked as Exhibit 13. Do you recognize that exhibit?

A. It appears to be an exhibit you showed me earlier this year. I'm not positive it's the same one, but it looks to be almost identical.

Q. And you see a reference of Exhibit 14 in the right-hand corner of that exhibit and below that a Docket No. 80 under case PU-399-01-186?

A. Yes, I do.

Q. Was that an MDU electric rate case?

A. Yes.

Q. And this was a document that was introduced in that case; is that correct?

A. Yes.

Q. Can you tell me what this document is?

A. It looks to be a survey of rates of return that have been authorized -- or requested and authorized in past rate proceedings. It also shows the dollar amount that the increase or decrease and other information about when these cases occurred.

Q. Okay. And would you agree that -- I'm

referring to the first page of this document in the introduction, that it says that the survey covers orders issued by state regulatory commissions during the period October 1, 2001 through September 30th, 2001; is that correct?

A. I'm sorry. I missed where you were referring.

Q. It's in the first paragraph, about the third or fourth line down, it says that -- it indicates the period covered by the report is October 1, 2000 through September 30th, 2001?

A. Yes.

Q. Okay. And what is the date of this report?

A. It's dated December 15th, 2001.

Q. And it says that it's an annual survey?

A. Yes.

Q. So would it be safe to assume that this is the latest annual survey that has been put out by Public Utilities Reports?

A. That I don't know.

Q. Just assuming an annual survey issued December 15th of 2001.

A. Yeah, I would assume so. I don't know if it's some kind of a mutant average or something like that.

Q. Okay. But there's no exact science to this exhibit as far as use of it, but I'd like to explain to you, if you would look at the following pages, I've highlighted several cases and if you will look at those cases, they are all ones that were decided in the year 2001. I would also like to point out that under North Dakota, Roman numeral VII, in red highlight or red marker is Otter Tail Power Company Gas at 12 percent ROE, and I would ask that all of the parties acknowledge the fact that Otter Tail Power Company does not have a gas distribution company operating in North Dakota and so this is obviously an error. It's just a carryover from their electric case and the same reference is to their electric case, is just a mistake that they made. There are not all that many cases here. I'd like to have you start with the first case.

MR. BINEK: Yes. I was just getting to that. I would like to offer Exhibit 13.

MR. HOBERG: Any objection, Mr. Pearce?

MR. PEARCE: No. It's hearsay, but probably pretty reliable hearsay, so I won't object.

MR. HOBERG: Exhibit 13 is admitted.

Q. (MR. BINEK CONTINUING) Now, I would ask, would you please go through the highlighted cases

and just indicate for us the company name, the order date and the newly authorized rate of return on company equity, starting with Arizona, first of all?

MR. HOBERG: You want him to read these into the record?

MR. BINEK: He can or --

MR. HOBERG: Can't the document speak for itself?

MR. BINEK: That's fine. I have no problem with that.

Q. (MR. BINEK CONTINUING) I would like to have you just kind of peruse these different entries, though, and then I would -- the question I would have for you is, if you would agree with me that the ROE range for the majority of these cases range from 10.7 percent to 11.5 percent?

MR. HOBERG: Do you need a couple minutes to look at that, Dr. Gaske, or a couple seconds?

THE WITNESS: I don't see any that are below 11.7 -- or I'm sorry. I don't see any that are below 10.7. I do see a couple that are 12.25 and 12.1 on the last page.

Q. (MR. BINEK CONTINUING) But my question is, would you agree that the majority of the cases range from 10.7 to 11.5?

A. Well, if you start at the very bottom of the range and count upwards until you get to a majority, that's probably true. If you start at the top and work your way down, you probably get another number.

Q. Okay. Well, would you agree with this statement, that the majority of them range from 11 to 11 and a half percent? If you can't agree, that's fine. The document does speak for itself.

A. I only see five back in that time period were above 11.5.

Q. Okay. And there were several below 11?

A. Yes.

Q. Okay. Would you also agree with me that, according to this report, the highest ROE given in 2001 that was included in the survey was 12.25 percent?

A. Yes.

Q. Would you agree that there have been relatively few gas rate cases reported so far in 2002, reported by Public Utility Reports, if you know?

A. I don't know.

Q. Okay. Are you familiar with a case entitled Re Yankee Gas Services Company, a case

decided by the Connecticut Department of Public Utility Control on January 30th, 2002 and reported at 215 PUR4th, 185?

A. No, I'm not.

MR. BINEK: At this point, I would just like to show a copy of the case. I don't believe it needs to be offered as an exhibit, unless MDU would like to have it as an exhibit. It just refers to the ROE in this particular case, and I would like to have Mr. Gaske look at it.

MR. PEARCE: Well, I certainly would object to it being offered as an exhibit. I don't think that the rate of return on a case last year in the Eastern Seaboard has any relevance whatsoever to the return and costs in this case. So it certainly isn't relevant to this proceeding.

MR. BINEK: The only purpose is to show what is happening from basically the end of 2001 in the PUR report, what is shown up in PUR since then, kind of showing a trend.

MR. PEARCE: Well, that's the issue. Why would that be relevant to this case?

MR. BINEK: I think it is relevant.

MR. HOBERG: Dr. Gaske said he's not familiar with that case. Is there a better witness

to offer this through?

MR. BINEK: No, I don't think so. It's a case that's been reported and it's not a big issue.

MR. HOBERG: Are you withdrawing?

MR. BINEK: Well, my first question is whether the Commission would like to have it offered as an exhibit? I have three cases. I'll offer them as exhibits and if that's the course you would like to pursue and, apparently, based on the objections that Mr. Pearce has indicated, that would be the way to go.

MR. HOBERG: Okay. So you have two more besides this one?

MR. BINEK: Two more cases, yes.

MR. HOBERG: Are they the same relevancy that you're proposing?

MR. BINEK: Right. They're different -- in different jurisdictions. They're cases that have been reported in the year 2002.

MR. HOBERG: Mr. Pearce?

MR. PEARCE: Well, I would object to any such case. I mean, if they're cases reported in some public forum, anybody can look at them, but they certainly have no relevance that I can see to the issues in this case.

MR. HOBERG: Why don't you state them, give us the cites of those on the record, please, Mr. Binek, and we can make them available on an official notice basis, if the Commission wishes to use them, if the Commission believes they're relevant.

MR. BINEK: That's fine with me.

MR. HOBERG: Give Mr. Pearce a copy and perhaps after he has a copy of those, he will be able to make some argument that the Commission shouldn't take official notice of those because they're not relevant. At this point in time, you know, I don't know what the Commission would do with those. Maybe nothing. So let's take official notice of those three and pass them out to the Commission as a possibility that the Commission may take official notice of those in actually making a decision.

MR. BINEK: Very good.

MR. HOBERG: Why don't you read each of them as you're passing them out, what the decision is?

MR. BINEK: The first case is entitled Re Yankee Gas Services Company. It's Docket No. 01-05-19PH01, decided by the Connecticut Department

of Public Utility Control on January 30, 2002. And that is reported in Public Utility Reports 215 PUR4th, 185.

The next case is Re Berkshire, B-e-r-k-s-h-i-r-e, Gas Company. It's Docket D.T.E. 01-56, decided by the Massachusetts Department of Telecommunications and Energy, on January 31, 2002. And pages are eliminated at the bottom. That case is in 215 PUR4th, that's P-U-R, 361.

And the last case is a short one. Re Atlanta Gas Light Company, Docket No. 14311-U, decided by the Georgia Public Service Commission on April 29th, 2002. And that is reported in 217 PUR4th, page 190.

MR. HOBERG: Mr. Binek, you're not offering these for any of the facts contained therein, just for the rulings in these matters?

MR. BINEK: The only purpose for these cases is to show the return on equity that has been authorized by these other public utility commissions.

MR. HOBERG: As part of their orders in those cases?

MR. BINEK: Pardon?

MR. HOBERG: As part of their orders in

those cases?

MR. BINEK: Yes.

MR. HOBERG: Mr. Pearce?

MR. PEARCE: Well, I just want to make sure that my objection stands as to any conceivable relevance of these. He is simply taking three decisions from other jurisdictions based on totally different facts and circumstances. I would hope the Commission would not -- I'm sure they do not simply come to their decision by copying the results from other unrelated cases, so I don't think it will have any undue influence, but certainly it has no conceivable bearing on this case. We don't even know if these are all the decisions from that year. Even if they were, they certainly wouldn't be relevant.

MR. HOBERG: Thank you, Mr. Pearce.

Okay. Mr. Binek, do you have any further questions of Dr. Gaske?

Q. (MR. BINEK CONTINUING) I'd like to focus on some areas where you apparently agree with Mr. King. And this basically is in your rebuttal testimony, I believe.

MR. BINEK: That testimony hasn't been marked yet, has it?

MR. PEARCE: I didn't realize you were asking from rebuttal testimony. That isn't in the record, so we have to wait.

MR. BINEK: Okay. We'll wait. We'll cover it afterwards.

MR. HOBERG: You're bringing Dr. Gaske back on as rebuttal?

MR. PEARCE: Yes.

MR. BINEK: Okay. In the past we've kind of run these altogether. So that's fine. We'll cover him after he gives his rebuttal.

MR. HOBERG: I think that will be better. It will follow more clearly.

MR. BINEK: I have no further questions then.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, did you have any questions of Dr. Gaske?

COMMISSIONER REINBOLD: Not at this time. Thank you.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

COMMISSIONER WEFALD: None at this time, either.

MR. HOBERG: Thank you. Commissioner

Clark, please.

COMMISSIONER CLARK: I did have a couple.

EXAMINATION

BY COMMISSIONER CLARK:

Q. On page 28 of your testimony --

COMMISSIONER REINBOLD: What page?

COMMISSIONER CLARK: Page 28, lines 18 and 19.

Q. (COMMISSIONER CLARK CONTINUING) In this section you are discussing some of the business risks that you feel are faced by MDU.

A. Yes.

Q. You make a statement -- this follows up on previous testimony earlier this morning talking about the direct competition from propane heating oil. I think coal was used as another example of competition that MDU faces. Wouldn't raising rates be a strange action in response to direct competition?

A. Definitely not, under the circumstances. If you have direct competition, you will lose business, if it's really powerful direct competition. Currently, Montana-Dakota is able to maintain its business. If it has to maintain its rates at a level that it can't recover its costs, it

actually should try to go out of business and let the competitors have the business. So in a very short- run context, usually in markets you see that if there's a lot of competition, people are forced to lower their rates and the one who lowers his rates far enough that he can't recover his costs anymore, he goes out of business.

In Montana-Dakota's case I don't think that the competition at this point in time is so severe that they would go out of business, but if they were not allowed by this Commission to charge rates that would recover their costs, they should think about getting out of the business. Just as in a competitive market, if competition is the regulator that forces the rates to be below cost, a competitive company would after some time exit the market.

Q. Well, I'm asking because it seems counterintuitive that if you're facing competition and you've got potentially some customers who are on the edge, could potentially switch to another, in this case, heating source, that an increase in the rates would cause potentially some of those customers to switch over, and wouldn't that in the end, in fact, just increase the risk that MDU faces?

Wouldn't the better response be to find savings somewhere else, if you are, in fact, facing that competition?

A. Well, I think as Mr. Fox testified earlier, they have tried to find as many savings as possible. What really happens with natural gas is that the cost of the commodity drives the attractiveness to a great deal -- great extent, also. So that's probably a bigger problem for Montana-Dakota in terms of whether they increase the distribution charge by 4 percent or whether the suppliers to the company, whether the natural gas markets are selling gas at $2 or whether it's at $4. That's where they really have to be concerned about such competition. And right now they can compete. If the price of natural gas is driven upwards in the $4- and $5-range, you may see people shutting off their gas service at a fairly rapid rate.

Q. Another question on that same page, talking about kind of the general business climate and risks that MDU faces. On lines 10 through 12 there's a sentence there, On a practical level, MDU's relatively small natural gas distribution operations are heavily dependent on a relatively undiversified local economy.

Could you just expound on that a little bit?

A. Well, you have in their service territory some mining operations, refining operations, a lot of farming and farming-related operations, and they face some risk that some of these kind of operations, manufacturing-type things -- I shouldn't call it manufacturing, but processing foods and things like that, could shut down and they'd lose that business, but, to my mind, a much bigger risk for them is the fact that if operations like that shut down around here, the people who work at those plants and local economies will suffer and people will migrate out of the towns and Montana-Dakota will be sitting there with gas distribution mains in place and yet because of, you know, events in the local economy, they're at risk.

And people who serve larger cities have a much smaller risk in that regard. Most large cities have many, many different kinds of businesses and industries that support the population and when one leaves, usually others are able to expand to take up the slack. I don't see that in the towns that Montana-Dakota serves.

Q. I guess I've -- the reason I ask is, I've

always heard that North Dakota's economy, which would be true of economies of states like ours, is typically more resistant to booms and peaks and valleys. That, in fact, larger states more kind of dynamic economies are much more likely to have the peaks and valleys. And that's what we've seen certainly in this latest recession. We seem to be a little bit more recession proof. We seem to be a little bit less prone to the booms when times are good as well.

How does that fit with the comments in there?

A. As far as short-run booms and busts, I think you probably are pretty insulated from that because of a lot of agricultural-related things, but agriculture booms and busts a little bit. To the extent more energy production occurs in the state, you'll probably be more subject to booms and busts in the energy business.

On a longer-term basis, and Montana-Dakota has to think about longer-term basis, their plant is there for many, many years. They put it in and it will stay there for 30 years or something like that. As businesses shut down and people migrate out of towns, or just the natural change of people's desire

to, say, move to the big cities or whatnot, they can leave the towns, but Montana-Dakota's facilities are still there. They still have to try to recover their costs. To the extent you get some major employers that shut down for whatever reason, it's not a guarantee that the people will stay here or that the people will be able to pay their bills or things like that.

So even if you're resistant to short run year-to-year fluctuations in boom and bust cycles or even on two- or three-year cycles, on a longer run cycle, which really is very important to MDU because it has a lot of fixed costs, they have to worry about the big employers in this area, will they shut down and really dramatically change the economics of their business.

COMMISSIONER CLARK: That's all I have right now. Thank you.

MR. HOBERG: Thank you, Commissioner Clark.

Mr. Pearce, any further questions of Dr. Gaske?

MR. PEARCE: Just one short question, really.

REDIRECT EXAMINATION

BY MR. PEARCE:

Q. Dr. Gaske, there was some discussion on your cross-examination about Exhibit 13, which was a PUR report of decisions ending at a point in 2001. Would it surprise you that the cost of equity capital that you derived for Montana-Dakota for the 2003 projected year would be different from and perhaps more than any of the cases which the last report here seems to end in June of 2001 in this Exhibit 13?

A. No. No. In the last year the stock market has gone down considerably in general. Investors' risk aversions have increased and we've seen some fairly remarkable things happen in the financial markets and not all of them very good for investors.

Q. And the cost of capital is essentially unique to each entity, isn't it, depending on the circumstances and the business and the risk, and so on?

A. Yes.

MR. PEARCE: I have nothing else.

MR. HOBERG: Thank you, Mr. Pearce.

Mr. Binek, anything further of Dr. Gaske?

MR. BINEK: No.

MR. HOBERG: Thank you. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. I just have a question about this risk aversion factor. I can only relate it to my own experiences in the market and --

A. I hope they've been good.

Q. Haven't -- just describe for me this risk aversion factor.

A. Well, one of the things that has happened quite a bit during the last year is that people have been selling off stocks or they really don't want to own common stocks. And they are trying to own short-term investments, things like U.S. Treasury bills, or cash or CDs even though -- and as a result of that, they have driven the short-term interest rates way down. They want to get out of stocks. They want to put their money in the safest place that they can.

And what happens there is that the interest rates on your CD at the bank and/or U.S. Treasury bills or even U.S. Treasury bonds have gone way down. Whereas, in my opinion, the required return on things like common equities has gone way up.

People just don't want to be in equities right now.

Q. That's the part I don't understand. Why would that go up? Why would it just be a certain amount greater than what you can get on a short-term money note, let's say? I mean, I don't understand your conclusion that that would go way up, if I'm only able to return -- get a return of a very small amount on a very short-term equity. Why wouldn't I be pleased if it was 5 percent more, and I could know that it's going to be even 5 percent more, let's say 8 percent rather than 3 percent, or I guess even right now many times in money market it's 1 percent? So why wouldn't I be pleased if I could get 6 percent?

A. The overall return might go up or it might go down some that you require on your common equities, but they won't go down nearly as much as on safer investments. But investors view the market as very risky. If you say -- you think of it in terms of a common equity has five units more risk than a bond, if the market is very risky, that extra five units of risk will be very valuable. If people are very uncertain about the market, they don't -- they're going to want a very high return to take the five units of extra risk.

If the economy is doing very well, things are very stable and people are very confident about the future, the price of risk, what they're willing to spend for -- or what they require for that extra five units of risk will be much lower. So you ask, you know, why don't they want 5 percent more than what they can get on bonds? Over time what they require will go up, the extra amount they require will go up and down. Right now we're in a period where people don't want to own common stocks. They think they're too risky and they do want to own bonds and short-term government bonds and short-term debt.

So the extra units of risk, let's say the five extra units of risk, those become very valuable or very expensive, they just aren't going to buy unless they think they are going to get a very good premium over what they can get on the bonds. So the premiums go up and down over time.

COMMISSIONER WEFALD: Thank you for that analysis.

THE WITNESS: Hopefully, your experiences have been better than mine in the market, but it has been a risky year or a very discouraging year.

MR. HOBERG: Thank you. Commissioner

Clark.

FURTHER EXAMINATION

BY COMMISSIONER CLARK:

Q. I do have a question on that. Is it that investors want to get out of the stock market, period, or does it require maybe a little bit more granular analysis, and that is that certain sectors are just horrendous? For instance, telecom is one of them. Fortunately, we can't invest in the telecom market because we are prevented by state law from doing that. Are certain stocks more attractive because of that, for example, potentially kind of old-fashioned utility companies that are regulated?

A. The utility companies are probably more attractive, much more attractive now than, say, a telecom stock. A lot of people wanted to buy telecom stocks two years ago. But relative to bonds, utilities are less attractive, so the premium that people require on utilities is, I think, higher now and has gone up over the last year. So some people selling telecom will buy utilities. Some people who have utilities will sell the utilities and buy bonds. But if you look at bonds versus utilities, I think that spread is increased. Utilities versus telecom, that spread has really

increased. Nobody wants the telecom stock right now. So all across the board, from the very safest to the very riskiest investment, I think everything is spread out.

Q. Would it follow then when the stock market get on a roll like it did for the past 10 years or so prior to the last few we've had, that utility regulated ROEs should go down then because it's easier to attract capital?

A. The spreads over bond yields should go down, but you can have a very good market, but the interest rates are very high. You can -- so it really depends on a lot more factors.

Q. I'm just wondering if then the argument would be, well, all the peer companies are doing so well, we need to increase our rate of return now to attract capital vis-a-vis the rest of the market?

A. Well, that one depends on -- yeah, how much the individual companies are willing to invest. But it really is a good question about -- people are afraid to invest in almost anything. So the measure, at least that I try to look at is, what kind of spread versus the bond yield, because those are much easier to determine than the equity returns.

COMMISSIONER CLARK: That's all I have. Thanks.

MR. HOBERG: Thank you. Any further questions of Dr. Gaske? Thank you, Dr. Gaske. Take an hour recess here, luncheon recess?

COMMISSIONER WEFALD: Can you tell me, please, the order of witnesses that are going to be followed for this average?

MR. HOBERG: I believe they're in exactly the same order as listed in the direct testimony, is that correct, Mr. Pearce?

MR. PEARCE: Yes, it is.

COMMISSIONER WEFALD: And then we'll go through and then the rebuttal will happen in the same order by those people following?

MR. HOBERG: Then it will be Mr. Binek's presentation of his witnesses after the direct of MDU and then followed by the rebuttal.

COMMISSIONER WEFALD: That's a little unusual, but -- because then what happens you have -- well --

MR. HOBERG: I don't think it's unusual. I think that's the practice we followed in the past.

COMMISSIONER WEFALD: But the thing is, there's a lot of information that has been agreed

upon by the parties by the time we get to the rebuttal. So we're going to have to cover things that perhaps aren't that important because the case -- they have agreed on a bunch of things as they have gone along.

MR. HOBERG: Well, I would assume those things we've agreed upon you're not going to be spending much time on, correct?

MR. PEARCE: No. The rebuttal only touches on points on which there's disagreement still. So the rebuttal -- anything that's been agreed to won't be testified to on rebuttal.

COMMISSIONER WEFALD: Okay.

MR. HOBERG: Is that the order you expected, Mr. Binek?

MR. BINEK: Well, we have done both ways where we've gone with questioning on both the direct and rebuttal testimony initially, and that was what -- kind of the mode I was in. It doesn't matter to me which way we do it, and this seems to be set up to do it the long way.

MR. HOBERG: The long way? I don't know that it's necessarily longer, as long as the parties understand that things that, you know, there's no disagreement about, you don't have to spend any time

on really.

MR. BINEK: Hopefully, it will work out that way.

MR. HOBERG: I think it's sort of six of one and half-dozen of the other, unless you --

MR. BINEK: It's fine to do it that way.

MR. HOBERG: Perhaps we'll reflect on that over the break.

MR. PEARCE: It seemed like it was the usual judicial procedure; plaintiff, defendant, and then plaintiff's redirect, is really the mode we are following, I think.

MR. HOBERG: That's what I thought, too. All right. Let's take a one-hour lunch.

(Lunch recess was taken.)

MR. HOBERG: Okay. We're back on the record after a luncheon recess. And just to kind of rehash maybe the concerns about the procedure today in regard to direct and rebuttal, I think everybody is basically pulling in the same direction and maybe to provide a little bit of consistency and some guidance, it seems like except for perhaps the first witness, Mr. Fox, who you wanted to highlight the direct especially, you're offering the direct, but you're not really asking many questions.

MR. PEARCE: Right.

MR. HOBERG: And maybe that will be the procedure for the whole rest of the direct. It can go relatively quickly, except for the PSC's case, but if you do really have -- if your questions are more along the lines of something for the rebuttal, perhaps you should save them for that, but there may be some questions to highlight or to ask something that somebody neglected to cover in the rebuttal, but, basically, I think the direct should go relatively quickly, at least for MDU's case, and the rebuttal will be where more of the questions are, but I think we'll get to the same place we would have if we had just forgot about the direct and went right to the rebuttal. I think that was a time where there was pretty much agreement in another case where we could just move right to the rebuttal, but that isn't the situation here, as I read it, anyway.

So we'll proceed with the direct and then perhaps move relatively quickly to the rebuttal, except for perhaps Mr. Binek's case. Is that clear? I maybe didn't make it very clear. I hope I did.

Mr. Pearce, do you want to proceed, please?

MR. PEARCE: Yes. I'll call Craig Keller.

MR. HOBERG: Mr. Keller, were you here earlier when I gave the admonition in regard to perjury?

THE WITNESS: Yes.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: Yes, I do.

MR. HOBERG: Thank you. Mr. Pearce, please.

CRAIG A. KELLER,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Keller, in connection with this case have you prepared or had prepared under your direction and control direct testimony of Craig A. Keller, CPA?

A. Yes, I have.

Q. And if I were to ask you the questions that are in that prepared, prefiled testimony today, would your answers be the same as appear in there?

A. Yes, they would be.

Q. And to the best of your information and

belief, all of your answers contain accurate and correct information?

A. Yes, they do.

MR. PEARCE: I will offer the direct testimony of Mr. Keller. I think it would be Exhibit 14.

MR. HOBERG: Exhibit 5.

MR. PEARCE: I'm sorry. Exhibit 5. I have no further direct questions.

MR. HOBERG: Thank you, Mr. Pearce. Any objections to Exhibit 5?

MR. BINEK: No.

MR. HOBERG: Exhibit 5 is admitted.

Mr. Binek, do you have any questions of Mr. Keller on direct?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Keller, would you please turn to your Statement A?

COMMISSIONER WEFALD: Where do we find that?

MR. PEARCE: Exhibit 2.

MR. HOBERG: There's a document entitled Statements A through O. Is that what you're

referring to, Mr. Binek?

MR. BINEK: Yes.

COMMISSIONER WEFALD: And this is Statement F?

MR. BINEK: Statement A.

Q. (MR. BINEK CONTINUING) The first two pages of Statement A present a balance sheet that is labeled MDU Utilities Co. The remaining 27 pages are of notes on the balance sheet; is that correct?

A. Yes.

Q. Those 27 pages are not headed MDU Utilities Co., but rather MDU Resources, Inc.; is that correct? Am I correct that the notes pertain to a different balance sheet than Statement A?

A. I believe the balance sheet is the -- the balance sheet of Montana-Dakota is not the consolidated balance sheet, whereas the statements would be the consolidated -- the statements that are in our consolidated balance sheet of MDU Resources Group.

Q. Do all the notes on pages 3 through 27 apply as well to the first two pages of Statement A?

A. They would apply to the Statement A They may also apply to -- there will be information that will apply to some of the subsidiaries of MDU

Resources Group as well.

(Exhibit 14 was marked for identification.)

MR. BINEK: This will be Exhibit 14.

Q. (MR. BINEK CONTINUING) Now, I've handed you a document that's been marked as Exhibit 14. Can you identify that exhibit?

A. It says $150 million secured medium-term notes, MDU Resources Group, Inc.

Q. I'm sorry. Could you speak up a little bit?

A. It's the prospectus for $150 million secured medium-term notes, MDU Resources Group, Inc.

Q. Okay. And does this prospectus cover the $133.5 million in long-term debt that you list on page 1 of Statement F?

A. I believe it applies to a portion of that. I don't believe it applies to the entire. It would apply to the debt that was issued under this prospectus or under this here arrangement, financial instrument.

Q. Could you repeat your answer?

A. I said I believe it applies to the debt on this schedule of the $133 million that was issued under this financing instrument. So there is -- I believe there's also some debt that we have

outstanding that was not issued as part of this here prospectus here.

MR. BINEK: Okay. At this time I would offer Exhibit 14.

MR. HOBERG: Any objection to Exhibit 14?

MR. PEARCE: No.

MR. HOBERG: Exhibit 14 is admitted.

Q. (MR. BINEK CONTINUING) Who issued this prospectus?

A. MDU Resources Group, Inc.

Q. I'd like to have you turn to page 2 of the prospectus under the section titled "The Company." What company is described there?

A. It refers to the company as being MDU Resources Group, Inc.

Q. Does the company that -- the term "the company" include all subsidiaries under Centennial Energy Holdings?

A. I do not believe so. This states it's for the company's first mortgage bonds that are -- would be issued under our mortgage indenture, so that would apply only to MDU Resources and Montana-Dakota Utilities. It's on the first page, the very front of the prospectus, if you look on the very front of the prospectus. If you read the very first

sentence, it says, MDU Resources Group intends from time to time to offer up to $150 million aggregate principal amount of its secured medium-term notes as an additional series of the Company's first mortgage bonds having maturities ranging from 9 months to 35 years.

The only company that's able to issue notes under our mortgage indenture is Montana-Dakota Utilities or the utility.

Q. Lower down on that page of this, and I'm referring to page 3 now, is a section titled "Use of Proceeds." Would you please read that section?

A. "Unless otherwise set forth in a prospectus supplement, the net proceeds from the sale of the notes will be used to retire certain of the company's outstanding senior securities, including the refunding of outstanding first mortgage bonds, and for other general corporate purposes."

Q. Where in that section is there any specific reference to MDU Utilities Company or MDU Utilities Co.?

A. It doesn't state anything in this right here.

Q. Were those retired senior notes issued in the name of MDU Utilities Company or in the name of

the parent company, MDU Resources?

A. Well, they are one and the same. MDU is not a separate -- Montana-Dakota is not a separate corporation. So I believe all our debt is issued in the name of our legal entity, which would be MDU Resources Group, Inc.

Q. Where in this prospectus do we find a statement that the proceeds from the sale will be used only for MDU Utilities Company?

A. Well, I believe when it's saying -- refers to the company, it's talking about the company, MDU Resources Group, which is that legal entity only, and I think if we go down here --

MR. PEARCE: Could I just ask that we be careful for the record. I mean, there is no MDU Utilities Company. It's Montana-Dakota Utilities Company or MDU Resources Group, and I think we may be getting confused if we keep referring to MDU Utilities Company, which doesn't exist.

MR. HOBERG: Thank you, Mr. Pearce.

THE WITNESS: I guess when it refers to the company, it's talking about the legal entity, MDU Resources Group, and that is the same as Montana-Dakota. They're one legal entity. So when it refers to that, you know, I believe what it's

stating is that it is for the company, Montana-Dakota, MDU Resources Group, which is the same legal entity.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, do you have any questions?

COMMISSIONER REINBOLD: No.

MR. HOBERG: Thank you. Commissioner Wefald?

COMMISSIONER WEFALD: I have none.

MR. HOBERG: Thank you. Commissioner Clark?

COMMISSIONER CLARK: None at this time. Thank you.

MR. HOBERG: Mr. Pearce, do you have any further questions of Mr. Keller?

MR. PEARCE: No.

MR. HOBERG: Thank you, Mr. Keller. Mr. Keller, do you have the exhibit that was handed to you that was marked? Thanks.

Your next witness, please, Mr. Pearce.

MR. PEARCE: I'll call Rita A. Mulkern.

MR. HOBERG: Ms. Mulkern, did you hear the admonition I gave earlier in regard to perjury?

THE WITNESS: Yes, I did.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Mr. Pearce, please.

RITA A. MULKERN,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Ms. Mulkern, did you prepare direct testimony and have it prefiled in this case?

A. Yes, I did.

Q. And if I were to ask you the same questions today, would your responses be the same as in that prefiled testimony?

A. Yes, they would.

Q. If you will look at Exhibit 6, I believe it would be, is that your prefiled testimony?

A. Yes, it is.

Q. And to the best of your information and belief, is the information contained in that exhibit true and correct?

A. Yes, it is.

MR. PEARCE: I will offer Exhibit 6 at this time, and I have no further questions.

MR. HOBERG: Any objection to Exhibit 6?

MR. BINEK: No.

MR. HOBERG: Exhibit 6 is admitted. Thank you, Mr. Pearce. Mr. Binek, did you have any questions of Ms. Mulkern?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Ms. Mulkern, where in your filings can we find the northeast Bismarck expansion costs for 2003?

A. The northeast Bismarck expansion was included in the capital or the plant additions for 2003. The details of that were provided in data request responses.

Q. Are these costs included in the rate base?

A. Yes, they are.

Q. Are they included in depreciation?

A. The depreciation, yes, they would be.

Q. Are they included in operating and maintenance expense?

A. The ongoing, essentially, yes.

Q. Are they included in the high rate of

return?

A. I guess I really can't answer that one.

Q. Okay. I'd like to now have you turn to Statement I, page 2 of 6.

MR. HOBERG: Exhibit 2, the blue book here.

Q. (MR. BINEK CONTINUING) Do you have it?

A. Yes, I do.

Q. Would you please read that paragraph for the record?

A. "See pages 3 through 5 for Montana-Dakota depreciation rates as set forth in a study performed by Stone & Webster Management Consultants, Inc., as of December 31, 1992 for gas and common plant. See page 6 for internally developed rates as of December 31, 2001 for computer equipment and network equipment."

Q. Now would you please turn to page 5 of Statement I?

A. (Witness complies.)

Q. Did your internal studies result in substantial increases to certain depreciation rates?

A. Excuse me. Could you clarify that?

Q. Well, you listed depreciation rates there. Did these internal studies that you've performed result in any substantial increases to any of those

depreciation rates?

A. I believe that these accounts were ones that were not included in the Stone & Webster study and that's why they were developed internally. So they have not changed.

Q. Okay. I'd like to have you turn to page 4 of 6. Is that the Stone & Webster study?

A. Yes, it is.

Q. Is there an account 391 on that page?

A. There is an account 391, office furniture and equipment.

Q. Is that where computer equipment is supposed to be?

A. No. Computer equipment is contained in various subaccounts under the 391. That account would be just for office furniture and equipment.

Q. Did you do a complete depreciation study as of December 31, 2001 or only a piecemeal study of general and common plant?

A. Can you repeat the question again?

Q. Did you do a complete depreciation study as of December 31, 2001, or did you only do a piecemeal study of general and common plant?

A. We did not do a depreciation study as of December 2001, and these depreciation rates set

forth on page 6 were not done either at December 2001.

Q. I refer you back to page 2 of 6. Your last sentence says, "See page 6 for internally developed rates as of December 31, 2001 for computer equipment and network equipment."

A. That means those are the rates in effect as of December 31, 2001, not that they were developed based on December 31, 2001.

Q. When were they developed?

A. I don't recall the exact date that they were done. They were included or used in the last rate case.

Q. The last rate case for the gas utility?

A. Yes, the last rate case for the gas utility.

MR. BINEK: No further questions.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, do you have any questions of Ms. Mulkern?

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. Ms. Mulkern, how long have you been at MDU? I missed that. How long have you been with them?

A. I started with MDU in 1981.

Q. Okay. In your work with MDU have you testified in other cases before the PSC?

A. I have testified before this Commission and Commissions in Montana and South Dakota and Wyoming.

Q. Okay. I was going to ask about the other states, but you answered before I asked.

COMMISSIONER REINBOLD: I have no further questions. Thank you.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. Ms. Mulkern, I'm going to ask you the questions I had asked Mr. Fox because I've been referred to you for those questions. And so I asked him, each 1 percent of each -- I have to get out my notes before me.

Each 1 percent of the rates of return, how many dollars does that represent? So, for example, on Exhibit No. 10 where it showed that MDU Gas, let's say in the year 2000, had 11.12 percent and then it dropped in the year 2001 to 1.6 percent, what does each one percent represent, how many dollars?

MR. HOBERG: Do you have Exhibit 10?

THE WITNESS: No, I don't.

Q. (COMMISSIONER WEFALD CONTINUING) It probably is a different dollar number each year.

A. Yes, I guess in -- I guess to try to clarify, in 2001 we had a rate of return on equity of 1.6 percent. And we're saying in 2003 we're going to need $2.84 million. So, basically, to bring us up from 1.6 up to a 13.25, we would need 2.8 million. That's approximate.

Q. The 1.6 return on equity is in the year 2001. And the 13.25, you would like that in the year 2002?

A. The 13.25 is the equity return that we have requested in this case for 2003.

Q. Yes. So did you say that it would take 2.8 million to bring you that number in 2003?

A. That's right.

Q. So what would it take to bring you to that number in 2002? Is it a different number?

A. Yes. I can give you that. It would take $2.2 million to bring -- for 2002 to achieve a 13.25 percent return on equity.

Q. Okay. Thank you. Then you had answered a question from Mr. Binek, but I needed you to show me where that information can be found. The expansion

into north Bismarck, how the costs were recovered from expansion, are they included in your costs for 2002 when you anticipate the rate of return to be zero or the return on equity to be zero?

A. The costs for the northeast Bismarck expansion are -- in the rate case are the same costs as for any other new customer. The customers in northeast Bismarck will be paying a contribution for any costs over the extension policy, and according to that, they would give a contribution. So the costs in the case are the same as for any other new customer. And, also, the volumes associated with those new customers are also included in the case. Did I not answer your question?

Q. So you gave a dollar figure earlier to how much money. You said something had been returned in discovery. Can you just share that with me, because I haven't seen those discovery?

A. It's included in the discovery response dated July 25, and it is response No. 2.

Q. And do we have that in the materials that have been shared with the Commission?

A. We provided copies to the Commission.

Q. Where would I find that?

MR. HOBERG: Mr. Binek, do you have copies

of those data responses?

MR. BINEK: We should have copies of them.

Q. (COMMISSIONER WEFALD CONTINUING) But I wondered whether they had been provided to the Commissioners as part of your case.

A. They were not part of the case that was filed initially, but they were provided as -- detail provided as a data request. We did give a copy -- sent a copy, I believe, to the Commission.

Q. All right. So I would go back into the record for that.

MR. BINEK: Those are not a part of the record, Commissioner. Data requests are not a part of the record.

COMMISSIONER WEFALD: She told me she sent a copy to the Commission so I'm assuming she sent a copy to us. Is that wrong?

MR. BINEK: To the Commission staff.

COMMISSIONER WEFALD: Then we don't see that.

Q. (COMMISSIONER WEFALD CONTINUING) So I'm asking, is that information confidential, or is it available to the Commissioners?

A. It's available to the Commissioners.

Q. Where would I find it?

A. If someone could provide a copy of the data request response.

MR. HOBERG: Well, you have all of those, Mr. Binek. Do you make those available to the Commissioners?

MR. BINEK: We can make those available to the Commissioners. The consultant -- they were data requests that were made by the consultants.

COMMISSIONER WEFALD: I would like to see it, just that one.

MR. HOBERG: Just the one.

MR. BINEK: Pat said he could find it. Do you want that to be an exhibit in the record, or what?

COMMISSIONER WEFALD: I would prefer if Ms. Mulkern can just tell me the answer, but she's referring me to this exhibit, to this data request, so I would just like to have the information.

MR. HOBERG: Ms. Mulkern, do you recall the question? Can you give the response without looking at the exhibit?

THE WITNESS: If someone would provide me with a copy of the data request responses, I can do that.

MR. HOBERG: Okay.

THE WITNESS: It's been a while. Can you repeat the question?

Q. (COMMISSIONER WEFALD CONTINUING) Thank you. I just wondered, the 500 -- you mentioned a figure and I don't know exactly what it was. You mentioned a figure for the cost for the expansion in north Bismarck.

A. Okay. I think what you might be referring to earlier is Mr. Fox was talking about the service lines, where the company will own the service lines, and that he gave a figure of $500,000 and that was for the total company. For North Dakota for owning the service lines, it's going to be about $184,000. For the Bismarck expansion project we have about $120,000 in for 2002 and about $150,000 in for 2003.

COMMISSIONER WEFALD: Okay. Thank you. That's all my questions.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

EXAMINATION

BY COMMISSIONER CLARK:

Q. Looking at that Exhibit 10, which is Mike Diller's memo to the Commission, what was the reason for -- what was the difference in 2001 compared with '98, '99, 2000 that drove the ROE down 10 percent?

A. There were various reasons. One of the main ones was the operation and maintenance expenses.

Q. That would account for how much of that?

A. About $770,000, or the difference in increase in operation maintenance expenses from 2000 to 2001.

COMMISSIONER WEFALD: Are you referring to a specific statement?

THE WITNESS: Not one that is included in the filing.

Q. (COMMISSIONER CLARK CONTINUING) So $770,000 out of -- what would the total be?

A. That was the increase from --

Q. So that would account -- 770,000 would increase the rest. Out of how much of an increase in expenses?

A. Out of 12.2 million.

Q. Okay. So we've got a ways to go there. What's some of the other?

A. Others would be --

Q. I'm just trying to get at what was, you know, so different about that year as opposed to the other years previous to it, the other three years previous.

A. There would be a difference in sales volumes between the two years that would have contributed, and then some of the other reasons we've given in the case that we filed, increases in depreciation and taxes other than income.

Q. Is there, you know, like one document that I can go to somewhere in the testimony or the file exhibits that's going to kind of break that down for me real easily?

A. One place you can look is in the annual report to the Commission that we file. There is a comparison in that report each year comparing to the previous year, so if you look in the report for 2001 there will be a comparison to the year 2002 in there.

Q. Let's go to the 770,000 for operating and maintenance. Could you break that down a little for me?

A. One of the increases would be, of course, due to labor expense.

COMMISSIONER CLARK: Maybe I should do this: Will Ms. Mulkern be available later on after staff?

Q. (COMMISSIONER CLARK CONTINUING) I assume you'll be part of the rebuttal.

A. Yes, I will.

COMMISSIONER CLARK: Okay. Maybe it would be better to delve into some of this more in-depth stuff later on after the staff case and during rebuttal. We can hone in on some of this stuff more specifically.

MR. HOBERG: Any further questions?

COMMISSIONER CLARK: No.

MR. HOBERG: Any further questions by the Commission of Ms. Mulkern? Mr. Pearce, any further questions?

MR. PEARCE: No.

MR. HOBERG: Mr. Diller?

EXAMINATION

BY MR. DILLER:

Q. I'm going to have to help the Commission in the end and to make sense of all this I want to make sure I understand your answer, Rita. You've mentioned a couple of numbers, 184,000 for the cost of the policy change, is that revenue requirements, rate base expense? What is that number?

A. That is the capital investment in plant for service lines.

Q. Just the capital investment. Is it the same answer for the expansion costs, that that's

rate base then?

A. That's right. That's also the capital addition for the plant.

MR. DILLER: Okay. Thank you.

MR. HOBERG: Thank you, Mr. Diller. Anything further then of Ms. Mulkern at this time? Thank you, Ms. Mulkern.

Mr. Pearce, witness No. 7.

MR. PEARCE: I'll call Richard Espeland.

MR. HOBERG: I guess it's not witness 7. Exhibit 7 is his testimony. Witness 5.

Mr. Espeland, did you hear the admonition I gave earlier in regard to perjury?

THE WITNESS: Yes, I did.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: Yes, I do.

MR. HOBERG: Mr. Pearce, please.

RICHARD A. ESPELAND,

having been first duly sworn, was examined and testified as follows:

THE WITNESS: If I don't speak up loud enough, please tell me to try and force it out a little bit more.

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Espeland, in the course of this case, did you prepare and have filed with the Commission direct testimony of Richard A. Espeland?

A. Yes, I did.

Q. Okay. And looking at Exhibit 7, if you will, is that the same testimony from you that was prefiled?

A. That's correct.

Q. And if I were to ask you the same questions, would you give the same answers today?

A. Yes, I would.

Q. And to the best of your information and belief, is all the information contained in your testimony true and correct?

A. It is correct.

MR. PEARCE: I'll offer Exhibit 7. At this time I have no questions.

MR. HOBERG: Any objection to Exhibit 7?

MR. BINEK: No.

MR. HOBERG: Exhibit 7 is admitted. Thank you, Mr. Pearce.

Mr. Binek, do you have any questions of Mr. Espeland?

MR. BINEK: Yes, I do have some questions.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Espeland, you will agree that the costs of this plan have never been included in rates in North Dakota, wouldn't you?

A. That's correct.

Q. Why do you contend that the cost should now be borne by ratepayers?

A. When the program was implemented in 1982, it was not as common as they are today. It was more of a visionary plan. And today it's extremely common practice for these type of supplemental retirement plans to be in place. And it's appropriate for them to be in the rate base because it's part of doing business for those types of positions, as part of their total compensation program when you look at all of their compensation and benefits.

Q. Are you saying or suggesting that MDU's shareholders do not benefit from the efforts of these employees?

A. Both shareholders and customers benefit from these employees.

Q. But you're asking the ratepayers to pay

these costs, aren't you?

A. I think it's appropriate for the ratepayers to pay their portion of the cost for those employees, for the value they receive from those employees.

Q. But aren't you asking that the entire cost be on the ratepayers?

A. Yes.

Q. So you believe that the ratepayers are the only ones who benefit?

A. I think the ratepayers are the ones that have direct benefit from efficient, safe, reliable service. But, obviously, the stockholders of MDU Resources also benefits by a company that provides good services and a good rate of return and good customer service.

Q. Isn't one of the primary responsibilities of key employees is to make a profit for the company that in turn provides a dividend to shareholders?

A. That's correct.

Q. Your testimony in this case is essentially the same as it was in the MDU electric case that we heard a few months ago, isn't it?

A. That's correct. Yes, it is.

Q. Earlier I made reference to the findings of

fact, conclusions of law and order in the Commission's decision. In that case, which is PU-399-01-186, that decision issued on April 24, 2002, and the Commission has taken -- I believe has taken administrative notice of that decision.

Do you recognize the document that I've just handed you as a copy of that order?

A. I recognize it as what you referred to. I have not seen it previously.

Q. Would you please read paragraphs 66 and 67?

A. Paragraph 66, "Staff objects to including SISP in ratemaking expense. Diller testified that while the plan has been in effect since 1982, the company has never sought rate recovery in any subsequent electric or gas rate case. Staff opposes spending a million dollars a year on the benefit for a few employees. In addition to SISP, employees that are allowed to participate in SISP are paid very well, minimum of 75 to 80,000 per year, and participate in all other benefits offered to regular employees such as health insurance, life insurance, 401(k) participation, profit-sharing plans, incentive plans, defined benefit plans, Social Security, and discounted gas and electric service for those living in MDU's service territory."

Paragraph 67, "Diller testified that MDU's plan lacks symmetry and pointed out that the SISP benefits are heavily weighted in favor of the high-end salaried employees participating in the plan. For instance, an employee making $50,000 a year would receive a monthly SISP benefit of $1,330 per month, compared to a monthly benefit of $30,000 for an employee making $600,000 a year. In the case of a low-end employee, the monthly benefit calculates to be 2.66 percent of annual salary, compared to the high-end employee who would receive a monthly benefit of 5 percent of annual salary. Diller noted that only 27 employees of MDU's gas and electric employees are considered to be key employees."

Q. Is there anything factually incorrect in this description of Mr. Diller's testimony?

A. His facts and his math is correct to the extent it goes, yes.

Q. Okay. The number of employees, does that differ, the number of employees covered for this company, or is it the same employees basically covered?

A. Same basic group.

Q. And you read the description of benefits that these employees receive. Is that still true,

that they receive the same benefits that were described in the Commission's order in the electric case?

A. That's correct. Receive the same benefits.

Q. Isn't it true that even if this Commission doesn't allow the cost of this plan to be recovered in rates, the shareholders can continue to provide the benefit at shareholder expense? They can continue the plan just as it is right now, right?

A. Certainly they can and they may, because it's a competitive benefit that you need to attract and retain qualified people to run those operations and provide the service.

Q. What are the income ranges of the employees covered by this plan?

A. Montana-Dakota's range would be approximately $75,000 to its president, around 250,000 to 300,000.

Q. Does Montana include SISP as a cost to ratepayers?

A. I would defer to the regulatory staff on that, but I do not believe so.

Q. Does Wyoming include SISP as a cost to ratepayers?

A. The same answer. I would defer, but I

don't believe so.

Q. Same question for South Dakota?

A. And I don't believe so. I defer. At least I'm consistent.

Q. And as we've noted earlier, the North Dakota Commission has not included?

A. Not to this point.

Q. And, again, your testimony in this case and the position of Montana-Dakota Utilities Company is basically the same as it was in the electric rate case; isn't that correct?

A. That's correct. I provided a bit more information in my rebuttal testimony, but the basic facts remain the same.

Q. The electric case, a portion of that decision has been appealed by Montana-Dakota Utilities Company to the District Court. Isn't it true that the decision the Commission made on SISP, on the SISP issue, was not appealed?

A. I believe that is correct.

MR. BINEK: At this time, and I think administrative notice does this, but I just want to make certain that the findings of fact, conclusions of law and order in that electric proceeding would be incorporated into and made a part of this

proceeding.

MR. HOBERG: Yes, official notice would include that.

MR. BINEK: I have no further questions for this witness.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, do you have any questions?

COMMISSIONER REINBOLD: I think I do, a couple of them.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. A good deal of the questions and the answers were relative to the electric case that was before us and the parallel. How can it be that the electric and the gas case benefits and circumstances are practically the same even though MDU has some areas of the state that are only gas and some that are only electricity? How do you account for the perfect parallel?

A. I'm not sure there's a perfect parallel, but the management group are similar and common. The amount of time they spend in the respective areas are allocated out based on where they spend their time, as would these costs. So we believe,

you know, as a group of costs and group of employees and it's allocated out based on where they do their work. Some may be full electric and some may be full gas, and others are split.

Q. Maybe some are just -- is the company something like Melroe? Is that a parallel in management and management salaries, and so on, to MDU? Do you know anything about Melroe here?

A. That keeps changing, but it's similar for the Bobcat division, so to some extent, but more Ingersoll-Rand would be a parallel to MDU Resources at a corporate level, but we don't pay those kind of salaries or benefits.

Q. And say a few words about MDU employee retention. How does MDU do? And compare it to whatever you want to compare it to. That's a pretty broad question. Take a shot at it.

A. I think retention is one of our goals, because if you want safe, reliable service, you need people that know history and what's been going on in the past, as well as how it all works. So retention is a goal and I think we've been very successful at that, providing a great place to work, providing competitive pay and benefits to the extent we're allowed to, and having them motivated by what they

do, providing a public service. There's a lot of motivation in that. And so I think we are a desirable place to work.

Q. So that's one of your goals you say?

A. Oh, absolutely.

Q. Getting back to the allocation of time and effort and salary because of the natural gas and the electric services, is it conceivable that, for example, somebody like Don Ball would be working 85 percent in natural gas and 5 percent in electricity?

A. Currently, I suppose his current time is spent more on the gas side than electric side because of the rate case, but I think over time that would not necessarily be true, but Mr. Ball would know better how he allocates his time.

Q. Just a curiosity on my part because we do see him a great deal. And nobody was going to catch on the fact that I don't add up to 100 percent here.

MR. HOBERG: Where's the other 10 percent?

THE WITNESS: We consider that overtime and extra effort.

COMMISSIONER REINBOLD: I guess that's all my questions. Thank you.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. How many dollars is the company requesting in this case for SISP?

A. For the gas case I believe it's between 250 and $260,000 per year for 2002 and 2003.

Q. Where would I find this information? Where would I find that dollar number?

A. I'm going to defer in part to Rita and Tamie, but I found it someplace.

Q. Just take your time.

A. I believe it's in Statement N, as in November, page 8 of 23.

Q. Thank you. Page 8 of 23. It shows zero for the year 2001?

A. That's correct.

Q. And that's because nothing was allowed by the Commission?

A. Right. It has not been included previously.

Q. And so then you showed in 2002 a number and then 265,000 in 2003?

A. Right.

COMMISSIONER REINBOLD: Okay. Thank you.

MR. HOBERG: Thank you. Any further

questions, Commissioner Wefald?

COMMISSIONER WEFALD: No.

MR. HOBERG: Thank you. Commissioner Clark, please.

COMMISSIONER CLARK: I have no questions. Thank you.

MR. HOBERG: Thank you. Mr. Pearce, any further questions of Mr. Espeland?

MR. PEARCE: Just a couple.

REDIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Espeland, I think you've already alluded to this indirectly, but it is true, isn't it, that all of the SISP costs is not assigned to all of the utility operations?

A. Oh, absolutely. Only the portion that would apply directly to the utility.

Q. So SISP is applied to other operations?

A. Yes.

Q. Now, the meter fact that Montana-Dakota Utilities didn't appeal the SISP decision doesn't mean that you've changed your mind, does it, on the value of SISP?

A. Has not changed my mind at all.

Q. And all of the ratepayers benefit from all

of the compensation given to or provided for employees, don't they?

A. That's correct.

MR. PEARCE: That's all I have.

MR. HOBERG: Thank you, Mr. Pearce.

Anything further then of Mr. Espeland?

MR. BINEK: No.

MR. HOBERG: Thank you, Mr. Espeland.

THE WITNESS: Thank you very much.

MR. HOBERG: And your next witness, please, Mr. Pearce.

MR. PEARCE: Call Mr. Russell Feingold.

MR. HOBERG: Mr. Feingold, were you here earlier when I gave the admonition in regard to perjury?

THE WITNESS: Yes, I was.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, respond I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce, please.

RUSSELL A. FEINGOLD,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Feingold, you were retained in this proceeding by the applicant as an expert outside consultant; is that right?

A. That's right.

Q. And did you prepare or have prepared under your direction and control direct testimony consisting of answers and questions that was prefiled in this case?

A. Yes, that's correct.

Q. Looking at Exhibit 8, if you would, does that contain -- is that a copy of your prefiled direct testimony?

A. Yes, it is.

Q. Do you have any corrections that need to be made in your prefiled testimony?

A. No, I don't.

Q. To the best of your information and belief, is the information in that testimony, Exhibit 8, true and correct?

A. Yes, it is.

MR. PEARCE: I'll offer Exhibit 8. I have no direct questions.

MR. HOBERG: Thank you. Any objection to

Exhibit 8?

MR. BINEK: No objection.

MR. HOBERG: Exhibit 8 is admitted.

Mr. Binek, do you have any questions of Mr. Feingold on direct, please?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Feingold, on page 5 at lines 15 through 18 you discuss the wider acceptance of three-part rates for gas distribution service. Do you see that reference in your testimony?

A. Yes, I do.

COMMISSIONER REINBOLD: What number?

MR. BINEK: Lines 15 through 18 on page 5.

COMMISSIONER REINBOLD: Thank you.

Q. (MR. BINEK CONTINUING) Would you describe these rates?

A. Yes. These rates generally consist of tariffs that include a rate structure with multipart components of rates. Typically, there's a -- for gas companies a commodity charge, which would be charged on a variable basis, and then there would be fixed charges, in some cases a demand charge or a capacity charge and then a customer or monthly

service charge.

Q. I take it you believe that these are preferable to the two-part rates now in use by MDU in North Dakota; is that correct?

A. They are preferable from a strict cost recovery perspective. I think I allude in my testimony to the fact that in some cases for smaller customers you may not be able to apply a three-part rate as easily as you would to a larger customer.

Q. Why haven't you proposed these rates for MDU?

A. Well, I think you'd have to ask MDU's company witness, but I can give you my perspective from the standpoint of someone who is commenting on the tariffs. And I believe that with regard to the smaller customers, i.e., the residential customers, there is not metering capability at this point to fairly apply a three-part rate to the smallest customer served on the system. In lieu of that, though, one of the proposals that the company is making is to try to recover a greater component of fixed costs from fixed charges, which is why the company has proposed the monthly service charge proposal it has.

Q. If you were to propose three-part rates, to

what types of customers would they apply?

A. Well, if I look at other utilities in North America, typically the ones that have three-part rates applied to them first and foremost are larger, more sophisticated customers where the economics permit the use of daily demand metering technology or equipment to be able to fairly assess at least the demand or capacity component of the charges.

Q. Do you recommend that this Commission direct its gas utilities to develop three-part gas rates?

A. I think it's something that's worthwhile looking at in the future. I think in response to a data request that was asked of me by staff I alluded to the fact that in Connecticut, for example, the Commission in Connecticut has actually looked at and has approved three-part tariffs for midsize general service type customers.

Q. Much of your testimony is devoted to supporting the company's proposed increases in customer charges; is that correct?

A. Yes. Although, I would say more generally it's to recognize the fact that fixed costs should be recovered from stable or fixed components of the tariff.

Q. Are you familiar with similar proposals in other states?

A. In other states served by the applicant?

Q. By the applicant or in other states in general.

A. Yes.

Q. In both cases?

A. Yes.

Q. Have these proposals encountered much opposition?

A. Well, I'm not sure how you define "much opposition." Certainly, from my perspective, they're eminently reasonable. And in some cases there has been a disproportionate amount of movement toward cost-based fixed charges.

Q. Where there has been opposition, from whom has the opposition been expressed?

A. The opposition has been expressed primarily from consumer advocates, entities that are representing smaller, perhaps lower income customers, because their contention is that perhaps those customers would be experiencing a larger increase than would be warranted at that point in time.

Q. Have Commissions generally supported

efforts to double or triple customer charges as Montana-Dakota Utilities proposes in this case?

A. Well, I think, first, in the case of Montana-Dakota the proposal is to move from a $6.50 per month charge to $11.70, which is 39 cents per day as proposed. I don't think I've seen tripling of proposals as you are suggesting.

Q. What about the large customer?

A. What about large customers?

Q. Have their rates more than doubled or proposed charges, customer charges more than doubled?

A. Yes. However, it's a very different situation with larger customers because the revenues or the billings that are associated with the fixed monthly charge is a much larger -- smaller percentage of the customer's total bill, so they don't see it in the same way that a smaller customer would necessarily --

Q. But would you agree --

A. -- so it is more acceptable to Commissions, in my experience.

Q. I'd like to have you turn to page 8 of your testimony, lines 18 to 19. There you mentioned FERC's straight fixed-variable rate design for

interstate pipelines. Would you please describe that rate design?

A. Yes. Essentially, the FERC fixed-variable rate design is a -- I characterize it as a cost classification and allocation method that recovers fixed costs through a capacity or demand charge and variable costs through a commodity charge.

Q. Isn't the fixed part of that rate design tied to the maximum volume throughput of the customer and not to the customer's existence as a pipeline user?

A. Yes. And rightly so because pipelines don't serve hundreds of thousands of customers as an LDC does so they don't tend to classify and treat those costs in the same way that an LDC does.

Q. Would you agree that the appropriate analogy to FERC's fixed charges at the distribution level would be to a demand charge such as you discussed earlier and not to current customer charge?

A. From a strict rate design point of view, I would agree with you, but we have to recognize that some of the costs that are captured in the pipeline's capacity charge are costs that are appropriately recovered in the monthly customer

charge for an LDC.

Q. From page 12 on in your testimony you discuss the alternative distribution delivery stabilization mechanism which the company is proposing as an alternative to increasing customer charges. Just to refresh the Commission's memory, would you please provide a brief description of this mechanism?

A. Yes. The distribution delivery stabilization mechanism or more appropriately, the acronym DDSM, is a proposal that essentially adjusts the company's non-gas costs or a distribution margin to reflect changes in consumption as a result of changes in weather patterns.

Q. Do other utilities in other states have weather normalization adjustment mechanisms?

A. Yes.

Q. Are you familiar with these adjustments?

A. Yes, I am.

Q. Can you describe some of those mechanisms?

A. I'm not sure what aspect you're actually looking for me to describe beyond the general description I just gave you, which is essentially defining how all of the other mechanisms that I'm familiar with operate generally and what -- their

structure to accommodate.

Q. Do those mechanisms typically have a year's delay in the pass-through of the effect to warmer or colder weather?

A. There are some distribution utilities in North America that do have that feature, yes.

Q. Do most of them?

A. Most of them do not.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, do you have any questions of Mr. Feingold?

COMMISSIONER REINBOLD: Just a couple of questions.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. Have you been to North Dakota before this hearing?

A. Yes, I have, but have not testified before.

Q. Okay. Have you ever been to Mandan, North Dakota?

A. Yes, I was, and I think I was lost when I was driving.

Q. Okay. I don't have any real -- well, I've got a couple questions here just to make sure you

earn your money. RAFFCOSNCIFERCDDSMWNADSANUADZCK. What did I just say?

A. You mentioned every acronym that's in my testimony.

Q. Do you believe what I said to be an acronym?

A. It's a pretty long one, but, yes, I do.

Q. Quite technically it's not an acronym, unless it sounds like it might be a word and I can't imagine any of these being a word.

COMMISSIONER REINBOLD: That's all the questions I have at this time, but stay loose.

THE WITNESS: Okay. Thank you.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. On page 9 of your testimony -- I have trouble seeing the lines. I think it's 18 through 20 on page 9.

A. Yes.

Q. The proposed basic service charge increases will also ensure recovery by the company of a greater portion of its fixed costs of providing service.

If the higher customer charges were put in place, what proportion of the -- what proportion of the amount of income that MDU wishes to recover would be recovered by the basic service charge?

A. I think the way that I could answer that, Commissioner, is if you turn to page 10 of my testimony --

Q. Okay.

A. -- lines 20 through 23, I try to quantify, I think, the question that you posed, and that is if the monthly basic service charges were increased, and I focused on the residentials and general service customers, I talk about the amount of fixed costs that would be recovered. So, for example -- well, on page 10 in particular I say that there's still roughly $1.5 million of remaining customer-related costs and 3.3 million of fixed demand-related costs represented by 25 percent, so we're saying that roughly 75 percent of the fixed costs for the residential and general are recovered through the customer charge or monthly service charge.

Q. That being the case, would MDU have a greater opportunity to overreturn from those customer -- let's say the residential customer

group?

A. I don't believe so. And the reason I say that is because the costs that would be recovered in those basic monthly service charges represent the non-gas cost margin that would be established as a result of this rate proceeding. So under the assumption that that set number of dollars that represents distribution margin is what the company requires to have the opportunity to earn a fair rate of return, it's entirely appropriate to recover those in the fixed charges of those classes, but it doesn't in any way suggest that there would be the opportunity for overrecovery because of the way that they are being recovered through those charges.

Q. Why wouldn't there be an opportunity for overrecovery? Because in some years even with the present -- even with the present rate structure, if you have a really good year where it's cold and you're selling a lot of natural gas, then you're able to recover more income, and so why wouldn't that just be exacerbated then? I know you're going to be decreasing the cost of the natural gas to some extent for those customers, but still if you have a year where you're selling more than the normal, just explain that to me, why that would be there.

A. Certainly. I mean, if we recognize that the monthly service charges are applied on a customer's bill by essentially a monthly charge, so, in other words, if you have a $10-per-month monthly customer charge, whether you use zero decatherms of gas or 10 decatherms of gas in a particular month, you will be charged $10 because that reflects the recognition that the company incurs fixed costs that don't change whether the customer uses zero gas or 10 units of gas. Okay. So if it's a colder than normal year versus a warmer than normal year, it will not impact that $10-per-month charge applied to the number of customers served by the utility. In fact, it takes weather-sensitivity away from the utility business and instead of exacerbating, actually ameliorates the situation that you talk about with swings because of weather and that's one of the main reasons that this is being proposed.

Q. Are you the person to ask questions about how the rate design was done to establish that this is the correct amount of the residential gas service charge?

A. Well, I think the best person to ask that would be the next witness, Mrs. Aberle, but what I can answer here is that in reviewing the company's

embedded cost-of-service study, I was convinced that the numbers that came out of that study formed the basis for evaluating what rate level should we set in this case, so I'm comfortable with that connection. But I think she can talk to it in more detail.

Q. But it all depends on the assumptions that are put into that gas cost-of-service study as to which things are given to which customer group, correct?

A. That's correct, but I would venture to say based on my review of Mr. King's testimony, that with regard to the customer-related costs that form the basis for the monthly service charges, staff and the company are really not that far apart. It's a matter of how far do you go and how fast to get to cost-based rates.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

COMMISSIONER CLARK: I have no questions. Thank you.

MR. HOBERG: Any further questions then of Mr. Feingold? No further questions. Thank you, Mr. Feingold.

THE WITNESS: Thank you.

MR. HOBERG: You have one more witness on direct?

MR. PEARCE: Yes. I'll call Tamie Aberle.

MR. HOBERG: Ms. Aberle, were you here earlier when I gave the admonition in regard to perjury?

THE WITNESS: I was.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Mr. Pearce, please.

TAMIE ABERLE,

being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Did you prepare the direct testimony of Tamie Aberle that's been prefiled in this case?

A. I did.

Q. Looking at Exhibit 9, is that a copy of your testimony as prefiled?

A. Yes, it is.

Q. And if I were to ask the same questions,

would you give the same answers as are in that testimony?

A. Yes, I would.

Q. And to the best of your information and belief, is all of the information contained therein true and correct?

A. Yes.

MR. PEARCE: I will offer Exhibit 9 at this time, and I have no further questions on direct.

MR. HOBERG: Any objection to Exhibit 9, Mr. Binek?

MR. BINEK: No.

MR. HOBERG: Exhibit 9 is admitted. Thank you, Mr. Pearce. Mr. Binek, any questions of Ms. Aberle?

MR. BINEK: Just a few.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Concerning your proposed distribution and delivery stabilization mechanism that you discuss on page 12 of your testimony, do I understand this mechanism is being proposed only as an alternative to the dramatic increases in customer charges?

A. It is our secondary proposal in lieu of the increased customer service charges that we have

proposed.

Q. Okay. So does this then mean that if the company get the customer charge increase it is seeking in this case, the DDSM proposal is withdrawn?

A. Correct.

Q. What if the company get no rate increase whatever or even a rate reduction, what happens to the DDSM proposal?

A. I'm sorry. I believe I might have misspoken on your earlier question. I was speaking of the increase in the basic service charges, not the overall revenue increase. Our DDSM proposal would apply regardless of the increase or decrease in the overall rates, if we were not to receive the basic service charges that we proposed.

Q. Okay. But if you got the basic service charges, then you're not seeking the DDSM?

A. Correct.

MR. BINEK: That's all I have for right now.

MR. HOBERG: Thank you, Mr. Binek.

Commissioner Reinbold, do you have any questions?

COMMISSIONER REINBOLD: None at this time.

Thank you.

MR. HOBERG: Thank you. Commissioner Wefald, please.

COMMISSIONER WEFALD: No, I have no questions at this time.

MR. HOBERG: Thank you. Commissioner Clark?

COMMISSIONER CLARK: None. Thank you.

MR. HOBERG: Anything further then of this witness at this time?

MR. PEARCE: Nothing.

MR. HOBERG: Thank you, Ms. Aberle.

Let's take a 10-minute recess at this point.

MR. BINEK: Could we take a little bit longer time? I wasn't anticipating that my witnesses would be going up this soon.

MR. HOBERG: Fifteen minutes?

MR. BINEK: I think 15 minutes.

MR. HOBERG: Okay. We'll be back at 25 to 3:00, please.

(Recess was taken.)

(Exhibits 15-48, 16 and 17 were marked for identification.)

MR. HOBERG: We are back on the record

after a fairly short recess.

Before we begin the direct -- or the presentation of the State's case, we perhaps have some unfinished business. We have a couple of exhibits from MDU, is that correct, Mr. Pearce?

MR. PEARCE: Yes. I don't believe that I formally offered Exhibits 1 and 2. That's the application and the book of statements. I'll offer them at this time.

MR. HOBERG: Mr. Binek, any objection to 1 and 2?

MR. BINEK: No.

MR. HOBERG: Okay. Exhibits 1 and 2 are admitted. Thank you. Mr. Binek, please.

MR. BINEK: Thank you. I'll call Charles King.

MR. HOBERG: Mr. King, did you hear the admonition I gave in regard to perjury earlier?

THE WITNESS: Yes, I did.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: Yes, I do.

MR. HOBERG: Thank you. Mr. Binek, please.

CHARLES W. KING,

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BINEK:

Q. Please state your name for the record.

A. My name is Charles W. King.

Q. And what is your occupation, Mr. King?

A. I'm president of the economic consulting firm of Snavely King Majoros O'Connor & Lee.

Q. And what is your address, business address?

A. 1220 L Street N.W., Suite 410, Washington, D.C.

Q. Mr. King, have you -- how long have you been engaged in your present occupation?

A. In the present occupation close to 40 years. Virtually all my professional life.

Q. And you have testified in a number of state utility rate proceedings?

A. Yes. I've distributed a listing of my appearances and if you count them up, they come to over 300.

Q. Okay. And you have also appeared before the North Dakota Public Service Commission, have you not?

A. Yes. I appeared in MDU's electric case earlier this year and last year in Xcel's gas case.

Q. Let's see. Mr. King, I show you what has been marked as Exhibit 15-48. And can you identify that exhibit?

A. That's my testimony. I believe my exhibits are attached to it. Yes.

Q. And was this testimony prepared by you or at your direction?

A. Yes, it was.

Q. Are there any corrections that need to be made to your testimony?

A. No, there are not.

Q. And if I ask you the same questions today that are in your testimony, would your answers to those questions be the same as stated in your prefiled testimony?

A. Yes, they would.

Q. You also have before you Exhibits 16 and 17. Would you identify those exhibits?

A. One of them is a month-by-month statement of MDU's working capital, and the other one is an exhibit from the earlier MDU case, the electric case of earlier this year, and -- which shows the respective revenue sources for a number of

utilities.

MR. BINEK: Okay. At this time I will offer Exhibits 15, 16, and 17.

MR. HOBERG: Mr. Pearce, any objection to any of those exhibits?

MR. PEARCE: No.

MR. HOBERG: Exhibits 15, 16, and 17 are admitted.

MR. BINEK: Thank you.

Q. (MR. BINEK CONTINUING) At this time, Mr. King, I would like to ask you to give a summary of your testimony and also any rebuttal that you -- or any responses that you might have to the rebuttal testimony that has been filed by Montana-Dakota Utilities in this case.

A. Certainly. In the interest of time, I don't think I will go through in detail the portions of my testimony principally relating to rate design where I don't think there is any disagreement between us and the company. Unfortunately, most of my rate-of-return testimony there is disagreement.

The testimony overall deals with four subjects; the rate of return, cost allocation; that is, classed cost allocation, rate design, and, finally, the DDSM proposal. The cost -- I'm sorry.

Cost-of-capital testimony in turn has three parts. One is capital structure. The other is cost of the debt, and the other is cost of equity, and we don't seem to agree with MDU on any of them.

With regard to capital structure, there are two disagreements. One is that I include short-term debt and the company does not. And the other one is I used a historical 2001 capital structure and the company does a projected 2003 capital structure.

With regard to short-term debt, the reason for including short-term debt is that portions of the rate base are financed by short-term debt. If short-term debt were used for things totally out of rate base, such as expenses, then maybe we could exclude it, but, obviously, when you have elements that are in the rate base that vary throughout the year, why the company has to use short-term debt to finance that. And that's why I have my exhibit -- what is it -- 16 or 15? I didn't write it down. Sixteen, and this is taken from the company's Statement E.

And it's -- unfortunately, it is four of the five items that make up working capital. I did not -- I neglected to put in DSM expenses, but it wouldn't detract from what the exhibit shows, which

is throughout the year there is significant variation in the amount of working capital. And when you have that kind of variation, it's necessary to finance it through short-term debt. So I suggest that contrary to what the company says, it does not finance its working capital with long-term debt and equity, that there is an element of short-term debt. To be sure, it is a small amount. And you will find in my capital structure a relatively small amount of short-term debt.

As regards the forecast capital structure, the company's position in this case is considerably different than it was in the electric case. In the electric case the company accepted a historical end-of-year 2000, in that case 2000 capital structure. In this case the company wants a forecast capital structure. And I think it's mid -- it's the average for the year 2003. Now, the reason one uses future test years is to capture exogenous effects or outside effects, such as inflation, and in this case, the necessary expansion of the system into the northern suburbs of Bismarck.

These are things that are objectively determined. They are reasonably knowable. They are reasonably objectively analyzed. The capital

structure of the company is a creation of its own management. If the company says that its capital structure is going to change, there is no way of determining that, in fact, it will change in that manner. For this reason, most Commissions use historical -- recent, but historical capital structures, unless the company can articulate why the capital structure will change. Otherwise, you invite the company to engage in gaming of the regulatory system by projecting a capital structure usually with more equity than debt so that the overcomposite becomes more expensive. And I don't think the company should be permitted to do that in this case.

The debt cost we have a significant difference in. The company is proposing that the debt be limited to first mortgage bonds with a cost of 9.302 percent. I have proposed that we use a parent company's debt cost, which includes 6.167 percent. If -- I don't know if you want to look it up, but if you would want to look it up, Statement A, which is the company's balance sheet.

MR. HOBERG: In Exhibit 2.

THE WITNESS: Statement A in Exhibit 2. And earlier I asked Mr. Keller -- we asked

Mr. Keller whether the first two pages were for MDU Utilities Company. He answered yes. And if the subsequent pages pertain to MDU Resources Group, and the answer to that was yes. If you turn to page 11 of the Statement A, you'll find a list of long- term debt. That list does not begin to match the list that Mr. Keller has presented in Statement F, which is where he proposes his debt costs. The only debt that he shows is the secured medium-term notes, Series A, and then pollution control refunding revenue bonds. These are merely a portion of the parent company's total debt. Not included are -- and he has about 133,000 of first mortgage bonds. Not included are senior notes, $405,000 -- million dollars. Commercial paper, $219 million. Revolving line of credit, $25 million. Term credit agreements of $11 million and pollution control note obligations of $11 million -- I'm sorry -- $2.5 million. The company has reflected only a portion of its total debt.

Now, in rebuttal Mr. Keller has said that that doesn't -- other debt doesn't pertain to MDU Utilities, but you heard a few minutes ago that MDU Utilities Company isn't really a company. It's simply a division of the larger company. The larger

company is the entity that generates the debt, that raises the debt and distributes it to the subsidiaries. What the company has sought to do here is to build a firewall between the debt it wants to assign to the regulated piece and the debt it wants to assign to the unregulated piece. And, surprise, the debt it wants to assign to the regulated piece is 9 percent, and the debt it wants to assign to the unregulated piece ranges all the way down to 2 percent. And it should not be allowed to gain the system this way, by pretending that some debt pertains to the utility operations and other debt pertains to the non-utility operations.

Mr. Keller will tell you that that's how the debt instruments are written. Of course, they're written that way because that was how they were intended to be written so that they would appear that there is a distinction between debt raised for the utility and debt raised for the non-utility. Truth is, debt is all fungible. It could be spent anyplace the company chose to spend it. For that reason I have used the blended rate, debt rate of the entire company, meaning MDU Resources, as the debt cost. And it makes a very, very significant difference in the result. The debt

cost -- let me get my notes here -- again, is 9.3, if you use the company's first mortgage bonds as it proposes. It's 6.2 or 6.167, if you use the parent company's blended debt, which I developed in an exhibit to my testimony.

Now, equity, I have to kind of go through and tick off the items where Dr. Gaske and I disagree. The reality is we agree on a lot of things, specifically the formula for discounting cash flow, but, first of all, Dr. Gaske wants to include flotation costs. We're doing this all over again. In the electric case I demonstrated, and I simply repeat it in this docket, that if you include flotation costs, they come to .1 percent of the cost of the value of the total equity of the company. And I'm game to include that as a component of capital costs, but it would be lost in the rounding. Dr. Gaske seems to believe that it is appropriate to assign the incremental cost of flotation relative to the newly-issued stock and take that percentage and apply it to the entirety of equity. And this is a gross overcompensation of the company, and in the last case the Commission explicitly agreed with me.

Now, selection of comparison companies, Dr. Gaske point out correctly that in the Xcel

case -- I'm sorry -- in the last case. Two things, he points out in the Xcel case that I used a much different and smaller group of companies and I used both gas companies and combination companies. And the answer is I didn't really pick those companies. In that case I was rebutting Dr. Olson, who had made the pick. And rather than fight with Dr. Olson over the pick, I accepted his listing.

In the last MDU case, the electric company case, I took some purely electric companies and some combination companies, and I argued that the combination companies were more representative of MDU's electric service. And I was going to do what Dr. Gaske suggests, which is include full gas companies and combination companies until I looked at what has now been marked Exhibit 17, which is an exhibit that I entered into -- in the MDU case. And it shows the proper portion of the revenue of each of these companies. The companies in boldface are the ones I wound up selecting. If you look at those companies and look at the electric revenue and then look at the gas revenue, what you'll see is in every case the electric revenue is a multiple of the gas revenue. And as a consequence, while one can say that the investors might view these companies as

electric companies that also provide gas service, it doesn't work the other way around. No one views these companies as gas companies that also provide electric service, which is why I did not include these companies in my comparison group this time. Instead, I included purely gas companies.

Now, the other -- well, let's go through what I did that I don't think Dr. Gaske and I disagree with on. I used the DCF formula and I did two -- three versions of it. First, is the so-called classic version, which Dr. Gaske has another name for, and we also used pretty much the same sources; Zacks for the future forecast of earnings growth. And then we did the same development of dividend yield. We had the silly little disagreement over whether the growth factor for next year's dividend should be .5 -- or .5g, g being the growth factor, or .625g. And Dr. Gaske says that I don't reflect the time value of money. And he's right. I didn't. I just took half a year and said, all right, that's the probable time the next dividend increase will occur so we take one-half of growth, which seems logical.

Now, if I were to include the time value of money, I would probably reduce that .5. Why?

Because a dividend increase six months from now is worth less than a dividend increase right now. So I would have to take -- I would have to reduce that .5 by some factor reflecting half a year's loss in value because of the time value of money. So instead of increasing it as Dr. Gaske has done, I would have reduced the factor. But, again, we're talking about peanuts here in terms of impact on the total results.

The other thing I did was similar to Dr. Gaske's formula. I took the retention rate of the respective companies as determined by their dividend payout ratio or their earnings retention ratio times Value Line's forecast of their future return to book equity. And unlike Dr. Gaske, I added a piece for the probable or the likely increase in value that one would get from selling -- or companies would get from selling stock at greater than book value, which would enhance the book value of the shares. And I developed an internal retention growth estimate. And then I used -- I did get out the history of earnings gross and I developed that, and I think Dr. Gaske and I both agree that that probably isn't worth a whole lot.

I then developed what I regarded as the

composite rates of return for each of the 11 companies that I picked, as opposed to I think five or six that he used. And that was a judgment call, and Dr. Gaske is very unhappy with what I did there. But if you look at it, you will see what I have done in each case is taken the classic DCF return, which is probably the best estimator, and then turned and looked at the retention growth method. If the retention growth looks like it's totally out of whack with the forecast, and in some cases they are, simply no way that the company could be growing as fast or as slowly as the investor survey shows, I modified that classic DCF in the direction of the retention growth. And I came up with 11 estimates of the overall rate of return.

Then when I got those 11 estimates, I went through a little analysis of whether MDU is more or less risky than those 11 companies. And I determined a couple things. One is MDU has relatively high equity proportion in its capital structure, which saves it from a lot of financial risk that the other companies have. It was about equal to the best or the highest of the equity ratios. I don't pretend that that is the predictor of relative risk, but it is an element of relative

risk. Another element of relative risk is how much nonregulated activity the company has. In general, it's accepted that unregulated activities are riskier than regulated activities. Why? If your earnings are short, you come into a Commission like this and you get an increase in your rates. You have monopoly power. There is never a question that you're going to collect the money if the Commission let's you do it because you are a monopoly. That's not true of any unregulated activities. By definition, unregulated activities simply don't have the degree of security, the low-risk properties that regulated activities have.

There are a couple of other reasons I didn't mention in my testimony I probably ought to bring up now. Earlier in the day we heard from Mr. Fox that MDU was facing competition from propane and oil. Now, I live in Washington, D.C., and have done a lot of cases involving Washington Gas Light Company and so I'm familiar with competition there. There was no mention of competition from electricity. In Washington, D.C., the -- about two-thirds or three-quarters of the entire commercial load has been lost by the gas industry or the gas company to the electric company. And the

reason is that's a warmer climate. In Washington the climate is warm enough that you can build a compressor in an air-conditioning system that also heats. You can't do that in this climate. It would be ruinously expensive. Residentially you can sell people a heat pump. Heat pumps simply don't work in North Dakota. You freeze to death, along with paying an astronomical electric bill. So the relative degree of competition for gas in North Dakota, I submit, is considerably less than it is elsewhere in the country.

There's another difference. In Washington and even in Spades and Atlanta there is a much more active competitive supplier business. In Atlanta, the other company I'm familiar with, the Commission decided to totally restructure the gas industry. That no one -- the utility would no longer buy gas on behalf of its customers. It would have instead merchants would come in and you would be a customer of the ABC Gas Company, which would buy your gas and pay Atlanta Gas Light to deliver it to your house. So that from 600,000 customers, Atlanta Gas Light went to 11 customers.

That sounded like a wonderful idea, except that one of them with a nice Georgian name of

Peachtree Energy went bust and left Atlanta Gas Light hanging for quite a few million dollars, just stiffed them flat, and the company suffered a very significant loss. And Washington Gas Light has a similar problem. They've lost about two-thirds of their commercial load to competitive suppliers. Now, they still use WGL as their delivery to customers. One of the problems is that they haven't got the transportation capacity locked up that WGL had. And there's a great fear that if we have a cold winter, these people aren't going to be able to get the gas into Washington. Those are risks that larger companies have that MDU doesn't have because MDU does not seem to have anything like the active competition for the gas supply business that you get in bigger places.

So I think that is an important difference between MDU -- those two, the degree of competition and the effect of suppliers, is an important reason why MDU is probably less risky than the average utility, in addition to the point that I make in my testimony. Dr. Gaske says that MDU has the risk characteristics of a small company. Well, he's comparing apples and oranges. He's comparing the gas distribution business of a large company with

the risk properties of a small company, a small stand-alone company. What we're trying to find is not that. We're trying to find the risk characteristics of the gas operations of a large company. A large company gives you the security of financial strength and also diversification of financial resources. You remember where all those extra sources of debt came from, which a small company doesn't have and small companies indeed are more risky, but only when they are stand-alone operations. Principally, because their sources of financing and the support they can put behind that financing in terms of business is much less.

Well, all this comes together on page 34 of my testimony where I present my composite cost of capital and that is -- there I take the proportion of the capital structure, the cost elements, and the weighted costs. I've come up with 10.5 percent as a cost of equity, which is halfway between the average cost of equity of my 11 companies and the lowest cost of equity within that category, that group of 11 companies, reflecting the fact that MDU is less risky than the average for the 11. That's 10.5 and then you get the weighted cost in the final column, overall return to capital is 7.98.

Now, the rest of my testimony deals with capital structure. The only area where I think I seem to hear disagreement from the company pertains to the cost of service study. Where Ms. Aberle says that customers cause most or half the cost or a third of the cost, I believe is their position, of the mains system. And I take exception to that.

And the reason is that the main system may be driven by the addition or -- well, never the subtraction, but always the addition of customers, but only out in the margins. Indeed, they're putting more mains out in north Bismarck, but you heard testimony earlier that they only add 1 percent more customers every year, so that's a negligible impact on the cost of mains. Most of the cost of the mains is what you call an embedded cost. It's there. It's been there for centuries -- I mean, for decades. And it's not going to be affected by any increase or decrease in the number of customers. It's not going to be affected by any increase or decrease in the amount of gas that goes through it. It will be impacted by the maximum amount of gas that goes through in any one day, but we reflect that. We recognize that in allocating a portion of the main's cost to throughput as among the various

classes of customers.

My -- when you can't find causation and that's the case with mains. They are simply there, what I would call an institutional cost. They're not caused by anything. They're there. When you can't find causation, then maybe you should look to value of service as an allocator. And value of service is measured by the amount of gas delivered to each of the three or four various categories of customers, which is what I have done in the alternative calculation that I have presented. And it does change the results some, but not a whole lot. We both agree that the small interruptible customers are being overcharged. We don't agree quite about what to do about it. The company would reduce their rates while increasing everybody else's rates.

I went through a number of previous Commission decisions, not just with MDU, but with all the other gas companies and also electric companies, and it appears to have been this Commission's policy over the years that when there is a rate increase, everybody ought to bear a little of the pain. And if you want to even out differences among the classes, you might change the

percentage increase, but everybody get some increase. And what I have seen is a number of cases where the overcharged class got half the increase that the undercharged class got. And that's what I proposed in this case. If you increase rates, increase everybody but the small interruptible customers and then give them half the increase you get for the rest.

The other rate design issue deals with this matter of customer charge increases. What the company and I agree on is that we should get rid of the declining block commodity rate and take the revenues you get from those high early blocks and put that in the customer charge. So even if we do nothing whatever in terms of overall revenue recovery, we would be increasing the customer charge as the company wishes. And then I agree that probably if we're going to have a rate increase, we might flow more of that increase into the customer charge than into the commodity charge. But nothing like the enormous increases in the customer charge that the company has proposed.

If we have a rate decrease, which is what staff is recommending, I would recommend that that decrease come entirely out of the customer charge --

I beg your pardon -- out of the commodity charge and the customer charge be left untouched. Well, actually they would be increased because we're flattening the rates, but the revenue recovered from the customer charge plus the early block pieces would not be reduced. We would flow all the reductions into the commodity charge.

On the DDSM, I don't even know whether there's a proposal still, but if it is, I think it's one that should be rejected because of the year's deferral. It could really backfire big time and get us all in a great deal of trouble, because if you had a warm winter and you tallied up a whole lot of money that you ought to collect from ratepayers because you didn't pay very much last winter and this winter it's colder than all get-out and everybody is paying enormous gas bills, both because of the amount of gas they're using and because the price of gas usually goes up when you have a cold winter and then on top of that you hit them with a DDSM charge, it will be very, very unpopular.

If you're going to have a weather normalization program -- I think they're not a bad idea. More and more states are using them. -- they have to be maybe not real-time, but they have to be

concurrent. The warm weather charges that you want to collect from customers have to flow to customers during the warm weather and the cold weather charges that you would to subtract from their customer bills have to be during the cold weather. Otherwise, you are losing the effects, the beneficial effects on ratepayers, which is to even out their year-to-year gas charges.

I think I've said quite enough so I'm going to shut up right now. Thank you very much.

MR. BINEK: At this point I tender the witness for cross-examination.

MR. HOBERG: Thank you, Mr. Binek. Mr. Pearce, if you have any questions.

MR. PEARCE: Yes, I do have several.

CROSS-EXAMINATION

BY MR. PEARCE:

Q. This is just a minor point, but turning to page 2 of your testimony, Mr. King, line 23 and line 27, I suppose you mean gas there. You have electric operation there in both cases.

A. Oh, dear. I'm sorry. That part of my testimony I had simply taken and listed from the earlier.

MR. HOBERG: So you would agree that should

be gas?

THE WITNESS: Yes, it should be gas.

Q. (MR. PEARCE CONTINUING) One of the downsides of word processing, isn't it?

A. That's right.

Q. Exhibit 17, I think, was just introduced and it's electric and gas utilities percent regulated revenue?

A. Yeah.

Q. I think you said you introduced that in the electric case. Dr. Gaske tells me that he introduced that as part of his testimony in the electric case. It's not critical, but maybe --

A. Well, I don't care who introduced it. I thought it was mine, but welcome -- nonetheless, it shows what it shows.

Q. Right. We'll both accept that as true. Now, turning to page 28 in your testimony through 29, I just wanted to clarify a point. It's your testimony that by your understanding Dr. Gaske's 1.625g factor there is based on his assumption that the first dividend would be received three months from the date of purchase; is that right?

A. Well, that's how I calculated it, but Dr. Gaske says that isn't so and I'll let him

explain why it isn't so.

Q. Now, have you -- Dr. Gaske's prefiled testimony, rebuttal testimony is in the record, although it hasn't been introduced as an exhibit. I think you said you had read it; is that right?

A. Yes.

Q. If I could just show you one page, although it's not an exhibit yet, but just to make sure we are on the same wavelength. I'm looking at his JSG-4, page 2 of 3 on Schedule 3. It has the -- I believe what's the classic DCF formula. I just wanted to confirm that we agree that that's the --

A. I think it is, yes.

Q. Okay. Now, turning back to page 20 of your prefiled testimony, and this is the testimony right after your table 7 at the bottom of the page. You say -- in fact, it's the last line of that page, line 22. For example, there are no examples of level or declining earnings in the Value Line forecasts. I'm going to show you --

(Exhibit 18 was marked for identification.)

Q. (MR. PEARCE CONTINUING) Exhibit 18 is a packet of six pages, and before I identify it further, could I ask you -- well, let me back up.

Which issue of Value Line did you use for

your analysis? Do you have that there?

A. Mine are all dated June 21.

Q. Of 2002?

A. Yeah.

Q. Okay. Now, looking at what's been marked as Exhibit 18, it is -- and I'll tell you what it is, is sheets from Value Line for six companies of that same date. Would you agree that's what it appears to be?

A. Yeah. None of them are the six companies that I was analyzing.

Q. Right. Right. No.

A. Or the 11 companies.

Q. You make in your testimony a very broad statement about Value Line. I just wanted to lead you over to some other companies that were not in your testimony.

A. Well, I didn't mean to imply that they never, ever predict declining earnings. I was talking about among the 11 companies that I was looking at.

Q. Okay. Just to go through this, looking at these companies, and I realize this is very fine print for a person of my age, but looking at the third line there, earnings per share, and then down

toward the bottom is return on common equity, I think. Would you agree if you have a chance to look at each of these six sheets, that there is, in fact, declining earnings and earnings per share from 2000 -- between 2000 and 2001 and, in fact, out through the 2005, 2007 period?

A. Oh, sure, for these companies. These are in the oil business. I don't know what Holly Corp is. Crude oil. We're looking at oil companies for some reason.

Q. I believe they're all energy companies.

A. Tesoro is one of them.

Q. Right.

MR. HOBERG: Are you offering Exhibit 18, Mr. Pearce?

MR. PEARCE: Yes.

MR. HOBERG: Any objection to 18, Mr. Binek?

MR. BINEK: Well, the only objection I would have is based on the comments that Mr. King has made, that none of the companies that he's talking about are included here, and so I guess I would question the relevance of this.

MR. HOBERG: What is the relevancy, Mr. Pearce?

MR. PEARCE: The way the testimony is written the implication appears to be that all of Value Line's companies that it analyzes are overly optimistic and there's never any report of declining earnings and we simply wanted to show that although -- that without regard just to utility companies, as a general principle, that's not true for Value Line generally.

MR. HOBERG: Do you have any objection for that limited purpose, Mr. Binek?

MR. BINEK: No, I guess that's okay.

MR. HOBERG: I'll admit Exhibit 18.

MR. PEARCE: That's all the questions I have.

MR. HOBERG: Thank you, Mr. Pearce.

Commissioner Reinbold, did you have any questions of Mr. King?

COMMISSIONER REINBOLD: Yes, I do.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. Mr. King, you said something about heat pumps wouldn't work in this part of the country in North Dakota?

A. That's what I've been told. I'm not an engineer and I can't really testify as an expert on

that subject.

Q. Would it surprise you if I directed you to a window in this room and directed you to look to the northwest and see a brand-new huge church building which is being heated and cooled by 120 wells 160 feet deep in the parking lot?

A. Goodness.

Q. Doing it very efficiently. A young entrepreneur, who was a well driller, got it started and he's worked this type of work as far away as South Carolina. So it may not work everywhere, but it does work over at our church. It's very expensive and it will be expensive for a long time, but it does work.

A. I hope you're comfortable at Christmastime.

COMMISSIONER REINBOLD: That's all I have for now.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

COMMISSIONER WEFALD: Yes, I have a few questions.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. On page 34. I understand there's a disagreement between the company and the staff about

whether short-term debt should be included and as you've said, it's only 2.78 percent that you've included in your calculations.

A. That's right.

Q. And you're asserting -- my first question is, are you asserting that short-term debt should be included?

A. Yes.

Q. Because you have information on the record and where is that that shows that they're using short-term debt?

A. Well, you never know. You can't trace the source of money from where they get it to where they use it because it all goes in effect into the bank account and then back out again. But the proposition is that when you have expenses that fluctuate -- or capital costs or expenses that fluctuate, particularly capital costs fluctuate month to month, the normal way of financing those would be through short-term debt. Now, they are high in June and low in January and where are you going to get the money to cover those, you go to the bank and borrow it.

Now, in fairness, MDU does not use much short-term debt. And the reason is that the company

generates a lot of internal cash primarily from excessive depreciation charges, but that's what Mr. Majoros is going to talk about. But they do use some, and this is what I reflect here. And the reason I put in this exhibit is to show that there's significant variation from month to month in the working capital.

Q. How did you come up with this?

A. It's from the company's own -- well, the numbers are presented up in the front. Let me find the table for you. It's page 5.

Q. Yes.

A. Table 1.

Q. But I just wondered how you were able to determine it was $9,639,000 --

A. That I think I got from there --

Q. -- if you said it's hard to trace?

A. Oh, you can determine how much short-term debt there is. What you can't do is determine where they spent it. That's what I meant is hard to trace. I believe I got that -- here it is. Look at my Exhibit CWK-1, which is attached to my testimony.

Q. Okay.

A. Go to the last page of that exhibit and

there at the bottom you'll see the 9 million and you'll see the 4.542 percent. That's the source of those numbers. And this is a company data response.

Q. All right. And on page 43 of your testimony you talk about penalties for failure to interrupt should be increased, on line 11.

A. Yes.

Q. Do you have any recommendations about that?

A. Well, I was going to recommend the company's proposal be accepted. And it's the company's judgment as to what it takes to make interruptible customers interrupt, but if they don't interrupt, you could have a disaster. You can have the pipeline suddenly unable to deliver gas to the city gate and everybody goes cold. So if -- and the company isn't planning. They don't make the commitment to the pipelines. They don't build their own main structure to handle the interruptible customers' loads at the peak day. The assumption is when it really gets high gas demand, phone them up, have them cut off. They don't cut off, the company can be in trouble.

Q. Right.

A. So I think it's very important that there be sufficient pricing to persuade those customers

they better interrupt.

Q. Well, what I was wondering is, it says here, penalties for failure to interrupt should be increased since the company apparently believes that the current penalties are not sufficient. So did the company present what you feel is a sufficient penalty then to --

A. Well, I really do have to defer to the company. I guess I accepted their judgment in that regard. Maybe I'm naive, but in this regard I --

Q. You're not disputing what they're proposing?

A. I'm not disputing their judgment on that. But I think if you want to know what is the basis of the exact amount of increase, you better ask Ms. Aberle.

Q. All right. Then my next question was page 44. This is under the question, have you calculated the increased customer charges that would result from eliminating declining block rates. It's my understanding that you think that we should be eliminating the declining block rates. And so is it your recommendation that this size increase that is reflected in paragraphs 19 through 23 is what should be put in place for customers?

A. Well, what I did in my Exhibit CWK-8 was calculate the revenue that is recovered in the high initial blocks of the present rate structure. And then I divided that by the number of customer bills and got the amount of increase you would need in the monthly customer charges in order to recapture that same money in the customer charges instead of in the initial declining block rates. And that's the numbers you see here. This is a totally revenue neutral proposal.

Q. Right. I see. This doesn't reflect any increase that the company may want?

A. No increase, right.

Q. This is just what would occur if you eliminated the declining block rate?

A. Right.

Q. So then this would be the minimal amount -- this would be the bottom amount that we would be looking at --

A. Yeah.

Q. -- for a customer rate increase before you'd --

A. Yeah.

Q. -- project any -- if you were going to do any increase for their rate case?

A. Right. What I'm suggesting is, even if you reduce rates, you ought to keep these customer charges, because I am sympathetic to the company's desire to capture somewhat more fixed costs in the customer charge. So I think if you were to reduce the rates, it would be inappropriate to reduce the customer charge. Reductions ought to come out of the commodities.

Q. Even in this situation for the large customer who goes from $17 to $45, which is a triple increase?

A. It's a big increase, but it is, as I believe an earlier witness pointed out, those customers use so much gas that this is small potatoes in terms of their total bill.

Q. All right. And then on page 45, the question is, are there any other proposals the company has made that you believe the Commission should consider regardless of the change in overall revenues, and your answer is on lines 12 through 19. I recommend the Commission consider the company's proposal to convert the basic service customer charge from a monthly charge to a daily charge. And then you go on and then you say. My only concern is whether it might be accepted by the average customer

as a reasonable way of charging for service.

To me it would be very confusing as a customer to not know every month, not to have the same amount each month on my bill for my customer charge.

A. Yeah, and I'm sympathetic to that. I think that's a legitimate concern and that's why I put that sentence in there. I guess I'm tossing the ball back to you as to whether you think that is something that will go down with the average customer.

Q. Because, otherwise, you might have one rate that would be there for the 28-day month, another one for the 30-day month and another for the 31?

A. You get a lower customer charge in February, right. But I think the virtue from the company's standpoint is it gives them a little more flexibility as to when they send their meter readers out. Now, it's got to be -- I guess I don't know whether they bill by the calendar month or whether they bill -- each customer get from a certain day to a certain day, but whatever it is, they're locked into pretty much a 30-, 31-day interval and this would permit them to alter the interval, if they had to.

Also, we put in a data request asking how many customers did they have that had partial month bills in a given year, and it was a huge number. I don't know why, but it was -- I was surprised by how big it was. And it's one of the reasons that I sort of gave a backhanded endorsement to this proposal. But it's certainly not something that I would insist on.

Q. When you say -- what do you mean by a partial month bill?

A. What we asked was in any given -- I don't have the data response with me. They had said they had a lot of customers who came -- who got on and off during the year. And the consequence of signing on for a part of a month instead of the full 30 days, they had 20 days or 10 days or whatever. And I said, all right, well, how big a deal is that? How often does that occur? And it was in the thousands. It was quite remarkable that it was as much as it was. Evidently, there must be a lot of customers who simply turn off gas service in the course of the year and disconnect. And then reconnect later. It could be vacation homes or people who decide they don't need gas in the summer because they don't need the heat in the summer and

they cancel gas service. You have to ask the company why it's so large, but it was a large number. And this would facilitate dealing with that problem.

Q. I will ask the company a few more questions about this, but then does it also -- in your understanding of this does it reflect -- let's say the company read my meter on January 15 and then they didn't get around to reading my meter again until the 20th of February. So then there might be -- would I get a 30-something day --

A. Thirty-five-day month, it's possible.

Q. And then the next I get a 25-day one if they went back and did it again on the 15th again of the next month?

A. If you're like me, you write your bills once a month when you get paid, and customers could really get messed up if they started changing the -- if they got out of the monthly cycle of billing, which this would permit them to do. So maybe that's a good reason not to permit this change.

COMMISSIONER WEFALD: Who would be the MDU person I would ask these questions of just so I can understand it better?

MR. HOBERG: Mr. Pearce?

MR. PEARCE: I suppose probably Mrs. Aberle.

MR. HOBERG: Tamie Aberle.

COMMISSIONER WEFALD: I do have some questions about that so I will ask Ms. Aberle.

Q. (COMMISSIONER WEFALD CONTINUING) All right. And then, now, this is a bigger, broader question.

A. I like big, broad questions. I give big, broad answers.

Q. So now let's say a hypothetical utility has divisions and one of them makes -- one of these 11 divisions that they have and only one is a utility division, but it's still a -- it's a company with many subsidiaries, and one is the utilities and one of those divisions makes bad business decisions and starts to go into a -- close to a bankruptcy situation. So within the -- it's my understanding what happens sometimes then is that the bond rating of the whole company can get lowered and then a Commission has to worry about what are the -- whether the riskiness of their bond rating at that time is going to be passed on to their customers.

When you're talking about looking at bonds for the whole group of MDU companies, all of these

divisions, if I accept your premise that the bonds are good for everyone and it's the whole, big company that has a bond rating and not just one division, am I setting myself up in the future then to set precedents that if they make a bad decision with one of their divisions, that I'm going to need to accept that bond rating for the utility company as well?

A. Well, you have exactly that situation with your telephone company.

Q. Right.

A. And it's a difficult problem. US West was a thoroughly successful company, but it got bought by this Qwest outfit, which has gone south, and it's junk bond status. And your question is, okay, what are you going to do about assigning a bond yield cost to US West?

Q. Well, and I don't have to worry about that because under price cap, but let's say there's a hypothetical company that's in the same situation, but we know that that's reality in some cases today. And so what I'm concerned about is your --

A. Well, what I would say is that if the utility piece of it is a -- is profitable and would support an adequate bond rating, then for -- but the

rest of the company caused it to go south, I think you would have to impute a bond cost that reflected the utility's performance. Fortunately, for MDU Resources that's not an issue, because not only is the utility profitable, but the parent company is also profitable.

But I think your concern is a very legitimate one, that if the non-utility activities of the company soured the bond ratings such that there were astronomically high debt costs, is it fair to ratepayers to pass those debt costs through to them? And I would say no, because that is a result of -- it's in a way analogous to why we don't use MDU's equity costs because its equity cost is seriously influenced by its nonregulated activities. If you could demonstrate that the bond -- the debt cost is influenced adversely by the nonregulated activities, then I think it's appropriate to impute a different debt cost. Fortunately, I don't think that's an issue here because it's clear that the company seems to have a good debt rating.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commission Clark, please.

COMMISSIONER CLARK: I have none. Thank

you.

MR. HOBERG: Thank you. Any further questions of Mr. King? Mr. Binek?

MR. BINEK: Just one.

REDIRECT EXAMINATION

BY MR. BINEK:

Q. I guess I would like a little bit of clarification about this heat pump business. When you were making reference to the use of heat pumps, you were -- I'm assuming you were thinking about a unit that does both heating and air conditioning, kind of a stand-alone unit, versus something that draws heat off of groundwater?

A. Yeah.

Q. Is that correct?

A. Mr. Majoros can testify about heat pumps. He has one in his house and he says he hates it.

Q. Okay. But there are different kinds of heat pumps?

A. Yes. Essentially, it's an air-conditioner that works two ways, and it only works as an air-conditioner in the reverse direction down, I'm told, to about 45 degrees Fahrenheit. If it get colder than that, you have to supplement with resistance, electric resistance heating, which is

why it becomes very expensive if you have a cold climate, because up here you would have that resistance heating on all the time and that scarfs up an incredible amount of electricity.

Q. These are the kinds of units that we often see in motels; isn't that right?

A. Yeah.

MR. BINEK: Okay. No further questions.

MR. HOBERG: Thank you, Mr. Binek. Mr. Diller, any questions? Okay. Anything further then of Mr. King? Thank you, Mr. King.

Let's take a short break and then we can perhaps take Mr. Majoros and finish off the day that way. Let's be back at -- a five- to seven-minute recess.

(Recess was taken.)

(Exhibits 19 and 20 were marked for identification.)

MR. HOBERG: We're back from a short recess. And, Mr. Binek, you were ready to call your next witness.

MR. BINEK: Yes. I will call Michael Majoros.

MR. HOBERG: Mr. Majoros, you were here earlier when I gave the admonition regarding

perjury; is that correct?

THE WITNESS: Yes, sir.

MR. HOBERG: Being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Binek, please.

MR. BINEK: Thank you.

MICHAEL J. MAJOROS, JR.,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BINEK:

Q. Would you state your full name for the record, please.

A. Yes. My name is Michael J. Majoros, Jr.

Q. What is your occupation, Mr. Majoros?

A. I'm vice-president of the economic consulting firm of Snavely King Majoros O'Connor and Lee, Incorporated.

Q. And how long have you been at that firm?

A. Approximately 22 years.

Q. What is your educational background?

A. My educational background is in accounting. I've passed the CPA exam, taken courses in the MBA

program at George Washington University, and have taken several continuing education courses.

Q. And you have testified in a number of state commission utility rate cases?

A. Yes, sir.

Q. You have before you documents Exhibit 19-49, I think it is, and Exhibit 20. Could you please identify those two exhibits?

A. Yes. Exhibit 19-49 consists of my testimony, my Appendix A, which is a summary of my qualifications and experience, and my Exhibits MJM-1 through MJM 12.

Q. And what is Exhibit 20?

A. Exhibit 20 is a packet of exhibits I prepared in response to primarily Mr. Jeter's rebuttal to me.

MR. BINEK: At this time I would offer Exhibits 19 and 20.

MR. HOBERG: Mr. Pearce, any objections to Exhibit 19?

MR. PEARCE: No.

MR. HOBERG: How about 20?

MR. PEARCE: No.

MR. HOBERG: Exhibits 19 and 20 are admitted.

Q. (MR. BINEK CONTINUING) I should have asked, if I were to ask you the same questions today that are in your testimony, would your answers be the same?

A. Yes, sir.

Q. Are there any errors in your testimony that need to be corrected?

A. I noted a couple of typos, but the one that I would like to correct is on page 5, line 5. There's a range of years in that sentence, 1996 to 2000. I'd like to change that to 2003.

Q. Any other corrections?

A. No. No, sir.

Q. At this time I would ask that you please provide a summary of your testimony and also provide any response that you may have to rebuttal testimony that has been filed by Montana-Dakota Utilities in response to your direct testimony.

A. Okay. The objective of my testimony is to recommend the appropriate jurisdictional revenue requirements for the North Dakota gas division of Montana-Dakota Utilities, Incorporated. I've attempted to recognize the legitimate needs of the company to recover its costs, but at the same time I've attempted to ameliorate any added burden on

ratepayers from excessive recoveries. Ms. Mulkern proposes a $2.8-million base rate increase using an 11.44 percent rate of return. I recommend a $1.4-million base rate decrease using Mr. King's recommended 7.98 percent rate of return. My adjustments are summarized at page 3 of my testimony.

I propose to reduce the Company's depreciation rates. I propose to eliminate bonuses and commissions from the company's costs and hold the 2003 labor cost levels equal to the 2002 levels. I propose to eliminate the SISP from benefits expense. I propose a five-year rather than three-year rate case amortization period. And I propose to eliminate the general inflation from other unadjusted operation and maintenance expenses.

At pages 4 to 7 of my testimony I've included certain financial analyses. At the top of page 4 of my testimony I demonstrate that the company's gross margins declined from 2001 to 2003. The decline is caused by major increases to operation and maintenance expenses, excluding the cost of gas. Increased O&M expenses is a major driver in this rate case. From 1996 to 2003 O&M expenses, excluding the cost of gas, increased at a

compound rate of 2.5 percent. And that is shown on my Exhibit MJM-2. However, that 2.5 percent is slightly misleading because from 2000 to 2003 the expense is actually ratcheted up and continued on from there. The compound growth rate from 2000 to 2003 is actually 5.7 percent, which, in my opinion, is unreasonable.

I am also recommending a change in depreciation rates. Since depreciation produces cash flow for this company, I conducted certain cash flow analyses. Although depreciation is not intended to finance capital additions, some equate it to additions as if that was its intent. As I stated in my testimony, the purpose of depreciation is not to finance plant additions. Nevertheless, I've determined that this company's depreciation seems to always produce more than sufficient cash flow to cover its additions.

At page 6 of my testimony I've included a table of -- comparing annual depreciation cash flow to annual construction additions at the total company level for the years 1996 to 2002. Mr. Jeter challenged this table so I've provided an expanded table, which is the first page of Exhibit 20. Even with the revisions --

COMMISSIONER WEFALD: Where is Exhibit 20, please?

MR. HOBERG: That's the one that was just introduced, that separate one.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: Even with Mr. Jeter's changes, at the total company level since 1996 this company's depreciation expense has exceeded its capital additions by $409,000. I also -- Mr. Jeter also challenged my Exhibit MJM-3, where I compared the gas utility only depreciation expense to additions. Mr. Jeter claimed that I failed to include common plant depreciation expense in column 2. Consequently, on the third page of Exhibit 20 I've made the adjustment in accordance with Mr. Jeter's testimony. And what this demonstrates is that since 1986 this company's gas company North Dakota depreciation expense has exceeded the additions to gas plants in North Dakota by $8.2 million. In my opinion, this has resulted from excessive depreciation rates which have been charged to ratepayers.

At page 7 of my testimony I cite and quote from what I consider to be a landmark U.S. Supreme Court decision on the subject of depreciation.

COMMISSIONER WEFALD: That's where?

THE WITNESS: Page 7 of my direct testimony.

COMMISSIONER WEFALD: Page 7. Thank you.

THE WITNESS: In that case, which is known as Lindheimer v. Illinois Bell, the Court equated excessive depreciation to the extraction of capital contributions from ratepayers. And it clearly stated in the beginning of the second paragraph, Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. This morning I heard the word "confiscation" from Mr. Gaske, and I understand the company in this case has the burden of proof. And my testimony states that their depreciation expense is excessive, and I provided my reasons for making that claim.

Here's how I arrived at that conclusion. First, I reviewed this company's depreciation reserve levels and that's accumulated depreciation. I have testified or been involved in more than 80 proceedings on the subject of public utilities depreciation. Based on my experience, if you refer to page 9 of my testimony, the 70.7 percent reserve

ratio for the distribution plant is very, very high. And it suggests that prior depreciation rates may have been excessive. I asked the company if it conducted any studies to measure the adequacy of that reserve and it has not. The company's current depreciation rates are based upon an 11-year-old study conducted by Stone & Webster, which does not exist anymore, at least Stone & Webster doesn't, to the best of my knowledge.

That was the next place I looked. I've included as MJM-4 to my testimony the first few pages from that Stone & Webster study. These are also included in the company's Statement I, if I could refer you to those pages. Two things caught my eye in reviewing this. The first thing that caught my eye was the negative 140 percent net salvage ratio for services. That is shown in about the fourth column. It says estimated retirement costs percent amount.

COMMISSIONER WEFALD: Will you just show me what you're looking at?

THE WITNESS: I'm looking at Exhibit MJM-4, page 1 of 2.

COMMISSIONER WEFALD: MJM. Thank you.

THE WITNESS: About halfway down -- well, a

third of the way down the page, account 380, the second number in that line is negative 140. And that's a very, very high negative net salvage ratio. That also suggested to me the possibility the current depreciation rates are excessive.

The next thing that caught my eye, if you come over three columns, the column that starts with the number 39 and then goes to 36, those are average service lives. The average service life for distribution mains, which is the single largest account on the company's books, is 36 years. If you put a circle around that, and then coming down the page, the average service life for services, which is the second largest account, is 34 years. Based on my experience with gas companies, those are very, very short lives. Short lives equate to high depreciation rates. If they're too short, the resulting depreciation rates are excessive.

Consequently, I conducted certain tests of those lives based upon the information available to me. These are called geometric mean turnover analyses. They're included as Exhibit MJM-5. And these two analyses would indicate that overall the average service life for mains is in the 108-year range and the average service life for services is

in the 69-year range. Mr. Jeter, through a data request, identified certain discrepancies in my calculations. So I redid the GMT studies. They're included again with Exhibit 20. And when I make the adjustments identified in the company's data request, the corrected GMT studies would support lives for mains of 116 years and lives for services of 74 years.

At this point I'm pretty convinced that the company's depreciation rates are excessive. I conducted one more analysis based upon the company's data request to me. This, I must admit, was after I had filed the direct testimony. It's contained on page 2 of Exhibit 20. And here I've compared the company's current average service lives to industry statistics.

COMMISSIONER WEFALD: You're on which page?

THE WITNESS: Second page of 20.

COMMISSIONER WEFALD: The second page?

THE WITNESS: Yes. And I obtained these statistics from the AGA/EEI. They are proprietary and confidential so I've only summarized them here. But if you look at, again, mains, the company's average service life is 36 and you look across that line and it's basically much lower than the industry

averages. And services is about five to six years lower than the industry averages. Given all that, I mean, I could have recommended longer lives, but I did not because there's a bigger issue in depreciation.

As I indicated, I'd like you now to go back to 4, Exhibit MJM-4. On that first page you can see at the bottom of the page where it says total depreciable plant, the first column is, of course, the description of the plant accounts. The next column is plant balance, and the next column is the cost of removal or the negative net salvage that's incorporated in the current depreciation rates. And that happens to be $46.5 million. Now, that's the total estimates back at that time. That, again, is about almost 50 percent of the total plant balance. What that means is, that in calculating those rates, those depreciation rates, an additional 50 percent was added to the plant balance in order to collect 150 percent of the plant balance.

So -- and that might be reasonable. I did some more investigation. And what I discovered -- I'm going to point you again back to that 140 percent for services, because that is a huge rate, and the resulting depreciation rate of 8.22 percent

is the highest rate I think I've personally seen for a gas service account. It's way -- very much higher than normal. So I asked for the company's actual net salvage data and what I discovered is shown on my Exhibit MJM-6. And what that shows --

COMMISSIONER WEFALD: Just one moment, please.

COMMISSIONER REINBOLD: What are we looking for?

COMMISSIONER WEFALD: MJM-6.

THE WITNESS: MJM-6. What that shows is that on the gas side, the total net salvage for the years 1997 through 2001 was 1.4 million.

COMMISSIONER WEFALD: Where do you see that?

THE WITNESS: Where it says total under net salvage, natural gas.

COMMISSIONER WEFALD: Okay.

THE WITNESS: But what's really extremely interesting about that number is it's positive and the company is collecting for negative net salvage to the tune of about $2,000,000 a year in its current depreciation rates. Furthermore, in doing this investigation, I discovered that there apparently was a sale of a building in 2001 which

produced about 4.9 million, a 4.9-million gain that was a common plant. And the company included that also as positive salvage.

Now, Mr. Jeter wrote many, many, many pages of testimony rebutting me, but he never addressed this threshold issue, which is that the company's current depreciation rates are charging ratepayers about $2,000,000 a year for negative net salvage when the company normally experiences positive net salvage. And that difference is, in my opinion, even with the lives which I know are much too short, but that overcollection is what produces the excessive depreciation reserve levels.

I talked in my testimony about a certain new accounting requirement, Generally Accepted Accounting Principle. First of all, the acronym for that is GAAP, G-A-A-P. And I readily admit that GAAP does not control ratemaking. But what I find interesting about SFAS No. 143 are the principles which underlie it, and I believe they make sense and I'm just recommending to you to consider those principles. The principles are fundamental. Before you include any cost in today's cost for some future potential expenditure relating to the removal of a plant or mass property plant, you have to establish

a legal obligation to incur that cost. Otherwise, that cost will just be expensed as incurred, rather than used to inflate depreciation rates.

Now, Mr. Jeter has included a lot of testimony about how to implement FAS 143, but he failed to focus again on the fundamental issue, which is does this company have asset retirement obligations, those legal retirements. And the answer is based upon all of the responses that were submitted to me is, the best answer is they don't know, but I think the most likely answer is no, based on what I'm finding out in other states and in other proceedings. The natural gas industry does not have asset retirement obligations for distribution plant. And if they do, they're rare. There are some unique circumstances involved.

So what's going to happen as this company is subject to SFAS No. 143, just like all companies in the country, regulated and unregulated. And what's going to happen is that on their nonregulated books when SFAS No. 143 is implemented, all of that excess depreciation which is included in the distribution plant reserve reflected by that 70 percent is going to be pulled out of that reserve and treated as a regulatory liability to ratepayers.

So the company has said they are going to do -- they recently embarked on a new depreciation study. I don't know how that's going to be treated there. My suspicion is, you know, if I were involved in that study, I'd say for ratemaking purposes, perhaps you ought to use the remaining life method which will amortize that excess back to ratepayers over the remaining life of the existing investment.

But what I've done for the purposes of this rate case, since clearly their current depreciation rates are excessive as a result of this negative net salvage is, I've merely eliminated from the existing depreciation rates. I haven't changed any of the lives or anything like that. I've just stripped out the negative net salvage and said let's collect that, the average of that on sort of a normalized expense basis. This is a procedure that is used in Pennsylvania regularly. It's been recently approved in two cases in Kentucky. In my opinion, it is consistent with the likely result.

COMMISSIONER REINBOLD: With what?

THE WITNESS: It is consistent with the likely result of the implementation of SFAS No. 143, combined with another statement of accounting policy on property plant and equipment. It keeps the

company whole. It keeps ratepayers whole and it removes this excessive recovery from current depreciation rates. I talked a lot about depreciation because, of course, it's the biggest adjustment in my testimony.

I'm also recommending the elimination of wages and bonuses. I'm recommending the elimination of the supplemental security income plan. I'm recommending a five-year rather than three-year rate case amortization period, and the disallowance of inflation to other O&M expenses.

That concludes my summary.

MR. HOBERG: Mr. Binek, did you have some questions?

MR. BINEK: Yes. I just have a clarification concerning the statement about elimination of wages and bonuses.

Q. (MR. BINEK CONTINUING) When you talk about the elimination of wages and bonuses, what -- is it your recommendation that the -- you eliminate the 2003 increases as an expense in this proceeding? You're not telling the company that they can't give raises or bonuses, if they want to, it just should not be charged to the ratepayers?

A. That's correct. Elimination from the rate

case.

Q. Right.

MR. BINEK: Okay. At this time I'll tender the witness for cross-examination.

MR. HOBERG: Thank you, Mr. Binek. Mr. Pearce, please.

MR. PEARCE: Thank you.

CROSS-EXAMINATION

BY MR. PEARCE:

Q. Mr. Majoros, I may have misheard. I was a little alarmed when you said elimination of wages. I don't assume you mean all wages to employees should be taken out of the rate case?

A. Not all.

Q. Now, to clarify a point that may be misleading, you talked about the Lindheimer, Illinois Bell case and cited the Court's reference to confiscation being the issue. What the Court is talking about, isn't it, is that Illinois Bell alleged that its property was being confiscated by exceptionally low rates? It isn't a matter of the other side claiming that the depreciation rates were confiscatory?

A. Well, I believe you're probably correct, but the words stand on their own.

Q. Yeah. It's sort of a pejorative word. I just didn't want it to be taken out of context.

A. But I heard that word this morning. That's the only reason I brought it up.

Q. Turning to your Exhibit 20, and this is page 1 of 4 of MJM-5, which is your geometric mean turnover analysis for the mains account. You described your technique using the geometric mean for a life estimate there and, of course, a geometric mean uses a product of two ratios there, doesn't it? You take the square root, of course, the usual way the geometric mean is done. That technique means -- now, for example, if you -- looking at, say, 1996, for example, if you substituted; that is, interchanged columns C and D, the additions and retirements, you'd have the same result, right, because they both appear as numerators in effect in that calculation so it doesn't matter how you take them? In other words, you would get the same lifetime if you had single-year retirements of 119 -- I mean, single-year additions of 119,000 and single-year retirements of 1,096,000, you interchange columns C and D, is what I'm saying and you get the same number?

A. Yes.

nonexistent. Now, you're not suggesting, are you, that they were not in their day a highly reputable and very large company?

A. I just -- when I talk about them, I'd like to be looking at their study. Yeah, they were a large company in their day.

Q. For whatever reason, I believe they have, in fact, disbanded or disappeared. You have not done an actual depreciation study, a full study comparable to their 1991 study, have you?

A. You know, I'm not really sure of everything they did in that study. I know what they said they did. I've tested the lives of the two largest accounts in the company's books, and if I could refer you to the Stone & Webster study, I have it here before me. I'll just refer you to page 4. I used the geometric mean turnover approach to test that. And in the Stone & Webster study they say in the second paragraph, quote, The turnover testing is a procedure in which the adjusted turnover period, i.e., the number of years it takes an investment in plant to be retired, is determined by aggregating additions from the year 1991 backward until the total is equal to the plant balance in that year and then adjusting for the rate of growth in the

then adjusting for the rate of growth in the account.

So, you know, turnover method is not new. Other firms have used it. And I'm not recommending any changes in service lives.

Q. You're not suggesting the way you characterized it a moment ago that Stone & Webster didn't actually do what they said they did?

A. Well, I don't know how they arrived at the negative 140 percent for services and you can't tell from that study.

MR. PEARCE: Okay. I don't have any other questions.

MR. HOBERG: Thank you, Mr. Pearce.

Commissioner Reinbold, did you have any questions in there?

COMMISSIONER REINBOLD: Just a couple. Thanks.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. I lost track of something here. The 1991 Stone & Webster survey, what was the point that you were making about that?

A. Well, the first point is it's 11 years old. The second point -- the point I just made was, they

apparently employed one of the very procedures that I've used here to test lives in that study. And the reason I bring that up is because Mr. Jeter and now Mr. Pearce have sort of implied that I haven't done any kind of complete study, whether it's -- you know, given the level of available data, the use of the geometric mean turnover approach is as legitimate as any other approach.

Q. Okay. Turning to your reference to selling a building, can you flesh that out a little bit?

A. Yes. There apparently was a building sold in 2001 and it produced a gain of about $5 million. And the company debited cash, put that money in cash and credited it to accumulated depreciation. Now, if that building was included in rate base, which I imagine it probably was, that gain probably ought to be shared with ratepayers. By using the company's approach here, you would not have known about it until I found it.

Q. I understand now.

COMMISSIONER REINBOLD: That's all.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald, please.

COMMISSIONER WEFALD: Yes.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. On page 5 of your testimony you say the compound growth rate from 2000 to 2003 is 5.7 percent and you have a chart, an exhibit that reflects that. I think it's Exhibit MJM-2.

A. That's correct.

Q. Okay. What specifically do you think is driving this?

A. I think that commissions and bonuses and the SISP and the imputation of inflation in year 2003 are driving this.

Q. On page 10, why are the company's depreciation reserves so high? I need to have you help me with this. It's negative 140 percent factor on line 8, which means that the current depreciation rates for service was substantially increased to recover not only the existing investment, but also another 140 percent for future costs of removal?

A. That's correct.

Q. So I just need an example here. When they put in a gas main, the current depreciation rate is -- according to your understanding, it doesn't recover not only the existing investment to the main, but another 140 percent for future cost of

removal of the main?

A. Here I'm talking about services, which --

Q. Services.

A. -- is from the main to the house. And if it costs $1,000 to put that service in, its depreciation rates were designed to collect $2,400, which was the original cost plus another 140 percent for future cost of removal.

Q. What do you -- if you have looked at other depreciation studies, what would you say would be a more normal future cost of removal?

A. Well, typically, that number is driven, based from my experience, is typically driven by some internal cost allocation policy in which the cost of removal is -- you know, they have to figure -- when they go out and replace a main and a service, they have to figure out how much of that cost they want to assign to cost of removal. So they come up with an allocation factor, which results in that allocation.

I explained in my testimony here about Elizabethtown Gas. This was just, you know, within the last two months where I went out and watched a typical main replacement project for that company. And what I discovered in watching and observing that

project, was that the replacement of an existing service, first of all, is very rare. It's a --

Q. You mean the part from the main to the home?

A. Right.

Q. That's the service?

A. That's the service. Because what they do is, they'll have a main running down a street and want to replace that main. They will trench a couple of feet away and a lot of times they will keep that existing service. They may insert something into it to maintain, but it's rare that it actually gets removed. So the replacement cost is just the cost for disconnecting from the original main and then extending another tap over here.

So, in my opinion, that cost is really a replacement cost and probably ought to be capitalized to the new main or something like that. So it's difficult to answer your question about what is a typical removal cost. It depends on how a given company allocates that cost. What's important to understand about this particular company is they don't record any cost of removal at all for services. They're collecting 140 percent, but not recording any cost of removal, as difficult as that

is to believe.

Q. They're not reflecting any cost of removal where?

A. No cost of removal in their books and records. I went through their summary tables and I can see some cost of removal for mains. I could see -- I was looking for account 380, services, and it's not there. They're not recording any -- as big as that number is, you would think that that would certainly be one of their recurring costs of removal, they would record it, and it's not there.

Q. So does that suggest to you that they're not having any --

A. I don't think they do.

Q. -- costs of removal?

A. I speculated in my testimony and Mr. Jeter took, you know, a shot at me, but what I found out in the Elizabethtown Gas case is that for years and years and years that company and probably most gas companies, the people in the fields never recorded costs of removal. They treated everything as a service transfer expense and just expensed it.

Q. All right. Now I want to go -- all right. Now, I want to understand MJM-4.

A. Yes.

Q. You said another --

COMMISSIONER REINBOLD: What page is it on?

COMMISSIONER WEFALD: MJM-4. It's in the back of his testimony here. Page 1 of 2.

COMMISSIONER REINBOLD: Okay.

Q. (COMMISSIONER WEFALD CONTINUING) Now, on this one you said another 50 percent was added to the total depreciation plant.

A. Yes.

Q. That's down at the bottom.

A. Yes.

Q. I need you to lead me through that again.

A. First, the third column is plant balance.

Q. Right.

A. Okay. I always go back to services because it's the best example of this.

Q. It shows a negative in front of that 46. What is it, 46 million?

A. That's at the bottom. I was trying to lead you to how I got to that number.

Q. Okay.

A. So if we look at services, the plant balance is $200,727,046.

Q. All right.

A. The company applied a negative 140 percent

salvage ratio to that to come up with an estimated future negative -- future cost of removal of $28,101,844. It added that amount to the plant balance to arrive at something called the estimated service value, which is $48,174,590.

Q. Where is that number?

A. That is under a column titled estimated service value.

Q. All right.

A. Okay. It then divided that estimate service value over the estimated remaining life of 21.8 years. That's about the third from the last column.

Q. Yes.

A. To come up with an annual accrual amount of 1.6 million, which in turn produced an annual depreciation rate of 8.22 percent, which is then applied every year to calculate depreciation expense and, in fact, the company applied that rate to services in this case and, of course, the plant balance -- this was the 1989 -- 1991 plant balance. That has increased, I believe, substantially. So in this case, the recovery is more than that.

So, anyway, going back to that column where they've applied the 140 percent, they also applied

negative 40 to mains and then they have some positives offsetting it, but the sum of all those positives and negatives sums to negative 46,495,732, which, again, you can see has been added to the plant balance to arrive at that estimated service value, which is then being depreciated.

Q. All right. Thank you. All right. Then go to MJM-6.

A. Yes.

Q. Now, you made the point and I just -- is this what you said, that MDU is charging customers negative net salvage when the company has a positive salvage value?

A. Yes.

Q. So the $2,733,666, tell me about that number again.

A. What I've done there is you'll notice I've separated the plant into electric, natural gas and common utility.

Q. Yes.

A. The common utility I didn't know exactly how to allocate that back to the electric and natural gas, so what I did was allocate that 5.5 million back to electric and gas based upon the totals right above that, you know, the 1.412 and the

1.44. The sale of the building is included in that common utility plant column. I mean, the gain on the sale of the building.

Q. The sale of the building is included in which column?

A. Common utility. It's the first big number on that, over in the right-hand column, the 4.889 million.

Q. I'm somehow missing that.

A. All the way to the right.

Q. All the way to the right. I'm seeing the number -- am I looking at the correct number under common utility, 5,529,260?

A. Right. At the top of that column.

Q. All right.

A. That's the gain on the sale of the building.

Q. Oh, that 4,889,037?

A. Yes.

Q. Okay. Then I need you to go to MJM-1.

A. Okay.

Q. And this gives -- page 2 of 4.

A. Yes.

Q. This goes over the numbers. You're contrasting your numbers to the company's numbers

and its income statement?

A. Yes.

Q. And at the present time, let's skip over the operating revenues --

A. Okay.

Q. -- because those are the same?

A. Yes.

Q. And then you go down to the operation expense, and there isn't a difference in your cost of gas, there's a slight difference in your other O&M?

A. Yes.

Q. But the big difference then comes when you get to depreciation?

A. Yes.

Q. And the company is projecting in 2001, 2002 and 2003 over $3 million, but let's use the 2003 figure because that's the one you're looking at also.

A. Mm-hmm.

Q. Is that correct, $3,261,000?

A. Yes.

Q. And you're projecting $1,089,000?

A. Yes.

Q. So you're right. This is a big ticket

item. So I need to have you tell me how did you come to that $1,089,000 versus the $3,261,000. Where would I see what you've done to make the difference here?

A. It's in my Exhibit MJM-7.

Q. All right.

A. Page 1 of that exhibit is the company's current depreciation rates without the negative -- without the net salvage built in. I've stripped out, you know, the 140 percent and those numbers we were looking at in that column.

Q. You've stripped out all of that or only the one for the services?

A. All of them.

Q. You stripped out all of them?

A. Yes.

Q. Did the company show any cost for some of those, to remove some of those?

A. Yes. They have costs to remove some, but overall the cost has been positive as shown on Exhibit MGM-6.

Q. And that's because of the building being added in?

A. No. The building is separate. That's in common utility. The natural -- on the natural gas

side, for the last five years, setting aside common, setting aside electric, the actual net salvage experience for the company has been positive every year.

Q. All right. So those positive numbers mean that there's a positive -- that it is a positive cash flow, doesn't mean that its cost -- when the first one says 440,703 --

A. Mm-hmm.

Q. -- in 2001, that means that that's a positive number, there were no costs that the company incurred?

A. That is a net positive number. Net pluses and minuses.

Q. So they had some costs, they had some money that they showed from what? Income from what?

A. I don't know. Probably is some reuse involved in that. Let me see. It seems like the company is obtaining a fair amount of positive salvage on underground conductor and devices, which, you know, I don't know if they are selling them or reusing them. So that's one source. I'm sorry. I'm looking at the records.

Q. Okay. Take your time.

A. I was having a disconnect there. What the

mains. I'm just looking at 2001.

Q. That means they will sell gas mains?

A. I don't know. I don't know what the source is. Power operated equipment could be reused. Bottom line, I don't know all of these things. I do know that it's been positive, net positive.

Q. All right. And so you added up those net salvages on the natural gas and it came to 1,444,452?

A. Yes.

Q. And is that what you subtracted then from -- then we still have a different number from their 2003, 3,261,000 and your 1,089,000. What's the number?

A. I stripped out the negative salvage -- all the salvage ratios from the depreciation rates themselves. And in distribution plant that resulted in a 2.37 percent composite depreciation rate rather than the company's existing depreciation rate. The next thing -- so I applied the rates without the net salvage allowances to the plant balances, which is the way it's done in the rate case, and then to that total I subtracted the average positive salvage that the company has experienced in the last five years, including the gain on the sale of the building. If

the company had regularly experienced negative net salvage, I would have added, you know, one-fifth of that amount to the annual depreciation expense.

And, again, the average net salvage is $848,010 shown at the bottom of MJM-6, page 1.

Q. Right. And then you did what with the sale of the building?

A. I included that in that average annual experience amount.

Q. Over five years?

A. Yes.

Q. To give the ratepayers a credit --

A. Yes.

Q. -- for that? And that's how you came up with the Snavely King $1,089,000?

A. Well, the Snavely King $1,089,000 is shown ultimately on Exhibit MJM-7, page 3.

Q. All right.

A. Up above it says company proposal, 2003. Those numbers show the application of the company's depreciation rates to plant balances of the sum $3,261,000 that they're proposing. And below shows the application of the depreciation rates without the net salvage built into them to the same plant balances. That sums to $1,937,000, from which I

balances. That sums to $1,937,000, from which I subtracted the average annual net salvage of $848,000 to arrive at my recommended $1,089,000.

Q. Thank you. Now, the current income taxes, we haven't heard anything about that and yet I notice that that's also a substantial difference in the amount.

A. Are we --

Q. Page 2 of 4 of MGM-1.

A. Yes. Current income taxes, I've used the same procedure as the company to calculate that amount and that amount -- that calculation is shown on page 3 of 4 of Exhibit MJM-1.

Q. And your calculation shows 500 -- a charge of 529,000; is that what the negative --

A. That's a negative current income tax expense. And the reason for that has something to do with the deferred fuel lag, I think, the lag and the recovery of deferred gas expense resulting from the PGA.

Q. Help me interpret the negative number. I'm sorry. I'm having trouble with that. The negative number means that just -- is that something they will pay or they won't pay? I see a positive number of 4,322,000 in current income taxes that they are

going to pay in 2001. Does that mean they are actually going to pay 4,322,000 in 2001? I'm looking at MJM-1, page 2 of 4.

A. I don't know. My suspicion is they didn't pay that --

Q. All right.

A. -- as a result of all kinds of timing differences.

Q. But the next number means that they would have a credit of $3,067,000, is that what that negative -- is that what the parentheses mean?

A. Yes. And it has to do -- again, it has to do with the interrelationship of the PGA and deferred fuel balance.

Q. And the next number means that they would also have a credit of $1,961,000?

A. That's what -- yes.

Q. So the number that you're showing as a credit of $529,000 is actually less of a credit than what the company is showing to the ratepayers?

A. Yes, because I'm showing more income than they are so I have less of a tax credit than they do.

Q. You're showing more income than they are?

A. Net income before taxes.

COMMISSIONER REINBOLD: Mr. Hearing Examiner, if we are not going to finish off this witness tonight, let's wait until morning.

MR. HOBERG: I think perhaps we're close.

COMMISSIONER REINBOLD: Are we close?

MR. HOBERG: Well, we only have Commissioner Wefald, Commissioner Clark and perhaps not very many questions. Mr. Diller has a couple.

COMMISSIONER REINBOLD: Okay. You're the Hearing Examiner.

MR. HOBERG: I think maybe, if we can, finish it off in just a few minutes.

Q. (COMMISSIONER WEFALD CONTINUING) If I can just understand that number, then I'm done. All right?

A. The negative current tax number. Every time I come to North Dakota I get one of these.

Q. Maybe Mike Diller can explain it to me, but I better ask you. Why you're showing that it should be a smaller credit for the customers than the company does?

A. Because my net income before taxes, what I estimate for 2003, is higher than the company's. That's one reason why my recommendation is for less of an increase. I'm recommending a decrease.

Q. All right.

A. So the more net income before taxes that you estimate, the less current taxes -- no. The more current taxes you would have. And we're dealing with negative numbers here because I'm estimating more net income. I'm estimating more current taxes, which is less of a credit than the company.

COMMISSIONER WEFALD: All right. Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, please.

COMMISSIONER CLARK: Just a couple questions.

EXAMINATION

BY COMMISSIONER CLARK:

Q. The 140 ratio, maybe you mentioned this, but I'm not sure that I picked it up. Now that I understand the math better, again, how is that arrived at for, you know -- and I know you didn't have access to the information that the consulting firm that did it back in the early '90s. But typically how would that be figured and what input would go into figuring that 140?

A. Typically, the way it's done is, in the

depreciation studies that I've been involved in, there are typically tables that show annual retirements by year, then gross salvage by year, and cost of removal by year. And the net of those gross salvage and cost-of-removal numbers are related to the retirements to arrive at these ratios.

Now, there's all kind of problems with that approach to the analysis, but that's the way it's typically done, or has been typically done. I look through the Stone & Webster study and I don't see any of those kind of analysis, so I don't know -- you know, I do know that in that study it said to the extent such data, net salvage data was available. I think it's quite possible that it was an off-the-top-of-the-head estimate because the company doesn't record any net salvage for services.

Q. So your recommendation is because it's a positive number, it should just be sort of zeroed out?

A. No. I'm recommending we abandon the procedure entirely and take -- because the new thinking in the accounting profession is that if you don't have a legal obligation to incur that kind of cost on a long-life asset, you probably should expense it or perhaps, in my opinion, capitalize it

to the replacement. Most of these things -- in this we're dealing with mass property plant here. We're not dealing with power plants or nuclear plants. We're dealing with services and mains that get turned over all the time. There's constant activity. They have blanket work orders to do this kind of work. And that to me looks a heck of a lot more like an annual operating expense than something you should treat as a capital cost to inflate depreciation rates. On the other hand, you treat it as a replacement cost and capitalize it.

Q. Now, that is starting to get into the point about the AROs or asset retirement obligations and that gets into the SFAS No. 143. Okay. Let's assume that in college I was reading about the Civil War --

A. Yeah.

Q. -- as opposed to GAAP. Can you give me some examples of, you know, in a concrete way what this ARO means? I understand it is talking about incurring legal obligations. But what -- kind of lay out a couple of examples of what would be an actual obligation.

A. I think that one that pops in is the retirement to remove a nuclear plant and that's

going to cost some money. So what -- and there may be a legal requirement to remove any kind of electrical plant, although I'm not sure.

COMMISSIONER WEFALD: Or gas plant.

THE WITNESS: Maybe a gas plant, manufactured gas plant or something like that. But if there is, what this thinking says, if there's an obligation -- normally when you buy a gas -- say, you buy a manufactured gas plant and it costs $1,000, you debit gas plant, that's plant in service, and you credit a liability, long-term debt or cash or something, but you have something. So the cost of that plant is $1,000. The rationale that underlies FAS 143 is that if you have a legal obligation to then remove that plant, say you estimate it would cost you $200 to remove it and you have a legal obligation to do that, then that is part of the cost of the plant so it gets capitalized as $1,200. But you don't do that unless you have a legal obligation to incur that cost. If you don't have a legal obligation to incur that cost, and this is just replaced as normal things do, you probably would expense that cost.

COMMISSIONER CLARK: Okay. That's all I have right now. Thank you.

MR. HOBERG: Thank you, Commissioner Clark. Mr. Diller, do you have some questions?

MR. DILLER: I hesitate to ask a question. Commissioner Reinbold looks like he's ready to leave.

COMMISSIONER WEFALD: We could maybe wait until tomorrow morning.

MR. DILLER: I don't have that much. It's real general.

MR. HOBERG: Any further questions then of Mr. Majoros?

COMMISSIONER WEFALD: I don't want Mr. Diller to not ask questions.

MR. BINEK: I'm going to have a couple of short questions. I mean, they shouldn't take but a couple minutes.

MR. HOBERG: Is yours pretty short, Mr. Diller?

MR. DILLER: Yes, it is.

MR. HOBERG: Commissioner Reinbold?

COMMISSIONER REINBOLD: You're the Hearing Examiner.

MR. PEARCE: I have one question, if I may, at some point, too.

MR. HOBERG: So we have four questions left

of Mr. Majoros. He's going to be back tomorrow, isn't he? Let's recess tonight and finish in the morning.

(Recessed at 5:04 p.m., the same day.)

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
Montana-Dakota Utilities Co.	)	CASE NO.
Natural Gas Rate Increase	)	PU-399-02-183
Application	)	

TRANSCRIPT OF HEARING

State Capitol
Commission Hearing Room
Bismarck, North Dakota
October 8, 2002

Before Allen C. Hoberg
Hearing Officer

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(The following proceedings were had and made of record, Monday, October 8, 2002, commencing at 9:00 a.m.)

MR. HOBERG: Let's go on the record. This is day two of the hearing in the matter of the application of Montana-Dakota Utilities Company for a natural gas rate increase. Yesterday we concluded -- almost concluded -- we did conclude the direct examination of Montana-Dakota Utilities and we're taking the direct testimony of the staff's case, and we have concluded Mr. King and we're almost, I think, done with Mr. Majoros.

Is there anything we should discuss preliminarily before we finish the testimony of Mr. Majoros today?

COMMISSIONER REINBOLD: I have to leave by 5:00 today.

MR. HOBERG: Hopefully, we're all able to do that. All right. Then I think --

MR. BINEK: Just one point. Yesterday Mr. Pearce or someone from MDU had indicated that one of their witnesses needed to leave early.

MR. PEARCE: That's no longer the case. I'm sorry. I forgot to mention that to you. We have no constraints anymore.

MR. HOBERG: I think when we get done with Mr. Majoros, we'll pause briefly and talk with counsel about what we're going to do in regard to rebuttal testimony, the order. I know you handed out a sheet here, and then mark your exhibits. It's a little bit different format for the exhibits for the rebuttal here, so the Court reporter -- we'll take time to mark those with the Court reporter. That will just take a couple minutes, though, I think.

All right. I believe we had concluded the Commissioners' questions of Mr. Majoros. So, Mr. Binek, did you have any additional questions of Mr. Majoros?

MR. BINEK: I do, but I think that you were at Mr. Diller.

MR. HOBERG: Was I at Mr. Diller? I'm sorry. Okay. Mr. Diller, please.

EXAMINATION

BY MR. DILLER:

Q. Good morning, Mr. Majoros.

A. Good morning.

Q. The depreciation issue is fairly huge in this case. It looks like it's $2.2 million of the difference between the company and staff position

and so I've got a few more questions on depreciation.

Maybe we could just start first by if you could answer this question. If we were -- if the Commission was to adopt your position, how many years would it take for the depreciation reserve to straighten itself out?

A. I would -- to answer that -- I can't give a precise answer to that question. But I would say if you adopt what I'm recommending here, which is to eliminate the negative net salvage from the company's depreciation rates, which would reduce those rates, and then amortize the positive net salvage that they've experienced, including the gain on the building over five years, that, combined with normal plant growth, should start to resolve that problem in about five years, I would think. Would be well on its way to resolving itself.

Q. So in your mind this wouldn't be a fix that would straighten itself out over one year's time, it would take a number of years?

A. Yes.

Q. And you're guessing maybe five years?

A. I'm guessing five years for it to make a significant dent. It will never resolve itself

entirely until, you know, all of the assets are fully depreciated and that would generally be over the average remaining life of these assets.

Q. The difference is so big between the parties I was just wondering -- I mean, if the Commission decided that it wanted to end up somewhere in between, would it matter whether the differences were resolved over five years' time or 10 years' time or 15 years?

A. No. What the Commission -- you know, the Commission could also recalculate rates with new service lives and calculate remaining life rates and then that resolution would be probably longer than five years.

Q. Can you tell me why depreciation is such a big issue here philosophically? I mean, why does the company care whether we use $1 million worth of depreciation expense or $3 million of depreciation expense? Forget about that expense is supposed to match revenues, expense is supposed to match the customers causing the cost, but philosophically, why would the company care one way or the other?

A. Probably because it represents pure cash flow to the company. The more depreciation that's charged, the greater the free cash flow flowing into

the company. Any reduction to that amount is a reduction in cash flow.

Q. Would there be any benefit if the state were to go to, let's say, retail wheeling or some kind of electric reform where it wasn't under rate-of-return regulation, would it be beneficial to have your plant assets depreciated more than is necessary at that point in time or less than is necessary?

A. Well, at that point in time, I think that if I were running the company, I'd want the correct depreciation rates.

Q. You'd want the correct ones?

A. Yes.

Q. It wouldn't be beneficial in a competitive environment --

A. No.

Q. -- to have your assets overly depreciated?

A. No, because in a competitive environment, depreciation does not drive cash flow. It's only in a regulated environment that depreciation drives cash flow because it's built in as a component into the price that's being charged to ratepayers. In a competitive environment, depreciation is an after-the-fact entry on the company's books. Prices are set by the market in a competitive environment.

Q. Okay. So in your mind it's all about cash flow?

A. In this case, yes, that is correct.

Q. Okay.

A. It's all about cash flow and the correct theory and rates.

MR. DILLER: Right. I think that's all the questions I have.

MR. HOBERG: Thank you, Mr. Diller.

Mr. Binek, did you have some more questions of Mr. Majoros?

MR. BINEK: Yes, just a few.

REDIRECT EXAMINATION

BY MR. BINEK:

Q. Mr. Majoros, should ratepayers have benefited from the gain in the building sale?

A. Yes.

Q. How should that gain have been reflected in depreciation?

A. Probably under the existing procedure should have been reflected in depreciation as a positive net salvage ratio in the structures and improvements account.

Q. Was it, to your knowledge?

A. No, it was not.

Q. Okay. What salvage value did the company apply to account 390, that's general plant structures and improvements?

A. If you turn to my Exhibit MJM-4, page 2 of 2, which is common plant, general plant, the building I think was included in account 390, structures and improvements, and you can see that that was depreciated using a negative 10 percent net salvage ratio.

Q. What are the advantages or disadvantages of extending the time period for correcting the depreciation as you have proposed?

A. What are the advantages or disadvantages?

Q. Yeah.

A. To whom?

Q. For the ratepayers.

A. Well, I would say for the ratepayers the advantages of going with my proposal is we get that reserve situation resolved quicker rather than later.

Q. Does it result in lower rates?

A. Yes.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek. Mr. Pearce, did you have some additional questions?

MR. PEARCE: No. No, I don't.

MR. HOBERG: Thank you, Mr. Pearce. Any further questions then of Mr. Majoros at this time?

COMMISSIONER WEFALD: I have one.

MR. HOBERG: Commissioner Reinbold, please.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. Yes. Mr. Majoros, review for me again when you say small interruptible customers are being overcharged, how, when and why. You said that, didn't you?

A. No, I think Mr. King said that.

Q. Oh, okay. I'm long behind in my notes.

A. One reason they're being overcharged is probably too much depreciation is flowing into their rates.

Q. Okay. I'll take that for now. And I understand the term, but I want to hear you define the phrase "cash flow," in your mind.

A. Cash flow?

Q. Yeah.

A. As I'm using it here it means cash flowing from ratepayers into the company without any corresponding cash outflow. Arrives at the company -- if we talk about labor expense, cash

flows into the company from ratepayers, but there's an offsetting cash outflow, so there's zero cash flow impact of that being included in rates. But with depreciation, cash flows in and there's no corresponding cash flow out, so it's there, stays there for the company's use for whatever it chooses.

Q. So then it becomes a balancing act?

A. Not in my mind, no.

COMMISSIONER REINBOLD: Okay. That's all I have then.

MR. HOBERG: Thank you, Commissioner Reinbold. Commissioner Wefald.

COMMISSIONER WEFALD: On -- well, I guess this relates to whether I'll have a chance to ask a question of staff after we hear the rebuttal of MDU. If I won't have a chance, then I would ask now. But if I will, then I would wait.

MR. HOBERG: Whether he's coming back on as surrebuttal?

COMMISSIONER WEFALD: Yeah.

MR. HOBERG: Mr. Binek, do you intend to call these witnesses, Mr. King and Mr. Majoros, after the rebuttal of MDU?

MR. BINEK: It's going to depend on what the rebuttal of MDU is. Ordinarily, we would not,

but if there's some new evidence that comes in, for instance, we would probably want to rebut that.

COMMISSIONER WEFALD: Should I just ask my question now?

MR. HOBERG: Well, Mr. Pearce, it sounded like yesterday you were expecting them to be called back on.

MR. PEARCE: No.

MR. HOBERG: You weren't. Oh.

MR. PEARCE: I certainly wasn't. I would be quite surprised. In fact, I hope it won't just go on forever and forever that we would have another surrebuttal on the surrebuttal.

MR. HOBERG: Perhaps ask it now then.

COMMISSIONER WEFALD: Then I'll ask my question now.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. On page 17 of Mr. Jeter's testimony he says --

COMMISSIONER REINBOLD: What page are you on?

COMMISSIONER WEFALD: Page 17 of Mr. Jeter. That's in this book here, in the rebuttal testimony.

Q. (COMMISSIONER WEFALD CONTINUING) The

paragraph starting with line 4, the question and then it goes through line 12. "Included in this discussion --

MR. HOBERG: Commissioner Wefald, excuse me. He needs a chance to find it here.

Q. (COMMISSIONER WEFALD CONTINUING) It's in the rebuttal testimony and exhibits. It says, "Included in his discussion of salvage on page 12 of his testimony at lines 1 through 2, Mr. Majoros says, it appears that the company has not recorded any net salvage at all for services; is that true?"

"No. I understand from company personnel that the company has recorded 1.4 million of net negative salvage for services during the years 1995 through 2001. Mr. Majoros took his data from a report of retirement work in progress, which because of the use of blanket work orders show services combined with mains. That is apparently the reason he concluded there was no net salvage applicable to services."

Yesterday I remember that you said that there was no net salvage applicable to services. Did you get your information from this report of retirement work in progress?

A. I got my information from the company's

response to my data request to provide all net salvage for even back prior to 1995, and it may be that they provided a blanket work order or this retirement work in progress material in response to that. But I can tell you that material clearly shows various accounts on it and the one that is strikingly missing is services. So for the company to say that it has recorded 1.4 million of negative net salvage for services, they haven't proven it to me. At this point everything I have says they didn't record any net salvage for services. And I'm responding based upon the information they provided me. Mr. Jeter makes this statement, but there's not a document to support it in his testimony or exhibits.

Q. When you requested the information from MDU, what did you ask for? What did your data request say?

A. My data request No. 21 referenced statements A through F, G through L, N through O, and those are the company statements. Question, Please provide annual North Dakota gas utility gross salvage and cost of removal by plant account beginning in 1986 through 2003.

Response, Please see Attachment A. For the

years '86 through '94, the information is available for the total company only. For the years 1995 to 2001 show both -- the years 1995 through 2001 show both total company and as allocated to North Dakota. Please see Statement O, pages 5 and 6, for salvage and removal costs for projected 2002 and 2003.

And this material I got, here is the -- I guess it's the retirement work order document that Mr. Jeter is referring to. If you want to take a look at it, you can see that it has account numbers and accounts, but one account that is missing is 381. There has not been -- I mean, 380, services. There has not been any net salvage recorded from 1995 through 2001 for services.

Q. Do you want to have that entered into the record?

A. Sure. It will be the response to data request 21. I have it here. I don't know if I have all of it. I mean, I took the pages that I relied on.

MR. HOBERG: Do you have a copy of that, Mr. Binek?

MR. BINEK: We should have a copy.

MR. HOBERG: Let's go off the record.

(Discussion off the record.)

MR. HOBERG: Let's go back on the record. We're going to mark the data request 21 as Exhibit 21 for the record. Did you have any further questions, Commissioner Wefald?

COMMISSIONER WEFALD: No.

MR. HOBERG: Thank you. Any further questions by the Commissioners of Mr. Majoros? Any further questions by any of the parties of Mr. Majoros? Thank you, Mr. Majoros.

MR. BINEK: Off the record, please.

(Exhibits 22, 23, 24, 25, 26, 27, 28, 29, and 30 were marked for identification.)

MR. HOBERG: We're ready to go back on the record. We're back from a short recess to mark exhibits, and I believe we're at the point where Montana-Dakota Utilities will call their rebuttal witnesses, starting with Mr. Jeter; is that correct?

MR. PEARCE: Yes, it is.

MR. HOBERG: Okay. Please call your next witness.

MR. PEARCE: I call John Jeter.

MR. HOBERG: Mr. Jeter, I don't think you've been sworn yet.

THE WITNESS: No.

MR. HOBERG: Were you here yesterday --

well, let me give it today.

THE WITNESS: I was here. I heard it.

MR. HOBERG: But I should give it once at the beginning of the day, just to refresh everybody's recollection, and I'm required to do so by law, anyway.

Let me tell all the witnesses again that the maximum penalty for perjury in this state is a Class C felony, punishable by a maximum five years imprisonment, a $5,000 fine, or both.

Mr. Jeter, being advised of the penalty for perjury, do you promise to tell the truth in this matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce, please.

JOHN A. JETER,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Would you please state your name and business address?

A. John A. Jeter, 1304 South 185th Circle, Omaha, Nebraska.

Q. What is your occupation?

A. I'm a certified public accountant and self-employed consultant. I retired from full-time association with Arthur Andersen & Company in 1991 after over 37 years with that firm.

Q. What is the nature of the work you performed while you were there?

A. I was involved in examinations of financial statements, and to a much lesser extent in design and installing accounting systems. For many years I performed other financial and accounting consultation services for utility clients.

Q. Would you summarize your educational background and professional experience, please?

A. I'm a graduate of the University of Nebraska at Omaha, from which I obtained a Bachelor of Science degree with distinction in accounting in 1954. I was admitted to the Arthur Andersen & Company partnership in 1967. I'm a member of the American Institute of Certified Public Accountants and the Nebraska Society of Certified Public Accountants. In 1994, I was elected to the Board of Directors of Tucson Electric Power Company and became a director of its parent company, UniSource Energy Corporation, when it was formed. I retired

from the UniSource board and its subsidiary boards in May 2001.

In 1991 I began consulting on my own with utilities regarding accounting and regulatory matters. As is true in this case, I have also consulted in association with Zinder Companies, Inc., a firm that provides economic and financial consultation to regulated utilities.

Q. What experience have you personally had in the utility field?

A. I have participated in or been responsible for regular audits of financial statements, registration statements filed with the Securities and Exchange Commission, the SEC, for the sale of securities, installations of property records and information systems and a variety of other special accounting services for regulated industry clients. For many years before I retired from Arthur Andersen I had regional responsibilities for its regulated industries practice, and was a member of the partnership team that established policies with respect to issues facing clients in rate-regulated industries.

I often taught at both training sessions for Andersen personnel and in training sessions

Andersen offered for its clients and others. This training ordinarily involved accounting issues, tax issues, and various regulatory matters. In 1992, I prepared a paper and presented it twice in a tutorial sponsored by the Institute of Electrical and Electronics Engineers, Inc. Power Engineering Society. The title of my portion of the tutorial was, quote, Accounting for Depreciation, Return, and Income Taxes, unquote.

Q. Have you previously testified before any regulatory agencies?

A. Yes. I've testified before the Federal Energy Regulatory Commission, the FERC, and its predecessor, the Federal Power Commission, the National Energy Board in Canada, the Interstate Commerce Commission, and regulatory agencies in North Dakota and a number of other states, and the province of Alberta, Canada. My testimony has addressed depreciation, accounting for income taxes, post retirement benefits other than pensions, working capital, and various other topics related to accounting and ratemaking issues. I have attached Appendix A, which is a his of my testimony in regulatory proceedings since the beginning of 1996.

Q. What is the purpose of your rebuttal

testimony in this proceeding?

A. I've been asked by Montana-Dakota Utilities, paren, quote, Montana-Dakota, quote, or, quote, the Company, unquote, to respond to the direct testimony of Michael J. Majoros, Jr., on behalf of the staff of the North Dakota Public Service Commission regarding depreciation rates.

Q. I believe you are sponsoring Exhibits 22, your testimony, with JAJ-2 attached, and also Exhibits 29 and 30; is that right? Exhibit 29 we just marked.

MR. PEARCE: That's actually a page from Mr. Jeter's testimony. And Exhibit 30 is a summary of negative salvage from Montana-Dakota Utilities.

MR. HOBERG: Exhibit 29 is a page from his testimony?

MR. PEARCE: I believe that's what it is.

THE WITNESS: It's a new schedule that I prepared.

MR. PEARCE: It's a schedule. I have my little yellow thing on the wrong sheet. That didn't make too much sense, did it?

MR. HOBERG: So are you offering --

MR. PEARCE: I'm not offering yet. I'm just mentioning those are his exhibits; 22, 29 and

30.

Q. (MR. PEARCE CONTINUING) Will you please summarize your conclusions?

A. Yes. The company is using the depreciation rates included in Case No. PU-399-94-297 based on a depreciation study completed in 1992. Currently, Montana-Dakota has retained AUS Consulting to complete another depreciation study by December 31, 2002. There should be no change in depreciation rates until that study has been completed and the appropriate review has taken place as Mr. Majoros did not prepare a depreciation study, has not presented -- has presented no evidence that the depreciation rates should be changed at this time. A proper depreciation study will involve reviewing additions, retirements, transfers, balances, salvage, removal costs, and accumulated depreciation for the entire history of each account in gas plant and common plant for Montana-Dakota's gas distribution, none of which Mr. Majoros did.

Mr. Majoros' reference to cash flow as a basis of setting depreciation rates is completely incorrect and his use of the rough turnover estimation procedures is not reliable and is not used to measure depreciation rates when study data

is available, as it is in this case. His comments regarding net salvage are largely his unsupported opinions and are not based on any analysis of Montana-Dakota facilities, experience, or operations.

Q. Would you please describe the facilities being depreciated by the company?

A. Montana-Dakota's facilities include gas distribution properties in North Dakota that are used to serve approximately 83,500 customers in 76 communities. In addition, there are common facilities that are used in connection with the electrical gas operations in North Dakota and other states, the costs of which are directly assigned or allocated to the North Dakota gas operations.

Q. On pages 5 through 9 of his testimony, Mr. Majoros discusses a relationship between cash flow and depreciation. Is this a normal type of depreciation analysis?

A. No. Mr. Majoros states that depreciation is not intended to finance additions on page 6, lines 3 through 4, but then compares Montana-Dakota's companywide depreciation expense with the plant additions that were made during the years 1996 through 2001. It is well established that

depreciation is not intended to finance plant additions and the relationship between the two is largely meaningless for determining the appropriate time period during which the company's plant should be depreciated.

In spite of this, Mr. Majoros concluded at lines 25 to 26 at page 6 of his testimony that the company, quote, is financing all of its plant additions from depreciation funds it collects from ratepayers and still has a substantial amount of additional cash for other matters, end quote. There is no way he can support that conclusion, because he is assuming incorrectly that there are no other requirements for the cash flow.

Moreover, since depreciation is meant to recover the existing investment, it is irrelevant whether investors reinvest the recovered funds or, instead, find other uses for the funds. The appropriate depreciation rate is dictated by the need to recover the invested capital during the life of the facilities. By ignoring that fundamental purpose of depreciation, Mr. Majoros is effectively proposing that the depreciation rate should vary from time to time depending on the amount of cash the company is investing on projects deemed by

Mr. Majoros to be beneficial to ratepayers. Presumably, in years when the company has, quote, additional cash for other matters, unquote, Mr. Majoros would reduce the depreciation rate. Conversely, in years when the company needs to undertake major investments in plant, Mr. Majoros presumably would propose major increases in depreciation rates so that the company will have sufficient cash flow to fund all of its investments without borrowing, retaining earnings, or issuing common stock.

It is doubtful that Mr. Majoros really means to revolutionize the concept of depreciation so that customers' rates can be increased dramatically to provide financing for new investments. Nevertheless, that is the logical corollary to the new, quote, cash-flow-needs, unquote, standard for setting depreciation rates that Mr. Majoros is advocating.

Q. Is Mr. Majoros' assertion concerning Montana-Dakota's source and uses of funds factually accurate?

A. No. In addition to the fact that the comparison he made is meaningless, the amounts used are not comparable. The depreciation -- and I'm now

referring to his page 6. The depreciation in column 2 includes depreciation of common plant, but the amounts for, quote, construction/acquisition (sic) in column 3 do not include those for common plant.

Now, I'd like to insert here the fact that yesterday Mr. Majoros put forth Exhibit 20, and included in that exhibit is a schedule which is entitled page 6 table expanded. That's the top page of Exhibit 20. What he did there was to add the common plant construction in column 5, which is why it exceeds the amounts in column 3, and then show the corrected incremental cash flow. He could easily have left out columns 3 and 4 because they are obviously -- well, 3 is correct, but column 4 he could have left out because it's no longer correct and I think he would agree with that.

But I wanted to point out that he has now corrected that. During this 1996 to 2001 period there were 28,000 -- $28,064,555 of additions to common plant. This changes the incremental cash flow in his column 4 from $28,473,000 to $408,000. Now, with his expanded schedule, he comes to $409,000. So we differ again by rounding differently on that number by 1,000. The last year in the column and in his original table in his

testimony was shown as 2002 and should have been 2001, and he carried that into his expanded table. Mr. Majoros also -- excuse me. I've come to the next question.

Q. Mr. Majoros also made an analysis using just a North Dakota distribution and general plant additions and depreciation expense amounts in his Exhibit MJM-3. Is that any different?

A. No. It's also meaningless for similar reasons. Once again, his conclusion is completely incorrect. After observing that the depreciation expense for the years '86 through 2001 exceeded the plant additions by 4.5 million he says, paren, on lines 8 and 9 on page 7, close paren, quote, It seems that ratepayers rather than investors have been financing the company's North Dakota plant through excessive depreciation, end quote. Interestingly, he asserts that there is, quote, excessive depreciation, end quote, and has at this point in his testimony mentioned no basis for that other than the comparison of depreciation cash flows and plant additions, which even he agrees are not the basis for setting depreciation rates.

I'd like to insert here also based on his Exhibit 20. Well, let me first explain. The next

paragraph of my testimony I was planning to strike because it was incorrect. However, in Exhibit 20 he revised the Exhibit MJM-3 and in revising it, it's now incorrect. I said earlier that it was when it wasn't and now he's revised it and now it is, in fact, incorrect. And that's the third page in Exhibit 20. He added depreciation of common plant to the depreciation of distribution plant that was originally in his exhibit and that shows in column 2, increased amount there. But he did not add the common plant additions in column 3. Had he added them, I think the schedule would not show what he intended it to show.

For instance, in the first year, 1986, the additions, including common plant, are $2,699,841, compared to the 1,945,514 of depreciation expense. And, therefore, there would have been a negative number in the fourth column of 754,327. I didn't go through all of these to make that correction, but the only other one I did was in '89 and it has the same type of effect only more so.

COMMISSIONER WEFALD: Can you just repeat for me again which document you were looking at?

THE WITNESS: All right. His Exhibit 20 that was entered yesterday, and it's the third page

of that, ma'am, if you just turn back into it. It's several different things, and the third page is the one I was referring to.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: Yes. Now, that is supposedly the same thing as his Exhibit MJM-3, which was attached to his original testimony. And what he has done, if you look at the two, you can see that he has added amounts in column 2 each year so that the total depreciation expense instead of being $33,405,083 as it was in his original exhibit is now $37 million.

MR. HOBERG: Mr. Jeter, are you still wanting to strike that 15 through 21?

THE WITNESS: Yes. I would like to strike it, because I was referring to his original exhibit which was not inconsistent.

MR. HOBERG: Lines 15 through 21 on page 7 should be stricken and replaced with what you just said?

THE WITNESS: With what I said, yes.

COMMISSIONER REINBOLD: What are the lines?

MR. HOBERG: 15 through 21 of page 7 of his rebuttal.

THE WITNESS: It does not change anything.

I still think the exhibit is meaningless, but I had called attention to something I thought was wrong and I was wrong. It is incorrect in his new version attached to part of Exhibit 20.

MR. HOBERG: Thank you. Please continue.

THE WITNESS: It is incorrect in his new version attached to -- as part of Exhibit 20.

Q. (MR. PEARCE CONTINUING) On page 7, at lines 12 to 13 of his testimony, Mr. Majoros states, An excessive depreciation rate is one that produces depreciation and expense more than necessary to return a company's capital investment in an asset over the life of the asset.

Do you agree with the statement?

A. No, because it's incomplete. The Federal Energy Regulatory Commission in its Uniform System of Accounts for natural gas companies, paren, also used by this Commission for the gas companies subject to its jurisdiction, close paren, defines depreciation as:

> The loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which

are known to be in current operations and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the arts, changes in demand, and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.

The term "service value" is defined as the difference between original cost and net salvage value of gas plant. Since service value includes net salvage in addition to capital investment, Mr. Majoros omitted an important aspect of the recovery of cost that is necessary through depreciation provisions.

I'd like to also comment here about some of the things that were said yesterday. The expense provision for depreciation includes cost of removal or salvage net and that means that they would either be higher or lower depending on the estimates of whether there's net cost of removal or negative salvage or salvage itself. The reserve is there for

the retirement of the asset and for the cost of removal or salvage as often happens. His comparison is misleading because he's leaving out those aspects of reserve for depreciation in his comparison.

Q. How would the omission of net salvage affect his determination of excessive depreciation?

A. Well, his comparisons are not only baseless, but they're also incorrect in that the entire cost is not included in his thinking. If the net salvage is negative and is estimated at 30 percent of the asset cost, he would be asserting that since the depreciation expense exceeds current additions, it is excessive. That is a wrong comparison to start with, but, in addition, he would be leaving out the fact that the expense would have to be 130 percent of the amount necessary to recover the investment in order to provide for the negative salvage or cost of removal in excess of salvage.

Q. On page 7, line 16, through page 9, line 2, Mr. Majoros quotes a U.S. Supreme Court decision in 1934 as a basis for his contention that excessive depreciation results in the extraction of capital contributions from ratepayers.

Would you please comment on that?

A. Yes. Mr. Majoros seems to have missed the

point of the Court's ruling. He refers to a cite of this decision in the NARUC Depreciation Manual as proof that it is still relevant law. The section in which this term is cited is The Brief History of Utility Regulation. Now, as an aside to that, that's a nine-page chapter. It's the first chapter of this book put out by the NARUC. The following chapter is entitled, quote, Current Concepts of Depreciation, end quote. So the chapter that he's referring to is actually a history of what has happened. Obviously, depreciation practices were still in the development stage in 1934.

Now, I'll go back to the text here. The NARUC text point out the fact that this decision overruled a 1930 decision for depreciation on fair value. That means a value that reflects changes because of inflation, typically, over time. In other words, at that time they were depreciating plant using reproduction cost, new. In other words, they were taking account of inflation over time and then depreciating that inflated amount rather than the original cost of the plant.

Now, since some of my comments about things I've read are not necessarily believed by others, I'd like to read into the record the information

that I was just talking about. And this is from page 3 of this NARUC Depreciation Manual. And it's the third full paragraph.

In 1930 the opinion of the Court had changed and reflected the belief that depreciation expense should be based upon present value rather than original cost. United Railways and Electric Company of Baltimore versus West, 280 U.S. 234, 1930. That opinion appears to have been overruled in the 1934 decision, Lindheimer versus Illinois Bell Telephone Company, 292 U.S. 151, 1934, wherein the Court stated, The method is designed to spread evenly over the service life of the property the loss which is realized when a property is ultimately retired from service. According to the principle of this accounting practice, the loss is computed upon the actual cost of property as entered upon the books, less the expected salvage and the amount charged each year is one year's pro rata share of the total amount.

So this issue had to do with whether we depreciate fair value of the property determined using various indices to estimate the value of an existing property that had been in existence for some time and then depreciating that value, or if we

should use original cost. I frankly had not heard of this case until this testimony was done. And the case you hear of is discussed in the rest of my written testimony. So I'll begin there.

Subsequent to the Hope Natural Gas Company case decided by the Supreme Court in 1944, most regulatory commissions stopped using the value method for measuring the rate base investment and switched instead to the original cost method of measuring rate base. To that extent, I believe the 1934 decision cited by Mr. Majoros is consistent with current regulatory practice, which generally uses original cost rate base for ratemaking. I believe the references in the decision to excessive recovery of depreciation refer to the use of value rather than cost in setting rates. That is certainly not an issue in this case since neither the rate base nor the depreciation amount is derived from an estimate of the current value or replacement cost of the plant.

Q. On page 9, lines 3 through 24, Mr. Majoros shows the relationship of the accumulated depreciation reserve to the plant in service and concludes that the reserves are extraordinarily high, to use his term, and that they suggest that

higher depreciation rates have been excessive.

Do you agree with this conclusion?

A. No. Without information about the average age of the plant, prior retirements, et cetera, it is not possible to tell at what level the accumulated depreciation provisions the reserve should be. Once more, Mr. Majoros has expressed his opinion without benefit of any evidence to support it.

Now, I'd like to comment here again that in his discussions yesterday he mentioned the 70 percent ratio of one of the plant items depreciation reserves to the plant cost itself. And I think we need to understand what's in those depreciation reserves in order to understand those ratios. They're not used to separate. This book says over and over that that shouldn't be done. And there are very few situations in which regulatory bodies actually look at the reserve for depreciation and say that reserve is too much or too little and we're going to correct that right away. It's done in the telephone industry to some extent, but other than that, it's practically not done at all.

The reserve has the provisions that have been charged to expense for cost recovery and for

net salvage, whether it's positive or negative, in it. Credits for salvage increase the reserve. Plant cost retired is in the reserve as a negative amount. In other words, we depreciate over the years with the idea that when the plant is retired, that depreciation reserve will equal the amount of the cost of the plant and the two will offset. It also has charges for the cost of removal because when plant is retired and must be removed, then those costs are charged to the depreciation reserve also because they have been provided for in the provision for depreciation and that goes into that reserve.

Deciding whether reserve is too high or too low is difficult. Mr. Majoros compared the reserve for all distribution facilities which is impossible to understand on its face because it includes a lot of different kind of properties, a lot of different existing ages of those properties, and a lot of different lives of those properties. You need analysis, but usually that's not done in modern depreciation practices other than as a sort of test of what's been done in more detail using curve fitting techniques that are typically used in determining depreciation rates.

Q. Are there others aspects of the level of the depreciation reserves that should be considered?

A. Well, yes. The amount in the reserve includes amounts that are set aside for the net negative salvage, as well as the amounts needed to recover original investment in the plant. Obviously, that makes the percentage relationship of the reserve to the plant amounts look larger than it would if only the investment recovery portion of the reserve were compared. More importantly, the larger the reserve balance is, the lower the rate base is and the lower revenue requirements for return and income taxes are. In some cases the level of reserve can also affect the levels of property taxes paid, and reduce them if the reserve is higher.

Q. Could you quantify the effects of the lower rate base?

A. Yes, I can do that roughly, and I want to emphasize the word "roughly." The direct effect of the lower rate base caused by larger depreciation reserve balance is to lower the revenue requirement. If it is assumed that depreciation has been less -- had been less by the amount of Mr. Majoros' proposed annual adjustment of depreciation since rates were set to be effective in late 1994, we would have

eight years, '95 through 2002, of Mr. Majoros' $2.172 million proposed depreciation expense reduction accumulated in the reserve for depreciation by the end of 2002. That would have reduced the reserve by $17,376,000 and increased the rate base by the same amount.

The effect of an increase in rate base of $17,376,000 would be to increase the revenue requirement. I've computed those amounts using Montana-Dakota's proposed 11.044 percent rate of return shown on Dr. Gaske's testimony and the 39.61 percent combined federal and state income tax rate supplied to me by the company.

Q. And what are the effects on revenue requirements using those assumptions that you mentioned?

A. The revenue requirement avoided because of the 17,376,000 is in the depreciation because that's in the reserve is about 3.2 million annually, which exceeds the 2.2 million annual depreciation adjustment proposed by Mr. Majoros. This means that there would be a greater reduction of revenue requirement -- I said would. There will be a greater reduction of the revenue requirement every year from 2002 on by having the 17,376,000 in the

reserve, than Mr. Majoros' proposed reduction in annual depreciation expense. In addition, the revenue requirement reduction does not reduce the amount of investment being recovered by Montana-Dakota as Mr. Majoros' proposed depreciation expense reduction would. The higher depreciation reserve balances, resulting in a lower rate base, has benefited Montana-Dakota's customers and continues to be a benefit in terms of reducing the revenue requirement.

Q. On page 10, lines 2 and 3, Mr. Majoros states, according to the company, no specific studies have been prepared regarding the adequacy of the depreciation reserve or calculation of any theoretical depreciation reserves.

Is that true and, if so, can you explain why it is true?

A. I understand it is true, and it's certainly appropriate. Theoretical depreciation reserves are discussed in the NARUC text on depreciation, this document, to which Mr. Majoros referred in his testimony. On page 24 the author states, quote, If, for example, depreciation rates have been prescribed by regulatory authorities for an appreciable period in the past, it would be inconsistent to deduct in

establishing a rate base a larger or smaller amount than book depreciation reserve accumulated under the prescribed rates, end quote.

The reason that the company has not done studies of the adequacy of the depreciation reserves or determined theoretical depreciation reserves is that it's inappropriate. Adjustments of depreciation are nearly always done on a prospective basis based on the determination of changes in average service lives or determinations of average remaining service lives, more often remaining service lives.

Q. On page 10 of his testimony Mr. Majoros expresses his opinion that the 1991 depreciation study by Stone & Webster included an extremely high cost of removal factor for account 380, services. Do you agree?

A. No. The 1991 depreciation study of Stone & Webster included a review of account 380 additions from 1936 through 1991 and related salvage data to the extent that it was available. I'd like to insert here some discussion, because I did not talk about the level of net cost to remove or net negative salvage that is in this case and I think that it is more understandable if you start to think

about what's involved than it is if you just look at those rates and say they're too high.

For instance, in salvage in the services area, the service again is the line from the main in the street to the home. They're typically a small-diameter pipe. The installation -- and I think there was an example of $1,000 installation yesterday, and I'd like you to think about what happens when that is installed and then a period of time of 35 years goes by and then it's taken out. For whatever the reason, maybe it's replaced, maybe it's taken out because the home is no longer occupied, but for whatever the reason. It seems to me that it probably would cost about the same amount in terms of labor, time, and equipment, and so forth to take that line out as it did to put it in in the first place. However, in 35 years the cost of doing that is going to have increased. I looked at the Consumer Price Index, and in 1967 the Index was 32.9, in January. In January of 2002 the index was at 177.1. So if the cost of doing these activities has gone up by the inflation amount shown by the Consumer Price Index, the cost would be over five times as much.

So when an estimate of net cost of removal

is 140 percent of the original cost of the facility, that may be pretty close to what's involved, but it may also be short. It may actually cost more than that. So I was accused of not having thought about this or reacted to those salvage amounts. I didn't look at the study in any detail at all, but I'm certainly more willing to accept what people did in an extremely detailed study than to just say offhand those are wrong. And so I think that the amounts that are there are reasonable, probably. Now, I can't swear to that because I haven't done the work that's necessary, but I would certainly wait until somebody does the work in the current study to see if those amounts are reasonable.

And I should mention the inflation during that 35-year period that I talked about was greater than normal. It amounted to 4.9 percent a year because of very high years in the '70s and '80s that we had some very high inflation, but even at 3 percent a year in 35 years, prices will go up 2.8 times so it's still something that has to be dealt with when you're dealing with longer life properties.

I'll continue with the rest of that answer. I would rather rely on that study than Mr. Majoros'

reaction, which seems mainly to be based on the effects of the salvage estimate rather than the basis for it.

Q. On the same page 10 Mr. Majoros concludes that the 36-year life for account 376, mains, and the 34-year life for account 380, services, may be excessive based on his experience in investigating other gas depreciation rates.

Will you please comment?

A. Yes. Again, I would rely on Stone & Webster's 1991 depreciation study. Mr. Majoros' opinion may be based on his experience, but his opinion was formed without any specific determination of the proper life or any specific basis for the life he would have led. The Stone & Webster's study used data from 1936 through 1991 and curve fitting techniques that resulted in the use of the R3 Iowa Curve to determine the 34-year life for the account 380, services. The study used data from 1944 to 1991 for account 376, mains, in the same manner to determine an R5 curve fit and a 36-year life.

The approach used by Stone & Webster for these two accounts is widely used by depreciation experts, including the FERC staff, to determine the

appropriate lives to use to depreciate gas utility plant.

Q. On page 11, lines 1 through 15, Mr. Majoros discusses the geometric mean turnover studies he used to test service lives.

Will you please comment on that?

A. Yes. First, the use of the word "studies" should not be interpreted to mean he did a depreciation study. What he did is a very limited review of certain data, with some unexplained calculations. He said in the testimony that he used the last five years of additions and retirements. However, his Exhibit MJM-5 shows additions and retirement for the period 1985 through 2001. In addition, his exhibit labels certain of the data as a three-year band and it appears not to be for any three-year period. His schedules on Exhibit MJM-5, pages 1 of 4 and 3 of 4, show average plant balances in column b for each year based on the balances at the beginning of the current year and the beginning of the prior year, which means the average balances are all shown for the wrong year. They are all actually averages of the year previous to the one shown.

The average plant balance additions and

retirement shown under the three-year band caption are in each instance the sum of the current year and the previous year amounts from columns b, c, and d. Thus, they are not for three years and they use those incorrect average balances from column b that I discussed. Using the data for this 17-year period Mr. Majoros computed a life estimate of 108.07 years for account 376, mains, and a life of 68.53 years for account 380, services. He does not explain how the data for this 17-year period is reliable, nor how the method he used works to determine the lives.

Now, I'd like to insert here a comment based on the discussions yesterday in the hearing. Exhibit 20 has comparisons of company and industry averages and to put the lives that Mr. Majoros determined in that methodology in context, I'd like you to look at the second piece of paper in Exhibit 20, which is the statistics for lives that he presented. And in that example taking mains, which is account 376, the company life is shown as 36 years. The lives that he got averages from statistics for gas plant, and I assume a rather wide group in the United States are around the 50- to 55-year lives. The minimum life was 10 and the maximum life was 80.

As I'll discuss later, Mr. Majoros has adjusted his MJM-5, and he now finds that the life should be 116 years. One hundred sixteen years exceeds the maximum life of 80 years shown on his schedule by quite a lot and I think is totally meaningless in the context of depreciation rates for this company.

Similarly, on the services the company is using a 34-year life. The range for others is from 10.2 to 40 years. And the maximum life shown was 63 years. His revised determination is 74 years. Again, substantially higher than any other company has or is using. That's in the survey that he produces numbers from.

I'm going back to the text now. In the case of account 376, mains, the 1.167 million of retirement for all of the years from 1985 through 2001 are only 6.2 percent of the balance at the beginning of 1985, and a smaller percentage of the 1985 balance plus subsequent additions. In the NARUC depreciation text mentioned by Mr. Majoros, the turnover methods are discussed in Chapter 8. The geometric mean turnover method he used is described on page 81 as follows, quote, The Asymptotic method and its simplified form, the

geometric mean method, are based on ratios of annual additions and retirements. The latter method more readily indicates trends, but is also prone to producing results with considerable variability. The simplicity of the turnover method and the ease with which they may be applied explain their popularity. Their use is restricted by the assumptions of uniformity and their failure to provide an indication of retirement dispersion. These problems led to their replacement by the Simulated Plant Record model.

Further, under the caption "limitations" on page 92 of the same text, NARUC text, the following summary statements about turnover methods are made. Quote, All of the methods assumed uniformity of the growth ratio and dispersion of retirement for each vintage. A more reliable estimate may be made if the property has experienced at least one life cycle, roughly twice the average life, since, under the consistency assumptions above, the property will be at stability. Since utility property typically does not meet the above consistency assumptions, the method may produce considerable variations in life indications. This is especially true for the geometric mean method.

Now, if you think about applying that, this document says that you need roughly twice the average life of data. Twice of average life that he determined would be 232 years, and I don't think we have any data back to the 1700s.

The 1968 addition of the NARUC text stated on page 138 -- now this is a long time ago, this document. Turnover methods are currently used very little because improved methods have been developed for determining service lives from recorded data. I do not believe Mr. Majoros' conclusions based on his very rough analysis of this data should be given any weight in determining the proper lives to use for Montana-Dakota distribution facilities.

Q. Turning for a moment back to page 14, line 21, you said chapter 8. Did you mean chapter 7?

A. Excuse me. Chapter 7. I misspoke. I also would like to insert here that during Mr. Majoros' summary yesterday he mentioned that the Stone & Webster study had talked about a turnover method and he quoted a paragraph from page 4 of their report. I'd like to quote it again and comment on it, if I may.

I believe the quote was -- and this is from page 4 of that document. The turnover testing is a

procedure in which the adjusted turnover period, the number of years it takes an investment in plant to be retired, is determined by aggregating additions from the year 1991 backward until the total is equal to the plant balance in that year and then adjusting for the rate of growth in the account.

Now, keep in mind, they're talking there about dealing with additions back through the years from the time that they did their study until they could account for all of the balance that was there when they looked. I just mentioned he looked at only 6.2 percent of the retirements in his study and that the additions would have been something less than 50 percent. So he did not do what Stone & Webster said they did. They were both called turnover methods, but his method is a much simpler and less reliable method.

Q. On pages 11 -- sorry. On page 11, line 18, through page 12, line 11 of his testimony, Mr. Majoros discusses net salvage ratios and refers to his Exhibit MJM-6. He concludes that the company's net salvage recovery is vastly overstated.

Do you agree?

A. No. I believe the 1991 depreciation study prepared by Stone & Webster is a much more reliable

source of information regarding net salvage than a cursory look at the net salvage for all accounts over a five-year period. By the way, Mr. Majoros talked about that method being used in, I believe, Pennsylvania and Kentucky. Which said another way is that it's not used in the other 48 states, nor by the FERC, nor by the FCC, nor by anybody else that I'm aware of. It is a method that is bound to charge the wrong customers for these items. The new financial accounting standard is clearly aimed at having the cost of removal spread over the life of the facility so that the customers that have the benefit of that facility are paying for it. Spreading net cost of removal or salvage from a previous five-year period doesn't accomplish that at all and it is bound to be incorrect.

There's been several mentions of a gain on the sale of a building. And I may cover that later in the printed documents. I will. But it's been mischaracterized as a gain several times, including this morning again in cross. There was no gain on the sale of the building. Salvage is the entire amount realized from the sale of the property when it's retired, not the gain on the sale. This building was sold for book value. The salvage went

to the depreciation reserve and there it reduces rates for customers because it's a reduction of the rate base.

And in addition to that, it equaled the amount that they needed because they sold it for book value. So this using a five-year average and including $4.6 or 8 million in the future five years based on that, is totally wrong. First of all, even if that should be done that way, and it shouldn't, but if it should be done, there's not going to be another sale of a building likely in every five-year period in the future, nor one-fifth of that amount realized in any of the five years. It's just absolutely wrong.

I want to make sure everybody understands there was not a gain on the sale. There was nothing that the customers are never going to realize. This building was sold for its net cost. In other words, its original cost less the depreciation that had been accumulated on it from the time that it was placed in service.

And I'm going to continue reading now from my text. I also believe that the cost of removal will tend to be paid near the end of the average life of plant facilities and cannot be estimated

accurately using broad averages of short periods of data as was done by Mr. Majoros. Mr. Majoros used data without so much as questioning. The amounts by year for natural gas vary from $79,685 to $440,703. In addition, the amounts for common utility facilities varied from 12,377 in 1997 to $4,889,037 in 2001.

As I mentioned, I understand that the large amount in 2001 involved the sale of an office building for 4.6 million. The electric amounts include an insurance recovery of about 1.8 million and much of the other salvage during the period is for vehicles and work equipment. These are relatively short-life assets. The salvage very often is trade-in value when work equipment is traded in on new work equipment.

I will discuss the recommendation -- excuse me. In summary, Mr. Majoros has very little basis for his comment and for the effect of net negative salvage he used in his final recommendation. I will discuss that recommendation later in the testimony.

I do not understand Mr. Majoros' comments about the recovery being overstated. I assume the accounts being recovered are being recorded by the company in the records. Perhaps he means that the

amounts being recovered are excessive, and I have commented above about his complete lack of evidence for that claim. He also states on page 12 of his testimony that the company's, quote, ratepayers are being penalized, end quote. The ratepayers will receive full benefit of the amounts recorded by the reduction in rate base as I described above.

MR. HOBERG: Perhaps this would be a good time to take a 10-minute recess. I think we're going to continue for a while. Let's take a 10-minute recess at this point.

(Recess was taken.)

(Exhibit 21 was marked for identification.)

MR. HOBERG: We're back from recess and, we'll continue the examination of Mr. Jeter.

Mr. Pearce, please.

MR. BINEK: Your Honor, I just wanted to mention that I passed out copies of Exhibit 21 during the break.

MR. HOBERG: Thank you, Mr. Binek. This is the big one. It's the data request 21 and the response, which is marked as Exhibit 21. Thank you.

COMMISSIONER REINBOLD: 21?

MR. HOBERG: 21, yes, Exhibit 21.

Mr. Pearce.

Q. (MR. PEARCE CONTINUING) Mr. Jeter, included in Mr. Majoros's testimony in a discussion of salvage he says, it appears that the company has not recorded any net salvage at all for services. Is that true?

A. No. I understand from company personnel that the company has recorded 1.4 million of net negative salvage for services during the years 1995 through 2001. Mr. Majoros took his data from a report of retirement work in progress, RWIP, which because of the use of blanket work orders shows services combined with mains. That is apparently the reason he concluded that there was no net salvage applicable to services.

Now, earlier this morning this was discussed again. And at the time that I wrote the testimony, I had just been informed of that. Subsequently, I asked for some data from the company to explain that. And I should mention I think this was an unfortunate thing. The response to the original data request was misleading. I think there was reason to believe looking at it that there were no salvage amounts for services because they didn't show there. And they were combined because of the kind of blanket work order treatment the company

gives them.

But, in any event, there were actual net cost of removal for services during the period involved. And I have with Exhibit 30 summarized several pages of data that I was given by the company. Each of those pages is headed up services-removal cost. And I have taken the total amount for the year from each of those pages and summarized it in the column called annual on the top page. And you can see from that, that this totals up to $1,387,946.12 or 1.4 million. And the documents that I got did not have monthly detail for all of the months of the year, but on that top schedule I summarized some of those just to get a feel for it. The trouble is, those monthly amounts are not necessarily representative in North Dakota because they're for January and I doubt that there's a lot of construction going on in this part of the world in January, no more than necessary probably. But in any case there were, in fact, a million-four of cost of removal.

Now, I said in my testimony net negative salvage. Looking at these schedules, there could have been some positive salvage that's not accounted for here. I doubt it because typically service

lines don't generate any material that can be sold or used again. But that could be that there is some actual salvage values that are not even in this more detailed review.

Q. Mr. Majoros then guesses the company may be recording cost of removal in connection with services replaced as service transfer expense. Is that what the company is doing?

A. No. As I mentioned above, the company has informed me that the net salvage has been recorded in the accumulated depreciation accounts, the reserve.

Q. Then to the extent you relied on his statements about account 380, services, his conclusion is unsupported; is that right?

A. Yes.

Q. On page 12, lines 13 through 21, Mr. Majoros discusses FAS No. 143 and the changes he believes will be required for fiscal years beginning after June 15th of 2002. Would you please summarize the effects of FAS 143?

A. Yes. I prepared Exhibit JAJ-2, a simple example of the accounting changes involved. On the exhibit -- and it probably would help if we look at that together -- I have assumed a $10,000 plant is

completed on January 1, 2001 and there is an estimate of $500 of cost of removal and no salvage at the time of its estimated retirement on December 31, 2010.

COMMISSIONER WEFALD: I need some help with where this exhibit is found.

THE WITNESS: It's attached to my testimony.

MR. HOBERG: His rebuttal testimony, the very last page.

THE WITNESS: The very last page. In that section we --

COMMISSIONER WEFALD: TAA-5, is that the one we are looking at?

MR. PEARCE: JAJ-2. You must be in the wrong --

COMMISSIONER WEFALD: JAJ-2?

THE WITNESS: Yes.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: The owner of the plant applies a credit adjusted risk-free interest rate to discount the cost of the removal obligation to its present value of $254.17. Now, I'm assuming those things, and the assumptions are basically all shown at the top of the exhibit.

COMMISSIONER WEFALD: Where is this $254 figure?

THE WITNESS: It's at the right-hand side of the top little section there, right below the 7 percent, and it was derived using the 7 percent. That's the present value of $500 10 years out using a 7 percent discount rate. In other words, if you invested $250.17 at 7 percent, 10 years later you would have the $500.

Under existing accounting, as shown at the top table on the exhibit, the depreciation expense would reflect the $500 of cost of removal as an additional provision for depreciation of $50 per year and the total depreciation expense credited to the reserve for depreciation would provide for the retirement of the asset and the cost of removal. The plant and reserve accounts would be zero at the end of the life.

Now, you can see there I've labeled it expense. That's the provision for depreciation that goes to expense and is credited to the depreciation reserve which increases the reserve. At the end of the life -- and this assumes perfect estimation -- there would be $1,000 of plant taken out of the plant records and charged against the reserve, and

there would be payments of $500 to remove that facility. And the balance in the depreciation reserve would therefore become zero and the balance in the plant account would also be zero. That's quite a lot simpler than what I'm going to tell you about next.

Because under SFAS 143 the $254.17 present value of the estimated cost of removal would be recorded on January 1, 2001 as a liability and as an addition to plant. Now, you can see that in the first line of that lower table where plant starts out at $10,254.17. Depreciation of the adjusted plant would be $1,025.42 per year instead of the $1,050 recorded under existing accounting rules. Now, you can see that's a lesser amount, and the reason it's smaller is that we're dealing with a present value of that future payment that has to be made and that's the amount that would be depreciated and recovered through depreciation. In the depreciation -- well, let me read on.

The present value of the liability that would be set up offsetting that addition to plant must be increased each year as the time for settlement approaches. The accretion recorded to do that is the discount rate times the beginning of the

year balance each year. On the exhibit that shows up as $17.79 in 2001 and increases each year until 2010 when it is $32.71. Once again, the plant and reserve accounts, as well as the liability accounts all stand at zero at the end of 2010.

Now, let me take you through this again. We depreciate that additional $254 and, therefore, at the end of 10 years, that's the amount that's in plant and that's the amount we've provided for so the reserve zeros out, and the cost of removal would no longer be charged to the reserve because it's already been taken care of on a present-value basis. But in addition to that cost to be recognized, there is the accretion each year, which is also an expense that reduces the net income of the company. And that accretion increases over time and takes care of the total discount or $254.83 during the life of the facility. Then when the $500 of cost of removal is paid, that obligation is taken care of. Because the amount at the end would be $500 because of the interest being added each year to raise it to that level. In other words, the present value five years out is greater than the present value 10 years before the cost has to be paid.

Now, I think it's also important to note

that the total expense recorded under both of these systems is $10,500. And that's shown in the total expense column of the second table to be $10,500. That's the sum of the depreciation expense of $1,025.42 each year and the accretion over in the third to the last column. Therefore, that amount changes each year and it increases over time, not a particularly handy thing from a regulatory standpoint in my estimation. But the total cost is the same.

Now, Mr. Majoros said in his testimony, and I'll talk about this a little bit, but he talked about only paying the present value and not taking care of inflation. The inflation is specifically required under 143 and it is required, if you think about it, because you have to pay the cost of removal in whatever the dollar values are at the time that the facilities are retired. So inflation is part of the process, and it's taken into account here without regard to this discounting. The discounting must also be taken into account to cover all of the cost. In other words, that's part of the $500 of cost of removal that I assumed in this case.

Q. (MR. PEARCE CONTINUING) Just one quick question, Mr. Jeter. I think, if I heard correctly,

you may have misspoken. In the upper part where you said the figure at the bottom of the plant retirement comment, I think you said 1,000 as I heard it. I think you meant 10,000?

A. Yes, definitely. It's the total cost of the plant.

Q. Would you please comment on Mr. Majoros' discussion of FAS 143?

A. Yes. The new accounting standard will cause Montana-Dakota and other companies to change their accounting for retirement obligations. Mr. Majoros indicates that when companies do not have the asset retirement obligations described in FAS 143, quote, these costs will likely be expensed, end quote. If a company does not have such costs, I do not understand what it is that he would have them -- expect them to expense. He mentioned yesterday, if I understood it right, that the principles of SFAS 143 are that you expense the costs as they're incurred and, to the contrary, 143 is aimed directly at expensing the cost of retiring facilities during their life, over their life. And that's done as I attempted to show in the simple example. In talking about this, he talked about only the present value being recognized and that

would not recognize all of the cost.

In addition, his comments on lines 17 to 18 about measuring those costs at their present value, not the future inflated value, suggests a misconception. I don't know why, but he seems not to believe that the full amount of those costs needs to be recovered. The requirements of SFAS No. 143 are to estimate the future cash flow as expected to be spent removing facilities retired and to discount those amounts to present -- current present values. The requirements -- the required computations specifically include an adjustment for inflation. That's covered in paragraph A20 of this document called Statement of Financial Accounting Standards No. 143.

Mr. Majoros is apparently mixing the effects of inflation with the discount rate used to discount the future cash flow to present values.

Q. Do you agree that GAAP does not control ratemaking as he asserts on page 13, line 2?

A. Regulatory agencies are not required to follow the specifics of each accounting standard. Because of this, Statement of Financial Accounting Standards No. 71, accounting for the effect of certain types of regulation, provides for the

accounting necessary to reflect the effects of such regulatory actions. However, I do not think that anyone knows whether the FERC or the various state regulatory agencies will follow this new accounting in setting rates as he suggests will be done. Frequently, these agencies have decided to retain the accounting for ratemaking that they have been using when the FASB publishes a new standard. I believe that is something yet to be decided.

Q. Is FSA-143 relevant then in this proceeding?

A. Well, I believe it is. And the Commission could rule in this proceeding as to the method Montana-Dakota should use in the future for recording asset retirement obligations and the related operating expenses and how such items should be treated for ratemaking purposes. However, it is possible that the Commission will prefer to deal with the question in a ratemaking -- in a rulemaking-type proceeding involving all of its jurisdictional companies. If it is ultimately decided that the provisions of SFAS No. 143 are to be used for ratemaking, it is obvious that those provisions are relevant. If existing practices are retained, the company must still comply with SFAS

No. 143 and difference must be accounted for under the provisions of SFAS No. 71.

Now, I should mention at this point that this simple example that we went over doesn't begin to recognize the complexities of applying this in real life. The assumption, for instance, that this is a plant that is built and the entire amount is retired 10 years later doesn't apply to things like mains and services and telephone poles, and so on. Those things tend to be retired over a very long period before and after their average lives. So the computations involved -- and the document allows shortcutting so that you may be able to make the computations based on an average life even though you know that the lives of individual items in a group property will be very different. It does add a great deal of complexity to accounting for these items and I think it would add a great deal of complexity to the ratemaking function to wade through this kind of accounting each time a company asks for a rate change or each time you asked a company to change its rates.

And so I do think this is something that really is better dealt with in a rulemaking proceeding as the company has already asked to have

done rather than in a rate case. But it's relevant because Mr. Majoros brought it into the case. I responded to it only because he had talked about it.

Q. Would you please comment on Mr. Majoros' recommendations concerning SFAS-143?

A. Yes. The cost of removal charged to customers already includes the legal asset retirement obligations defined in SFAS No. 143. However, I believe the Commission may require the company to provide for similar obligations that may not meet that definition and those costs should also be included in cost to service. I certainly do not agree that, quote, The company's experience suggests that it does not have any such obligations, end quote, as Mr. Majoros states at the top of page 14. The definition of a, quote, legal obligation, unquote, in FSAS 143 is quite broad and includes entity promises to a third party, which may include the public at large, about its intention to perform retirement activities. Paragraphs A2 and A3 of the statement discuss that.

I do not agree with his comment on page 14 at lines 3 and 4 that, quote, the costs should be measured at their net present value, unquote. My Exhibit JAJ-2 shows why that shouldn't be done. If

rates are set based on the SFAS 143 procedures, the company must be allowed to recover depreciation of the present value of future net negative salaries and the accretion of the liabilities for asset retirement obligations. The sum of these two elements of cost is equal to the undiscounted cost of removal and both must be recovered to compensate the company for costs it is required to pay when costs are recorded as required under the provisions of SFAS No. 143. Here again, Mr. Majoros seems to be mixing the discounting and the effects of inflation. I believe both should be taken into account in setting rates.

One thing I'd like to add right here. We haven't talked about the rate base effects, but, obviously, if additions are made to plant to set up the obligation, you would probably need to consider whether or not those additions are included in rate base and whether that obligation is an offset. I think theoretically that would be the proper approach, but there are other ways that could be considered. In any event, I did not talk about the rate base treatment, but it would have an impact because of that growing obligation and the straight line depreciation on the other side. So it's

something to be considered.

I do not know how the five-year rolling average expensing approach Mr. Majoros recommends on lines 4 to 9 of page 14 works. However, as I explained above, if the Commission elects to follow the provisions of SFAS 143 in setting rates, the costs that need to be recovered are the depreciation present value of the asset retirement obligation, plus the accretion applicable to the present value obligation. That accretion must be expensed each year to adjust the net present value of the obligation to the new current level. The depreciation would be the same each year for any specific obligation, but the accretion would increase over time. Consequently, it would be appropriate to use -- or it could be appropriate to use a projected average amount over several years in order to allow the recovery of the total of the two parts required to be recorded under the provisions of SFAS No. 143.

If the Commission elects to continue to follow the practices it currently follows, then the differences between the two methods should be recorded as a regulatory asset or liability. The differences would be between, one, the recovery of

the estimated net salvage on the existing basis and, two, the expensing of depreciation of the capitalized present value of the asset retirement obligation, plus the accretion that must be recorded under the provisions of SFAS No. 143 beginning in 2003. In the long term, the amounts allowed would be the same, but the timing of the expense would be different under SFAS No. 143 for what -- from what it has been under Generally Accepted Accounting Principles.

In other words, like so often has happened in the past for deferred income taxes and other items that have been handled differently for regulation, there would be an adjustment made on the books to recognize the difference caused by ratemaking not being exactly in agreement with the other General Accepted Accounting Principles.

Q. Is there any basis for the depreciation recommendation shown on Mr. Majoros's Exhibit MJM-7?

A. No. Mr. Majoros has ignored the previous depreciation study with regard to negative net salvage and has also reduced the recommended provision for depreciation for 2003 by $848,000 based on a five-year average of salvage value he obtained from the company. A review of the data

shown on his Exhibit MJM-6 makes it clear that this five-year summary is not reliable for the use he made of it. If this is the five-year average he recommended on page 14, lines 4 to 8, I strongly disagree with his recommendation. As discussed earlier, there are large amounts included in the exhibit which are not recurring, such as the four-million-six sale of the office building and should not be included in any case. That transaction is unlikely to be repeated every five years. Because of this and other problems with this approach, it should not be considered.

Now, I have prepared a schedule that might help understand how that $848 amount was worked into his depreciation recommendation, and this is Exhibit 29. Most of this exhibit comes from Mr. Majoros' Exhibit MJM-7, which is near the back of his testimony. The column A just shows the average plant. And if you look at the bottom of page 1 of MJM-7, you can see that it totals to 68 million -- excuse me. I'm in the wrong column. The average balance is 68,870 -- excuse me -- 68,787,446. And I've taken the very detailed schedule and summarized it to show distribution and general separate from common. And the common facilities have to be

summarized from his schedule and that's done in note 2 at the bottom, that the schedule shows 5,381,000.03, and 1,768,000 separately on the schedule. So you must summarize those to get to the total, and then there's a little bit of amortization other in that plant and that's $299.

Similarly, on the second page of his exhibit, the annual depreciation for the year 2001 that he recommended is shown and it's been summarized in much the same manner. The 1,291,000 is the top line on his exhibit and then I've combined numbers to arrive at the general and the common plant and then the $7 of amortization plant is added and that agrees with his 2,079,802.

Then for the year 2003 on his Schedule MJM-7, page 3 of 3, this is what was being discussed yesterday with some confusion about how we got from where we are to where he recommends. I've again summarized from his schedule and here his numbers are much more summarized, but the total depreciation at that stage of his 2003 recommendation is 1,937,000 as shown at the bottom of column C. More importantly, the annual salvage which he determined on his MGM-6, which is the exhibit just ahead of the one we've been looking at, is $848,010. He arrived

at that by adding to the natural gas plant about 50 percent of the common plant to come to a total five years that he attributed to natural gas of 4,240,000. And, again, this includes that four-million-six sale of a building, but at this stage only to the extent of about 50 percent, because he has allocated part of it to electric and part of it to natural gas.

And I've taken his computation and broken it down. In that four-million-two is included the 1,444,000 of natural gas plant and when you divide that by five years, it's $288,898. And I've taken that up to show in total for distribution in general of $289,0000. That reduces the provision for depreciation in his recommendation. And you can see that happening between columns C and E. Then the rest of that 848,000 is common facilities. And he would have us deduct $559,000 of salvage with respect to common properties which have a depreciation provision of $440,000 so that the provision for common properties would end up being a negative $119,000 in a year. But that all adds into the total that he did recommend of $1,089,000, and that is shown as the very last figure on page 3 of 3 of MJM-7.

Now, I just thought it would help to run through those numbers. I apologize for the details, but I think that it does help understand what it is that's being proposed.

Mr. Majoros -- now, some of this will be a bit repetitive. Mr. Majoros also allocated the common property amounts between electric and gas utilities based on the salvage amounts for each of them separately, which is not the basis used by Montana- Dakota for the allocation of common plant costs. I think it overstates somewhat the amounts attributed to natural gas based on information I've received from the company, but I can't quantify that for you. In any case, he did not support his allocation, other than to say that it was allocated based on the amounts of salvage.

The net result of Mr. Majoros' adjustments would be a 2,172,000 reduction in the amount allowed for depreciation to an amount of 1,089,000. His proposed adjustment would be over 71 percent of the amount currently being recorded by the company. The proposed adjustment is not supported by any evidence and should not be approved. On page 14, lines 16 to 17, Mr. Majoros states that these adjusted rates, quote, are still excessive because they're based on

lives that are too short. They are conservative from the ratepayers' perspective, end quote.

I do not believe that what Mr. Majoros means by -- excuse me. I do not understand what Mr. Majoros means by conservative, but, in my opinion, his proposed rates are not conservative from any standpoint. Any further reduction would make them even less conservative. With the net salvage adjustment he made, the overall average rate he is proposing is 1.58 percent. It cannot be considered conservative in any way. It is almost certainly inadequate.

Q. Would you please summarize your testimony?

A. Yes. No adjustments in depreciation rates should be entertained until the current depreciation study is completed and an appropriate review has taken place. Current rates are based on a comprehensive study prepared in 1991 and used again in 1994. Mr. Majoros has not done a depreciation study and has no basis for suggesting the changes in depreciation rates he is proposing. His review of the depreciation rates currently in effect is entirely superficial and contains many errors. Thus, the depreciation rate should not be changed based on Mr. Majoros' proposal.

Q. Mr. Jeter, did you prepare Exhibits 29 and 30?

A. Yes, I did. Well, Exhibit 30 has information I received from the company. I prepared the summary.

Q. Right. The first page?

A. Yes.

MR. PEARCE: I will offer Exhibits 22, 29, and 30 at this time.

MR. HOBERG: Any objection?

MR. BINEK: Well, I do have an objection to Exhibit 30. According to testimony of the witness, the response to the data request that was submitted to the consultant was misleading. And may I ask a question of the witness?

MR. HOBERG: Yes.

BY MR. BINEK: Is it correct that the information was never provided to Mr. Majoros?

THE WITNESS: Well, first, I'd like to say I don't think it was intentionally misleading. I think it just happened to be because of the way those schedules were prepared. I think the company probably thought that he had all the information he needed. However, he didn't, and it was understandable, in my opinion, that he didn't

realize that that was there. However, I mentioned it in my testimony so he has been aware of it since my testimony has been filed.

MR. BINEK: But that information was never provided to him, was it, to your knowledge?

THE WITNESS: Not to my knowledge. Could have been. I don't know.

MR. BINEK: I will object to --

MR. PEARCE: What's the basis for the objection? That doesn't go to admissibility.

MR. BINEK: The information that this exhibit relates to is based on information that was requested by the Commission consultant and was never provided to him in the response to his request.

MR. HOBERG: You're not saying it's not relevant now?

MR. BINEK: I'm just saying that it has been brought into this proceeding at this time without having previously been provided to us, even though the information contained in it was requested.

MR. HOBERG: Mr. Pearce.

MR. PEARCE: Well, it's certainly relevant. That doesn't go to the question of relevancy. As Mr. Jeter pointed out, his rebuttal testimony does

state that there was, in fact, a million-four in net salvage in the services account so that would have given Mr. Majoros, I would think, the opportunity to request a data basis for that statement.

MR. HOBERG: Okay. Well, I think it's something that's certainly relevant and helpful to the Commission to have at this point. Do you need some chance to respond further to that then, Mr. Binek?

MR. BINEK: May I ask the witness another question?

MR. HOBERG: You may.

MR. BINEK: Does this information change Exhibit MJM-6?

THE WITNESS: I don't think it would.

MR. BINEK: Thank you. I will withdraw the objection.

MR. HOBERG: Okay. Thank you. I'll admit Exhibits 22, 29, and 30 then. Does that conclude the questions of Mr. Jeter?

MR. PEARCE: Yes, it does.

MR. HOBERG: Thank you, Mr. Pearce.

Mr. Binek, did you have some questions of Mr. Jeter?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Jeter, on page 3 of your testimony you state that you've testified before the FERC, the ICC and a number of state regulatory commissions on depreciation and a number of other accounting issues. Have you ever sponsored a full depreciation study?

A. No. Not the kind of study that was done in this case. I have in natural gas pipelines cases where the natural resource declines were involved and that was basically a unit of reduction approach, but I have not done a statistical curve-fitting type of studies.

Q. Okay. Thank you.

MR. BINEK: I guess could we go off the record for just a moment?

MR. HOBERG: Let's go off the record, please.

(Discussion off the record.)

MR. HOBERG: Back on the record.

Q. (MR. BINEK CONTINUING) Mr. Jeter, on page 4 you state that AUS Consulting is due to make a complete depreciation study by December 31, 2002. What is the purpose of that study?

A. Well, that information was given to me by the company, obviously. My assumption is that it would be a complete update of the depreciation work done in 1991. And, by the way, I don't know that there's any reason to expect very much change since 1991. There may be, but I don't know of any reason.

Q. Why wasn't a depreciation study done prior to the filing of this rate case?

A. I don't know. You'd have to ask one of the company witnesses.

Q. Okay. If that new depreciation confirms Mr. Majoros's suspicion that MDU's depreciation rates are too high by approximately $2 million, is it MDU's intention to file for a rate reduction?

A. I also don't know that, but I do think that could be answered by one of MDU's subsequent witnesses.

Q. Would you agree that if depreciation rates are significantly changed as a result of the study, those changes, whether up or down, should be reflected in rates?

A. Yes. I think the rate change should coincide with the changes in the depreciation being recorded by the company.

Q. So, basically, by deferring this study

until December 31, 2002, MDU will be asking this Commission to conduct two rate cases in the space of six months; is that correct?

A. If the decision were made to reflect those new depreciation results, assuming they change the amounts -- I guess I should say assuming they change the amounts significantly, then there might be a need to review that study and then adjust rates for the company to reflect whatever change that made in the cost of service, but that would obviously be somewhat limited compared to a full-blown rate proceeding, I would think.

Q. Please turn to page 6 of your testimony and read the sentence beginning on line 1.

A. By ignoring that fundamental purpose of depreciation, Mr. Majoros is effectively proposing that the depreciation rate should vary from time to time depending upon the amount of cash the company is investing in projects deemed by Mr. Majoros to be beneficial to ratepayers.

Q. Where in his testimony does Mr. Majoros make this proposal?

A. I think this is just a corollary to what he's saying. He has talked a great deal about cash flow. But he's not mentioned the fact that the cash

requirement for plant comes when the plant is built or purchased. And that's a cash flow that's already taken place. The cash flows for depreciation are the recovery of those amounts over the life of the plant. And some of that cash may be required to pay off debt that was incurred when the plant was built. That hasn't been mentioned. But that's one of the things that must be done.

To the extent that the facilities have been built with equity funds, retained earnings, or newly acquired equity, those investors also require the recovery of their funds. Now, they may recover the funds from one plant facility, reinvest it in the company through retained earnings and invest it in another facility, but that's the way that works. And to suggest that the cash flow from depreciation is just free and there's nothing else to do with it isn't correct.

And I think the thrust of what he was saying -- although, he said at the beginning it's not the way you set depreciation rates, you don't make these cash flow comparisons, but then he proceeded to make the comparison and suggest that the customers are spending all of the money that's being spent for facilities. That's not the case.

And I don't think he made that case and, therefore, you have to kind of assume that he's suggesting some new change in approach. That's all that whole top of that page is talking about.

Q. Would you please turn to page 6 of Mr. Majoros's testimony and read the question at the top of the page?

A. Is depreciation intended to finance plant addition?

Q. What is the first word of Mr. Majoros' answer?

A. No. Now, I just mentioned that he said that.

Q. On page 8, at lines 17 through 20, you accuse Mr. Majoros of ignoring net salvage as a component of depreciation. Where in his testimony did Mr. Majoros assert that net salvage should be ignored?

A. Well, he took it out. The net salvage that was being recorded as a result of the 1991 study was removed from his computations of depreciation, as I understand it.

Q. What do you think the 848,000 is?

A. Well, four-million-six of it divided by 2, roughly, is the sale of the building, which really

doesn't have a lot to do with the salvage and the net salvage on services and mains. And it seems to me that if one proposes to take a five-year snapshot and divide that by five and use that over the next five years, then you must think that that is going to be repeated in the next five years. Otherwise, you're not doing something that makes any sense at all.

Q. But is that net salvage?

A. I don't think it's going to be repeated in the next five years.

Q. Is the number that Mr. Majoros used net salvage?

A. It is, but it's not salvage in the sense of a depreciation study reflecting the salvage applicable to the facilities involved over the life of the facilities. It gets away from the whole concept of depreciation and the concept under the new Financial Accounting Standard in 143, which is clearly not to recognize this thing based on some average of some short period. It's to recognize them based on the life of the facility and the expected cost at the end of its life to remove those properties or the expected credit in the event that there is, in fact, positive salvage.

Q. In fact, does Mr. Majoros include net salvage in his final depreciation recommendation only as positive rather than negative salvage?

A. Yes. Well, he included net salvage and it was positive. I mean, because of the period he selected and some of the extraneous items included in that period.

Q. On page 9 you take issue with Mr. Majoros' observation that the Supreme Court found that excessive depreciation resulted in extraction of capital contributions from ratepayers. Is it possible to have excessive depreciation of the original cost of an asset or group of assets?

A. I have to know what you mean by "excessive."

Q. How would you define excessive depreciation?

A. Well, if you mean is it possible to have estimates of the life of a facility that turn out to be wrong and turn out to be wrong because they're too short, then some would say that would generate an excessive amount of depreciation expense in the ratemaking situation revenues to cover that expense.

But the excess depreciation in that situation, and this is assumptions that -- we say

the life is going to be 20 years and then we discover after the plant has been in service for 10 years, that it's going to be 15 or 25. If it's going to be 25, then you could say that was excessive. It may not have been. The life used during that first period might be exactly right in terms of the best estimate you could get, but when you get better estimates of what the life is, you should adjust. And the typical method of adjusting depreciation is over the remaining life of the facility.

Q. If a utility depreciates a category of plant on the basis of 140 percent negative net salvage when the negative net salvage is, in fact, only 15 percent, would that constitute excessive depreciation?

A. It might if you accept your assumption. Those are both assumptions. One of them is an estimate made by somebody using judgment and historical facts, and so forth, and the other is just an assumption of 15 percent being the right answer. If that 15 percent were to be the amount determined in a new depreciation study, then I would say that you could say that that had been excessive, but only based on saying we made a wrong estimate in

the past, not based on the fact that we know more now and we're adjusting our estimate. So there's a fine line between whether it's really excessive or it's excessive relative to what you would be thinking it should be in the future.

Q. On page 11 of your testimony you purport to demonstrate that since 1995 the depreciation which Mr. Majoros claims to be excessive would by now have paid for itself in the form of rate base deductions; is that correct?

A. In effect, that's a short way of saying it, I guess.

Q. Did you quantify your rate base deduction by multiplying Mr. Majoros' $2.172 million depreciation expense adjustment by the eight years that have transpired between 1995 and 2002?

A. Yes.

Q. Mr. Majoros' correction is to eliminate the negative salvage and to amortize positive salvage over five years; isn't that correct?

A. That's my understanding, yes.

Q. What makes you believe that Mr. Majoros' adjustment, if applied in 1995, would have amounted to 2.172 million?

A. Well, I emphasized the word "rough" when I

started on this. I did not attempt to go back and figure out what Mr. Majoros' adjustment would have been had he made it in '95. I think that's clear from the way I described it. But I would admit that had he made a similar adjustment back in 1995, it probably would have been somewhat less because there was less plant at that time. I think. Now, I did not do that. This is very rough. It's an example more than anything.

Q. Well, Mr. Majoros would not have included the $848,000 in positive salvage because it didn't occur until 2001; isn't that correct?

A. I don't know what the positive salvage or negative salvage would have been or what five-year period he would have chosen.

Q. MDU's gas distribution plant was a smaller total amount in 1995; would you agree?

A. Yes. And I already said that would have an impact. I did not calculate it.

Q. And so the elimination of negative net salvage would have been a correspondingly smaller amount, wouldn't it?

A. Probably. I don't know. I haven't looked at it.

Q. Wouldn't the result have been a rate base

offset somewhat smaller than the 17.376 million that you ponder on line 4, page 11?

A. It might very well have been, yes.

Q. On page 12 of your testimony you argue that it would be inappropriate to calculate theoretical depreciation reserves to determine whether a reserve excess or deficiency exists. Are you familiar with the term "remaining life depreciation"?

A. Yes.

Q. Would you please describe what that term means?

A. It involves determining the life of the facility, an estimate of the age of all of the facilities, and thereby arriving at a remaining number of years that you would expect those facilities to exist before they're retired. And then converting that to a rate using the total cost of the facility less the depreciation reserve as of the same day.

Q. Does MDU use remaining life depreciation?

A. Yes. It's my understanding that that's been done based on what I've read in the 1999 -- '91 study.

Q. Doesn't remaining life depreciation effectively amortize any reserve excess or

deficiency over the remaining life of each category of plant?

A. Yes. That's why most depreciation studies don't include trying to figure out what a theoretical reserve will be. It's taken care of over the remaining life in any event.

Q. Earlier you discussed R3 Iowa curves. Do you know what a generation arrangement is?

A. Yes. I don't know that I could describe it. I've read quite a little bit about it.

Q. How do you calculate an average remaining life?

A. Well, it's calculated based on the retirement dispersion that is determined using the curves after having determined from the existing data about plant what is the best fit. In other words, the Iowa curves are based on actual evidence of what the lives of various kinds of facilities were. And it was found that using those curves, you could ordinarily find a fit for almost any sort of -- as they referred to them, industrial property, to one of the various curves, the right, left and symmetrical curves.

Once that's done, you have a dispersion of the asset retirements that you would expect and you

can determine using the remaining life of those that have not already been retired what the remaining life would be to use in that situation. Now, that's a pretty rough discussion of that. I have not done that kind of a study. So I understand what's done, but I'm not an expert on using those studies to do what's done other than on a very broad basis.

Q. What is an O curve?

A. I don't know.

Q. Do you know why an O curve is different than an R curve?

A. Did you say L?

Q. An O.

A. No. I think there have been some additional curves developed. I'm not familiar with the O curve.

Q. On pages 13 and 14 and 15 you challenge Mr. Majoros' discussion of service lives for mains and services. Did Mr. Majoros recommend any changes to the service lives underlying MDU's current depreciation rates?

A. No.

Q. From the standpoint of its impact in this case, your criticism of Mr. Majoros' service life discussion is irrelevant; isn't that true?

A. Well, I think it's relevant because I would hate to think that anybody would seriously contemplate a change in depreciation rates based on the 116- and 74-year lives he determined with the only computations he did with respect to service lives. I certainly agree he did not reflect those in his final recommendation. To that extent, it's irrelevant, I would agree, but I don't think I could just not comment on it when I don't think it should be used.

Q. On page 21 you argue that if the Commission elects to apply FAS 143 to MDU's cost of removal, there would have to be two elements of expense; one, the depreciation of the annual present value of future expense and, two, the accretion of the asset's value each year; is that correct?

A. Yes.

Q. You also contend that over the life of the plant both methods recover the same amount; is that correct?

A. Yes.

Q. Do they recover that same amount at the same rate --

A. No.

Q. -- that is, is one method front-loaded more

than the other?

A. The SFAS 143 method would recover plant by increasing amounts over time. It would not be front-loaded. It would be back-loaded.

Q. Okay. And the present method is front-loaded?

A. The present method is -- I think I would call it level. There are methods --

Q. Well, if you have the other method being -- what did you refer to -- back-loaded, then isn't this more front-loaded?

A. In other words, there is more and more expense over time each year. In the present methodology there's the same amount of expense each year, unless there are changes in estimates. You would have depreciation that is level with respect to it. Now, we should be careful about this, because inherent in this discussion is a discussion about a piece of plant that is installed and then later it's retired, all of it. We have many pieces of plant here that have varying lives, with an average life near the center of that long dispersion period of retirement. And if you superimpose SFAS 143 over that kind of a situation, I'm not sure I could even answer the questions, but I think it

would still involve back-loading or growing expense over time with respect to any property or group of properties. I frankly haven't looked at that.

Q. Is Montana-Dakota Utilities subject to FAS-143?

A. It is subject to it when it becomes effective, yes.

Q. Isn't it effective now?

A. No, it's effective -- well, it's effective for some companies now, but for companies with calendar-year financial statements, it's effective for next year.

Q. Does MDU intend to implement FAS 143?

A. I certainly think so. They won't be able to file financial statements if they don't.

Q. So you agree that the company is going to have to comply with FAS 143 and you talked about the complexity of FAS 143. But since the company does have to comply with it, the records will be available for ratemaking purposes; isn't that correct?

A. Sure.

Q. I'd like to have you turn to your JAJ-2. If the company did not have a legal obligation for the $500 removal, then the bottom half of your table

would be incorrect; isn't that correct?

A. Well, the entire exhibit would be incorrect if they don't -- now, excuse me. You specifically put the legal obligation in there and I now understand your question better. That could be true. And as I mentioned in the testimony, the legal obligation is fairly broadly defined. And if we think about what that means in terms of what a company has to do, it's a little hard to imagine very many things that a company would actually remove at the end of the life if they're not required to do so.

Now, there are a lot of people that are making requirements of companies to do that kind of thing. The regulatory agency could probably rule on such things and that makes it become a legal obligation, as I read the new standard. The cities that they deal with who were putting things into the streets and alleys, and so forth, may have something to say about whether those items are removed when they're retired. And it seems to me that with the increased concerns of environmentalists, that's all going in the same direction. We are going to have more and more requirements, rather than less. But if there are things that the company feels it must

remove, even though there is no legal obligation to, it would seem to me they would be very limited. I mean, I don't know why they would remove anything if they are not required to do so.

Now -- and it isn't just removal. In some cases they could be required to be do something to pipe that's in the ground, for instance, to make it safe, fill it with an inert substance, for instance, or do something like that, and that's cost of removal as well, even though technically you're not removing it, you're taking care of a cost that's your obligation at the end of the life, if you are doing that in accordance with some legal requirement as defined.

Q. In your earlier testimony you said that it would cost the same to remove a service as the original cost. Do you think that this company digs up an existing service when it replaces it?

A. I don't know, but I should straighten out what I said there, if you didn't hear me earlier. What I meant was, it would cost the same in time. The effort to remove a service might be the same as it is to put it in in the first place. In fact, it may be greater because nowadays a lot of services are plowed in and I don't think you can plow them

out if you are required to do the removal.

But, in any event, what I really was talking about was not cost the same, but take the same amount of effort, and if it took the same amount of effort, my whole point with that was it might cost a great deal more because of inflation.

Q. But only if they have to dig up?

A. That's correct. And it isn't enough to determine what it would cost. You've got to determine whether or not it has to be done and, if so, when and under what circumstances.

Q. And isn't that one of the important concepts of FAS 143, is that it shouldn't be shown as salvage unless there's an obligation to remove it?

A. Well, as cost of removal.

Q. Okay.

A. I mean, actually, 143 does not discuss salvage. Salvage is to continue to be accounted for.

Q. I used the wrong term. Cost of removal.

A. Cost of removal is what it's aimed at. And it definitely is saying if you have an obligation because of the use of the facilities, then you have to recognize it. And I don't think there are very

many companies that are in business for a profit that are incurring and paying costs of removal that they don't have to pay. I mean, I just don't think that's very --

Q. I would agree with that. Are you familiar with the concept of insertion?

A. Not unless you define it for me.

Q. That's okay. Are you familiar with the concept of abandonment in place?

A. Yes.

Q. Okay. What is that?

A. Well, I earlier talked about abandoning buried pipe, for instance, and in some cases that probably will be allowed and it will just stay where it is. It won't be removed. It may require something being done to it if it is, in fact, abandoned. I know, for instance, in gas transmission facilities, cross-country lines, they're trying to provide for all of the things they're going to be required to do because some of that line is very large and if it decays and rusts out, and so forth, you can have a big cavity there, and so they're faced with some significant amount of costs, but not to remove the line necessarily. They may leave it there, but shore it up so that it's not

going to be a problem over a long period of time in the future.

Q. That's when they replace it, right?

A. Well, replace or abandon. If it's abandoned, that would be more likely. If they replace it, I think in the transmission facilities they typically loop it and put another piece of pipe beside it so they wouldn't necessarily retire it, but if they are retiring it, they might leave it underground or because of right of way and other considerations, they might actually take it out and replace it with other pipe.

Q. I'd like to now talk a little bit about this building sale that you've discussed at length.

A. Yes.

Q. Where was that building?

A. Downtown Bismarck. It was the Schuchart building, as I understand.

Q. When was that building sold?

A. It was the first year of that period, so it must have been in 2001. That's when the sale was recorded. I'm not sure if the accounting -- I would say in as large a transaction as that, that's the year it happened also.

Q. What was the original cost of that

building?

A. I don't know.

Q. When was the building purchased?

A. I don't know.

Q. Why was it sold?

A. I don't know.

Q. What was the sale price?

A. The only information I have on that is the sale price was equal to the net book value at the time of the sale, which means the total cost of the facility that the company has paid for it, less the accumulated depreciation, was equal to the sales price.

Q. And what was that net book value at the date of sale?

A. Well, it was four-million-six or so. Exact amount I'm not sure.

Q. Who was the building sold to?

A. I think it was sold intercompany with respect to MDU Resources. Now, I'm not real familiar with that, but I believe it was sold to an affiliate, in any event. Might actually have been another division of the same company. I'm not that familiar with their corporate structure.

Q. How did the sale price come to match the

net book?

A. By agreement, I assume. I don't really know that.

Q. Do you know if MDU tried to obtain the market value?

A. I have no idea.

Q. Would you please provide the journal entries in the company's books that relates to the sale of this building as a late-filed exhibit?

A. I don't have access to those. I think somebody else that's testifying after I am can.

MR. HOBERG: Is this a request you are making of the company?

MR. PEARCE: I think Mr. Keller would be an appropriate witness for that.

MR. HOBERG: Do you want to reserve that question for Mr. Keller?

MR. BINEK: I can reserve that question, unless the company is willing to provide the information.

MR. PEARCE: It's certainly willing to provide, but I think he can clarify exactly what you want and describe it by official title. So I think it might be easier to put in through Keller.

Q. (MR. BINEK CONTINUING) You state in your

testimony that the other 48 states do not use a current period recognition of net salvage; is that correct?

A. I said that this morning, but that's an assumption on my part based on the testimony to the effect that Pennsylvania and Kentucky are doing such things.

Q. I'd like to have you turn to page 157 of the 1996 NARUC manual that you've been referring to.

A. Yes. I'm sorry. What was the page?

Q. One fifty-seven. Would you please read the two paragraphs, the first beginning with the statement, "historically, most regulatory commissions"?

A. Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that since most physical plant placed in service will have some residual value at the time of its retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning are the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from

the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

Some Commissions have abandoned the above procedure and moved to current period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates with the cost of removal being expensed in the year incurred.

Q. Thank you.

MR. HOBERG: Mr. Binek, do you have a number of additional questions?

MR. BINEK: No, I don't believe so.

MR. HOBERG: About how many do you have left?

Q. (MR. BINEK CONTINUING) How often should depreciation studies be done?

A. Well, it's a little bit varied around in various jurisdictions. Many jurisdictions require that studies be done on a periodic basis and I think five years would be fairly typical of that. Others

don't make any requirements and I think some companies go longer times between. Now, they may have looked at the facilities and decided that there aren't any significant changes in what they are seeing with respect to the lives of facilities, and so forth in their records and, therefore, elect not to do it quite as often. But I would say probably in some cases even three years, but depreciation studies are expensive and so three to five to longer periods are probably fairly typical, but with attention to it much more often than that in terms of just deciding whether or not it is required.

MR. BINEK: I have no further questions.

MR. HOBERG: No further questions. Let's take a luncheon recess here. I'm wondering, though, what we should take? An hour? Commissioners request an hour.

COMMISSIONER WEFALD: 1 o'clock.

MR. HOBERG: Let's be back at 1 o'clock.

(Lunch recess was taken.)

MR. HOBERG: Okay. We're ready, back from the luncheon recess, and I think we were -- we just completed the cross-examination by Mr. Binek.

So, Commissioner Reinbold, do you have any questions of Mr. Jeter at this time?

COMMISSIONER REINBOLD: I do not.

MR. HOBERG: Thank you. Commissioner Wefald, do you have any questions?

COMMISSIONER WEFALD: I have one.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. In your testimony you say that the company -- you understand from company personnel and from the exhibit you prepared has recorded 1.4 million of negative net salvage -- of net negative salvage for services during the years 1995 though 2001?

A. Yes.

Q. How does this number of actual cost of removal of services in five years compare to the plant removal costs of service which were figured at 140 percent depreciation?

A. I'm sorry. I don't know that because I didn't have the retirement date that goes with those costs of removal. I think that would be something to look at, but I just did not do it.

Q. So who would I get that --

COMMISSIONER WEFALD: Can MDU provide that information to the Commission as a late-filed exhibit?

MR. HOBERG: Mr. Pearce, did you understand the question and hear it?

MR. PEARCE: I'm not exactly sure we understand the question. Give us a moment here. We'll certainly do the best we can. We'll have to check with the other MDU personnel who are not here, but we'll certainly try to prepare what we understand that request to be.

MR. HOBERG: So it's possible you'll be able to file a late-filed exhibit on that?

MR. PEARCE: Yes.

MR. HOBERG: Okay. I don't think we've had any other late-filed exhibits to this point so that would be Late-Filed Exhibit 1, if you will, that information.

Q. (COMMISSIONER WEFALD CONTINUING) If this number were less than the planned removal cost of service at 140 percent, do some Commissions take a look at actual removal cost and use those versus what the company has planned through depreciation?

A. Well, I would say that most would look at the actual relationship between the cost of removal and the cost of the facility as they're retired, but you almost have to deal with this by vantage. In other words, if some mains were put in in 1968, say,

and removed in 1998, you would expect that to be something like what they had estimated in the depreciation study.

Q. In this case we're talking about the services, not the mains.

A. Okay. Well, and this would be true of either. Let me say services then. They would keep track of how many dollars of plant were involved adding services each year and you almost have to look at it year by year when the retirements are coming out, because, for instance -- and this isn't quite so true for services -- but if something goes in and then two or three years later is taken out of service for one reason or another, I mean, property is destructed or a road moves, any number of things can cause that, then you wouldn't necessarily expect the cost of removal to be what they estimate for the whole life of that group of assets in that vantage.

Q. Well, for example, I live in an older neighborhood built in 1915, so we started out with a coal furnace in our house, which was converted to natural gas when natural gas was brought to Bismarck. Do you know the year natural gas was brought to Bismarck?

A. Well, I understand it was quite early

because I was talking to somebody about the fact that natural gas came into Nebraska in either the late '40s or early '50s, and I understand it was earlier than that here, so it may have been.

Q. So let's say it was even 1950 and at that point then my service main was probably installed to my home.

A. Yes, I would -- it would have to have been.

Q. I've lived in the house since 1970 and there hasn't been any change in my service main during that time so I've been in there 32 years now. So are they anticipating someone is going to be coming out to my house in a couple years and taking out my service main that's underneath my cement driveway?

A. I don't know how long the kinds of equipment that might have been installed in the 1950s would last, but there's a range of time over which assets are retired and so a 50-year sounds like a long time, but that range may go -- assuming that the average life is 50 years, you could have some of them that last 90 years and some 10, but it would be over that whole range and many of them would be clustered around the 50-year point and it might make sense for that facility to be removed or

replaced, or both, because of safety or some other requirement, depending on the condition.

It's hard to answer it any better than that, but I think there are those kind of considerations and in a situation like that, assuming that you would continue to use the house and want gas service, there might just be a new service put in and the existing one removed at the same time or secured and not actually taken out of the ground. Because I suspect that 50-year-old pipe is not going to be worth much to anybody. First of all, if you're removing, retiring it, more than likely there's a reason for that and it's not very good stuff and so you wouldn't expect to be able to use it.

Q. So your answer to my question is that there is more to look at than the actual removal cost versus the planned depreciation removal costs?

A. Well, I think you can look at those things. I just believe you need to look at them in more detail and get down into it and know exactly what it is that you're looking at because there would be varied reasons for things once you got into the details and I think that it's necessary to look at those details.

But your thought of comparing what's actually happening in cost of removal and the relationship of that to the cost of the facilities that's being retired is exactly on point. I think that's what would be done in a depreciation study in connection with trying to estimate what those amounts would be. That's almost exactly what they would be doing. But it would be done at a more detailed level than on a broad overall basis because you don't learn as much unless you get down into those details.

Q. What if the Commission were to say to MDU that we should wait until they get their new depreciation study before we would proceed with this case?

A. Before you would complete the case?

Q. Mm-hmm.

A. I think that's a policy decision on their part. I couldn't answer that. My suspicion is they wouldn't want to do that, but I don't know.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, did you have any questions?

COMMISSIONER CLARK: I have none. Thank

you.

MR. HOBERG: Thank you. Any further questions of Mr. Jeter?

MR. DILLER: I just have one that I might add on to Commissioner Wefald's.

Since we're getting the cost of removal for service signs, I think you said five years, Commissioner. Did I hear that right?

COMMISSIONER WEFALD: We know they have put on the record 1.4 million is their cost of removal and I asked how that would compare to what they had planned in their depreciation study.

MR. DILLER: I think it would be helpful, too, along with that late-filed exhibit, if we could have the number of service lines retired during the last five years.

MR. HOBERG: You want that as a separate exhibit?

MR. DILLER: However they want to do it.

MR. HOBERG: Late-Filed 2 then. Is that possible?

MR. PEARCE: Sure.

MR. HOBERG: Thank you, Mr. Diller. Any further questions of Mr. Jeter? Mr. Binek?

MR. BINEK: Yes, I have one.

FURTHER CROSS-EXAMINATION

BY MR. BINEK:

Q. You said that you incurred 1.4 million in cost of removal; is that correct?

A. Yes. Now, I think somebody said five years. That data was actually from '95 to 2001, so it's actually seven years.

Q. Okay. But those were the costs incurred by the company. What were the amounts that the company collected for salvage?

A. I think that's the same question as we were just discussing. I don't know because I don't know the amount of the plant that was retired, nor how old it was so I can't answer that question, but I do think that that would be answerable with the additional data in the late-filed exhibit, if I understand what's been asked for.

MR. BINEK: I would ask that that be included in that data.

COMMISSIONER WEFALD: And, actually, if it's supposed to be seven years, I would appreciate that. I'm sorry. I didn't realize. '95 through 2001 is seven years.

THE WITNESS: That doesn't match his exhibit, but that's what the data was that I got.

MR. HOBERG: Mr. Pearce, did you get that?

MR. PEARCE: Yeah, that's fine. I have one redirect question, too.

MR. HOBERG: Okay. Does that conclude yours, Mr. Binek?

MR. BINEK: Yes.

REDIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Jeter, in the course of your cross-examination you were asked to read two paragraphs from a NARUC manual. Would you comment on the content of that paragraph and add any additional information you might wish?

A. Yes. The sense of that was that their gross salvage and cost of removal are to be reflected in depreciation rates and that it's difficult to estimate and that some Commissions have abandoned the procedure and moved to a current period accounting. And I just want to say that I think that's absolutely wrong for the reasons I talked about earlier, because it doesn't reflect those costs over the proper period and get the right customer charged with those costs over the life of the facility that's involved.

And then I'd also like to read in the

paragraph that followed the ones that I did read. It says, Determining a reasonably accurate estimate of the average or future net salvage is not an easy task. Estimates can be the subject of considerable discussion and controversy between regulators and utility personnel. This is one of the reasons advanced in support of the current period accounting for these items. When estimating future net salvage, every effort should be made to ensure that the estimate is as accurate as possible. Normally, the process would start by analyzing past salvage and cost-of-removal data and by using the results of this analysis to project future gross salvage and costs of removal.

And the reason I'm very much opposed to this is the reason that the Financial Accounting Standards Board has issued its new SFAS 141. They are deadset on recognition of these costs over the life of the facility, not at the end of the life. And if you think of that in terms of a nuclear generating station, you can see why. Because if you wait until the end of the life of a nuclear plant and then put that cost of removal into the rates at that point, you're charging the future customers, if you can recover, rather than those that benefited

from the use of the nuclear plant during its life. And that's just plain wrong, as far as I'm concerned, from a regulatory standpoint. And it's easier to understand with a nuclear plant, but it's the same thing with others. It's much more difficult to estimate some of these lives of mass properties where they retire over long periods of time, but it's still doable and it's certainly worth the effort in order to get the costs recognized at the time that those properties are serving customers.

MR. HOBERG: Mr. Jeter, did we get in the record what you were reading from again?

THE WITNESS: I'm sorry. I was reading from page 157 of the NARUC Public Utility Depreciation Practices Manual, dated August 1, 1996.

MR. HOBERG: Thank you.

THE WITNESS: And it was -- the part I read was the fourth paragraph on that page and it continues on page 157 and it continues on the next page.

Q. (MR. PEARCE CONTINUING) Just one thing. I think you misspoke. You said 141 and you meant 143, FAS?

A. Did I say 141? I'm sorry. Yes, SFAS 143.

MR. HOBERG: Mr. Binek, do you have another question?

MR. BINEK: Yes, I have one more.

RECROSS-EXAMINATION

BY MR. BINEK:

Q. If you use recent past salvage as a guide, would the overall net salvage be positive or negative?

A. Well, recent based on Mr. Majoros' exhibit would be positive salvage.

MR. BINEK: Thank you.

MR. HOBERG: Anything further then of Mr. Jeter? Thank you, Mr. Jeter.

MR. PEARCE: I'll call Craig Keller.

MR. HOBERG: Mr. Keller, you testified yesterday; is that correct?

THE WITNESS: Yes, I did.

MR. HOBERG: I just need to remind you then that you're still considered to be under oath.

THE WITNESS: Yes.

MR. HOBERG: Mr. Pearce, please.

CRAIG A. KELLER,

having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Keller, you previously identified yourself and gave your position with the company, I think, yesterday. And you have filed some rebuttal testimony in this case. I would ask if you could simply summarize the main points of your written rebuttal testimony and then add anything that you feel is a part of rebuttal to the staff's case.

A. Sure. I would like to start by addressing the capital structure and costs of debt that was used by Mr. King. And I'd like to start by just making sure that when we use the name MDU Resources Group or Montana-Dakota, that we understand that they're the same legal entity and that the balance sheet is the same. MDU Resources Group in essence is really a separate cost center within that legal entity where we track the costs for our resources group and we allocate those to our different businesses. So, you know, when we talk about Montana-Dakota, we talk about MDU Resources Group's balance sheet, we're talking about the same thing.

And I think it's in this statement, Statement A, where Mr. King tries to, I should say, connect the dots between Centennial's debt and

MDU's. He looks at Statement A and on page 1 where we have the unconsolidated balance sheet of MDU Resources Group and he's using that to connect to the consolidated footnotes in that same schedule. And the difference between a consolidated balance sheet and an unconsolidated balance sheet is that MDU's unconsolidated balance sheet does not reflect the assets and liabilities of the subsidiary companies. It only reflects the investment MDU has made in those companies. On the consolidated balance sheet it would reflect all the assets and liabilities of those companies and in essence you'd have a grossed up balance sheet of all the assets and liabilities of the corporation.

In Statement A, page 1 of the balance sheet, that only reflects the unconsolidated balance sheet of MDU. However, when we go to pages, I think, 3 through 29, which are the footnotes, those reflect the consolidated footnotes of the company, the ones that were attached to the company's annual report. On page, I think, 11 of that, footnote 6, it lists the long-term debt, including Centennial's, on which it would be listed because it's a consolidated balance sheet. And Mr. King implied that that debt was part of the unconsolidated

balance sheet of MDU and that's not correct. That would be Centennial's debt and is not really part of Montana-Dakota's individual balance sheet.

Yesterday King made a statement that MDU was attempting to build, quote, a firewall around MDU to separate the debt of Centennial from MDU. And that is exactly what MDU is trying to do. And I'd like to explain to you the reasons for this and why I believe the Commission should support MDU in its efforts. In questioning Witness King, Commissioner Wefald raised a concern as to the negative effect a bad business decision at Centennial, one of its companies, would have on MDU and its cost of debt. And, quite frankly, MDU, as well as the rating agencies, are also concerned about this. The concern is that bad decisions made at Centennial Energy or one of its subsidiary companies could cause default or cause a bankruptcy that could roll up into Montana-Dakota or MDU. And what we're trying to do is prevent this from happening.

One of the things that -- we heard Mr. King use the term "firewall." The same kind of philosophy or term is used by the rating agency. They call it ring fencing and attorneys call it

bankruptcy proof, but what we're trying to do is protect the assets and the customers of MDU from our nonregulated businesses. And the concern we have is that in the event that there were a default at Centennial or one of its companies, we do not want that to cause a default of MDU. Likewise, if there was a bankruptcy at MDU -- at Centennial, we do not want a bankruptcy judge to have the ability to collapse the corporation and provide the creditors of Centennial or the subsidiaries of Centennial, we do not want them to have access to the assets of the utility. We want to protect our customers from this happening.

And there's some things we can do. And one of them is we need to keep separate and distinct books from Centennial, which we currently do. We need to conduct the business of the utility in a manner that is clearly distinguishable and separate from the operations of Centennial, and we do that. MDU does not participate in a money pool or comparable intercompany fund arrangement with Centennial. This means that MDU does not commingle its corporate funds with those of Centennial. It means that MDU and Centennial maintain their own distinct and separate credit facilities. Neither

have access to the other's credit agreements. To further strengthen this point, MDU does not lend funds or otherwise extend credit to Centennial, and Centennial does not do the same back to MDU.

Mr. King stated yesterday in his testimony that all debt is raised and issued by MDU and is simply pushed down to Centennial and the subsidiaries of Centennial, and this is not correct. A first mortgage lien of MDU's electric property and gas is what's used to secure the long-term financing for MDU. The only property that can be pledged under this is qualifying utility property, and this is our electric and gas property. Centennial cannot pledge its nonregulated assets under this agreement and it cannot access this agreement. There are no cross-default provisions in this credit facility where a default at Centennial would trigger a default at MDU. And there are no requirements from MDU from the capital to advance funds for Centennial or a subsidiary of Centennial under this agreement.

Centennial's credit agreements are separate from MDU and require Centennial to use the funds that they raise under this agreement to conduct the operations of Centennial and the Centennial subsidiaries in order to preserve Centennial's

financial integrity. And, simply stated, if we allowed MDU to have access to the funds raised under Centennial's financing agreement, we in essence would give a bankruptcy judge an opening to take and collapse the company in the event of bankruptcy by Centennial to give those creditors of Centennial access to our assets. And they would do this under the assumption that we may be using these funds to benefit MDU at the expense of the Centennial creditors. So we do not want to do this.

And to further strengthen this position, we make it not only clear to anyone that has borrowed money to Centennial that MDU does not guarantee the debt, but nowhere in those instruments do we allow the name MDU to be used in Centennial's credit agreements.

I'd like to comment on Mr. King's Exhibit 16 yesterday. What that was, it was an exhibit showing the working capital of Montana-Dakota. And on there he had materials, fuel costs, prepayments, customer advances. And he made the comment there were material differences in these accounts. In my rebuttal testimony I stated that these accounts remain relatively constant and support the long-lived assets such as property and plant. And I

further stated it is the Company's policy to finance our long-lived assets with long-term debt. This helps mitigate exposure from interest rate volatility over the asset's life.

Now, looking closer at this exhibit, you'll see that from June to July there's a big decrease in the customer advances. And this decrease accounts for essentially most of the variance in the schedule. And this was a result of a refund of a customer advance that was out of the ordinary. It was an abnormal customer advance and it does not reflect normal activity. Without this adjustment in here, the fluctuations would be minimal and it would really be insignificant to the rate base.

You know, I find it interesting that Mr. King himself is inconsistent in his method of determining capital structure with that of setting debt cost. In arriving at debt cost, Mr. King uses the argument that all debt is commingled. Mr. King uses the argument because it provides him with the lowest cost on debt. If Mr. King makes his argument and assumes that debt is commingled, then it would only be logical and consistent to assume that equity, as well as all capital, is commingled. To follow through with his arguments and logic,

Mr. King should then have used the capital structure of the consolidated MDU resource company versus just the capital structure of MDU.

Now, if you look at the consolidated capital structure, the equity portion is over 60 percent, compared to the capital structure just of MDU, which is roughly 50 percent equity. However, if you were to use a consolidated capital structure, you would have to increase the costs of capital. So he chose to ignore. What he does, he picks the capital structure when it fits him and he takes the weighted average wherever it provides the lowest cost of debt, and it, in my mind, is arbitrary and inconsistent.

In testimony yesterday Mr. King stated that the Commission should use December 23rd, 2001 as a base for the capital structure. As I point out in my rebuttal testimony, North Dakota Administrative Code 49-05-04.1 allows for projected test periods. MDU extends a considerable effort to develop budgets and forecasts from which to make decisions and guide our organization. Mr. King did not provide any testimony or evidence to suggest or dispute the accuracy of these projections and, in fact, Mr. Majoros accepts the projected revenue from this

2000 test period in his testimony.

MR. HOBERG: I'm sorry, Mr. Keller, what was the code section you referenced?

THE WITNESS: 49-05-04.1.

MR. HOBERG: That would be the North Dakota Century Code then.

THE WITNESS: Okay. I stand corrected.

MR. HOBERG: Thank you.

THE WITNESS: In setting capital structure and determining debt cost, Mr. King's methods and arguments are illogical, unfair, and even ignore North Dakota's Century Code. Mr. King's attempt to commingle debt with that of Centennial and that of MDU is not only bad public policy, but it also increases the financial risk for our customers. The capital structure that MDU has filed is correct and should be used.

I'd also like to just briefly document addressing comments made on 143. I think Mr. Jeter has done a very good job of addressing the company's position, but the industry itself -- when I refer to industry, I'm really talking about EI and AG, which are associations for electric and gas industries. They are recommending that we take a go-slow approach to FAS 143, and we agree with this. The

methods we use now are straightforward. They're easy to understand and they're easy to implement.

MDU will need to adopt and comply with FAS 143. We're still studying the effects of that and we don't know the ultimate outcome, but we believe that any changes that are required because of that will have little or no effect on MDU or its customers. And the reason we say that is because if there's any difference between what's required in 143 versus what we do for regulatory purposes, we will defer on said regulatory assets as allowed under FAS-71.

I also thought it would be appropriate for me to talk a little bit about the negative salvage or positive salvage and the removal of costs. I worked in the tax department for a number of years, and through the years I spent a lot of time combing through the depreciation reserves for MDU. And I've looked back over probably, oh, early '70s to late '80s. And over all that time, when I looked through those, when you see large amounts of positive salvage, it almost always resulted from one of three things. Either there was a sale of an asset or some insurance proceeds that we received or we traded an asset for another asset.

If we looked at the period we're talking about, there was a sale of an asset and that was the Schuchart building we talked about. And that was sold at net book value. Mr. Majoros refers to that and he focuses on that part of the reserve where the salvage shows up. However, there's also offsetting adjustments in the reserve for the retirement of the asset as well. So the effect was that there was no gain or loss on that asset. And while there shows large amounts of salvage, there really -- all the company did was collect its cost for that building from the affiliate to which it was sold.

Insurance proceeds in this time period, we received insurance proceeds due to the hailstorm we had in 2001, and we received money for a lot of vehicles and other stuff that was damaged. At the end of it, when we did some repairs and stuff, we had money left over. We took that money and we credited the reserve salvage for that so our customers would benefit in the future from that, rather than take any of that money to the bottom line for the shareholders. That money will help lower depreciation rates going forward.

On trade-ins, we have a program where we trade in our equipment, some of our equipment every

other year. It's a very effective program and we can trade equipment in and get brand-new equipment for almost little or no cost. The effect of this is that when you look at a reserve, you'll see large amounts of salvage going in. In effect, all it is, we're trading in. We're showing the salvage on one hand. We're replacing a piece of equipment so we have a property addition on the other hand. There's really no net increase in plant because of those transactions. It just shows up as salvage.

Removal costs, when we talk about mains or services, in talking to some of our people our normal policy -- or I should say a normal retirement of a service in our company would be that we would take, we would cut the service -- the riser off, which would be next to the customer's premises. We would cut that off below the surface and cap it with a weld or if it's plastic, we put a seal on there. But we also will cut it at the main, and we'll cap it there as well. But we just don't cap and leave the whole service line in the ground. The policy or the procedure we usually do is, we take and remove at least a portion of that service line to move it beyond the public easements, and we do that for some reasons. One of them is that we don't want gas flow

in this thing. We don't want the exposure of gas flowing through there. We also don't want dead lines sitting next to the -- you know, to the mains. We don't want the risk that someone may inadvertently mistake a dead service line for the main and think that they've located the proper line, and we don't want to have a situation with our line locators going out there and accidentally marking the wrong line.

The cost can be quite expensive to do this here, because what you're usually doing here, what my people are telling me, is a lot of times when you are doing removing, you're excavating and repairing under concrete and asphalt so the cost can run pretty high. And I think those contribute to the $1.2, $1.4 million that we're seeing in there. The other comment they're saying is that there are now rules that require the company to maintain detailed records of our dead lines. And so our concern or our thoughts are going forward is that rather than seeing a decrease in these costs, we may see these costs increase in the future because we expect there could be more rules coming down regarding dead lines.

So I guess the bottom line is, we've got

all these things going through reserves. Unless you do a thorough depreciation study, ask the right questions, I think it's very difficult to know what the proper depreciation rates are going to be. And it would be my comment the last time we did a thorough depreciation study was 1991. It was done by Stone & Webster. And we haven't done one since. We're looking at doing one.

One of the reasons we haven't had one completed is that right now it's tough to get consultants. Everyone is busy with 143 and everything else. We also ran into a problem in that Stone & Webster, who previously did our study, they had some financial problems, some people turnover and they moved. They have lost all our records that we had. So it's not just a matter of updating our records going forward. We're going to have to go back and provide and reprovide all our records from back as early as we can -- you know, I think we have most of our records, but we're going to have to redo it. So it's going to take a little longer than our prior study. But we're hopeful to have it done by the end of the year.

It would be my recommendation since the last thorough study done was 1991, that that should

be used for setting rates in this case, and that 143, as recommended by Mr. Fox's opening remarks, is that we should move this to another day. It shouldn't be handled in this case.

MR. HOBERG: Thank you, Mr. Keller.

Any additional questions of Mr. Keller?

MR. PEARCE: I have no questions. I just will offer the exhibit.

Q. (MR. PEARCE CONTINUING) Craig, did you prepare your prefiled rebuttal testimony?

A. Yes, I did.

MR. PEARCE: And that's marked as Exhibit 23. I'll offer that at this time.

MR. HOBERG: Exhibit 23-53 --

MR. BINEK: No objection.

MR. HOBERG: -- is admitted. Okay.

Mr. Pearce, did you have some questions of Mr. Keller?

MR. PEARCE: I don't.

MR. HOBERG: I'm sorry. I looked at Mr. Binek and said Mr. Pearce. Mr. Binek.

MR. BINEK: I was about to start asking questions.

COMMISSIONER REINBOLD: These guys are not interchangeable.

MR. HOBERG: Mr. Binek, please.

MR. BINEK: Thank you. I'll take his money, though.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Keller, if there's a bankruptcy of MDU Resources that is a result of activities of either unregulated or regulated entities of Montana-Dakota or MDU Resources, isn't a bankruptcy court going to look at all assets of MDU Resources to satisfy creditors' claims?

A. There's -- it depends on what level. You're saying it's at the parent company level?

Q. Right.

A. At the parent company level, they can look at the assets of that, yes. However, I should point out what we're protecting, is we're protecting our regulated customers from the nonregulated business and that's what you're -- you know.

Q. I realize that, but the protection only goes so far.

A. Well, we're trying to do everything we can do to strengthen that as best we can.

Q. Now, I'd like to have you turn to page 3 of your rebuttal testimony. And specifically at line

16. Are you there?

A. Yep.

Q. Okay. At line 16 you object to Mr. King's use of a historical year-end 2001 capital structure and argue instead for your forecasted 2003 capital structure. What capital structure did the company use in its rate-of-return testimony in the electric case earlier this year? That's PU-399-01-186.

A. I'm going to defer that to Rita.

Q. Okay. Now, please turn to page 5 of your rebuttal testimony. At line 14 -- beginning at line 14 you state that FAS 143 does not provide levelized depreciation rates, but instead pushes higher costs toward the retirement date of an asset due to the discounting method used.

Is it your contention that the current method of recovering negative salary produces a levelized effect on ratepayers over the life of an asset?

A. My comment when I made that comment, and I think Mr. Jeter addressed that quite well, is that because of the discounting that is associated with 143, it tends to push numbers, push a cost toward the back end because of the way the discounting interest accretion is done and that's what I'm

addressing here. If you're going to ask specifics on 143, I guess I would defer to Mr. Jeter because I think he's the expert in that area.

Q. Okay. Let's move forward a little bit and see where we end up here.

A. Okay.

Q. If we assume that an asset has a removal cost of, say, 50 percent of its original cost, that cost is recovered ratably; that is, evenly over the life of the asset, correct?

A. That's the theory behind it, yes, the goal.

Q. And that's what you mean by levelized?

A. When I mean levelized -- when I use my primary term levelized, is that we have rates that are consistent and that the rates aren't changing from year to year. That's what I refer to as levelized. And my concern was under FAS 143 because of accretion, if you follow that to the rule, you're not going to get -- you know, you'll see it pinned on the asset as the asset ages. Because of interest expense, accretion is going to change every year. You will not get levelized rates. They will constantly fluctuate. And when I refer to levelized, that's what I'm referring to.

Q. Haven't you forgotten the rate base effect?

When an asset is new, it has very little negative salvage, the removal costs accrue and ratepayers pay a return in income tax on the whole investment; isn't that correct?

A. Can you restate that for me, please?

Q. When the asset is new, it has very little negative salvage cost that's accrued; is that correct?

A. If you're accruing it ratably, I would assume so, yes.

Q. And the ratepayers pay a return in income tax on the whole investment; isn't that correct?

A. On the whole investment net of depreciation reserve?

Q. Yes.

A. Yes.

Q. Only later when the accumulated reserve is built up to a reasonably high level do ratepayers get the benefit of the rate-based deduction represented by accruals of removal cost; isn't that also correct?

A. I would disagree with that. They get the benefit the whole time because -- they get a return basically based on the unrecovered book value, so, you know, that rate base deduction, as you collect

more depreciation will grow, but they're getting the benefit over the whole time.

Q. But it grows; isn't that correct?

A. On that particular asset, yes.

Q. Isn't it true then that the existing system is front-loaded in contrast to the back-loaded recognition of costs under the FAS 143 procedure?

A. I would disagree with that as well. I think the idea of 143 is to accrue it ratably over the life so that you have a proper matching of use with cost. So, you know, I think when we say -- I think 143 tries to separate the interest component from the other pieces. What they're trying to do, I think, is to add some more complexity there, but I think the intent is to accrue it ratably.

Q. Because of system growth and because of inflation isn't the company always adding more plant expressed in dollars than it is removing old plant? Maybe -- they're adding more new plant than they're removing old plant?

A. Are we talking dollars? Are we talking feet? What are we talking?

Q. Dollars.

A. I believe that we've been holding -- you know, they've been fairly constant over the last few

years, that our overall utilities additions and reserve has been fairly constant, but, you know, I think in some years it's less, some years it's more.

Q. Has there ever been a year when the company's gross plant declined?

A. Gross plant declined? The gross plant?

Q. Right.

A. I couldn't answer that question.

Q. Now, please turn to page 6 of your rebuttal testimony, line 2.

A. Excuse me?

Q. Page 6, line 2. There you say that you consider this plant to have an indefinite life. What do you mean by indefinite life?

A. When you say plant, we're talking about the system. We have an obligation to serve the customer. And so as long as we have that obligation to serve the customer, you know, we think that we're going to have to maintain the replacements whenever necessary to keep the system operating.

Q. Okay. Can you identify the specific plant accounts that you consider to have an indefinite life?

A. Well, I mean, I think what -- the responsibility is to -- we have the obligation to

provide service, reliable service indefinitely, so I would guess that the accounts and the assets we have are necessary to do that, so my question would be which of them -- you know, unless technology makes something obsolete, I'm guessing we need all those accounts. We're going to have to replace all of those assets to continue that service.

Q. Did you hear me asking questions about the building that was sold?

A. Yes, I did.

Q. And I think that I was referred to you.

A. Okay.

Q. First of all, what building is this that was sold?

A. It was the Schuchart building.

Q. Okay. Now, where is that building located?

A. It's located on Divide, the old Gold Seal building.

Q. That's the gold building up here?

A. Yeah.

Q. When was that building sold? I'm going to go through the same questions.

A. I think -- I believe it was transferred, sold to an affiliate, I believe it was July 1, 2001.

Q. What was the original cost of that

building?

A. I don't have the information. It was several million dollars. I don't know the exact number.

Q. Okay. But you can provide that information?

A. We can provide it, yes.

Q. Okay.

A. Now, are we talking about the original cost? There was an original cost plus improvements that were made to the building.

Q. Right. And I think we're going to want all of that.

MR. HOBERG: You want a late-filed exhibit, Mr. Binek?

MR. BINEK: Yes, please.

MR. HOBERG: That would be 3, Mr. Pearce.

MR. PEARCE: That's fine.

Q. (MR. BINEK CONTINUING) And when was the building purchased, do you know that?

A. It was purchased in the early -- early to mid 1990s. I'm not certain of the date.

Q. Okay. Once again, I would ask that all of this information be included in a late-filed exhibit, but I'll go through it anyway --

A. Sure.

Q. -- if you can provide some information. Why was the building sold --

A. Initially, when the building --

Q. -- or transferred? I think you used the term transferred.

A. Transferred, sold. Initially, when it was purchased, we were running out of space in our current building so we acquired this building. As the company grew, the share of activities associated with the resources group became less and it was decided that it should be moved outside of the utility since it's -- you know, I think the utility now is quite a bit less than half of the operations over there, so it was decided to move to a different company.

Q. Okay. And the sales price, do you know what the sales price was?

A. The sales price was set at the net book, unrecovered book value of the asset, and I don't know the number. It seems to me it was in that four- to five-million-dollar range. I don't know. It's here someplace.

Q. And what was the entity that it was sold to?

A. It was a subsidiary of Centennial. I believe the subsidiary's name is Future Source. I can't give you the exact legal name. Future Source.

Q. Once again, that will be included, I assume. And I asked Mr. Jeter, I believe it was, to provide all of the journal entries relating to the sale.

A. Okay.

Q. Was there an appraisal done prior to the sale or transfer of this building?

A. I don't believe so, but I can't answer that for sure, but I do not believe there was an appraisal done.

Q. Do you know what the tax appraisal of the building was at the time of the sale?

A. No.

Q. Can you provide that information also?

A. Yes, we can.

MR. BINEK: Okay. And I'm asking that all of that information be included in a late-filed exhibit.

MR. HOBERG: Late-Filed Exhibit 3.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Reinbold, did you have any questions?

COMMISSIONER REINBOLD: I think so. Probably a statement, too. Everybody is making statements.

EXAMINATION

BY COMMISSIONER REINBOLD:

Q. You know, when I was a kid out at Hebron, 50 miles west of here, MDU was a pickup and two guys with patches on their arms and natural gas and electric service and that was MDU. And everybody accused them of long coffee breaks. And that was kind of a joke in the community, you know. But that wasn't -- I don't think it was the case. They're very efficient. And the point I want to make now is that from that point to now we've really come a long way. And when I say that, I understand MDU Resources Group, Inc., has purchased a number of businesses.

Can you kind of rattle off a list of the businesses that the big MDU Resources now has?

A. Well, I think probably best would be to talk about the lines of business we have. We have, of course, our electric/gas utility operations. We have WBI, which has a transmission and gas storage gathering, as well as an oil and gas exploration, and they also do some -- they have some companies in

what I call innovative technology, where they're looking at, I would say, breaking technology that's applicable probably to some of the things we're in. We also have Knife River Corporation, which invests in aggregate mining, as well as building, road construction and stuff, activities.

We have USI, which is Utility Services, Inc., which is involved in the building and developing of a -- I should say replacing, I would say, utility, electric, gas, overhead, underground lines. They work with the generation side. They do work in telecommunications, as well as inside electrical work, as well as traffic light signaling. And then we have Centennial Power, which is involved in the investment in IPP, looking at doing investments in IPP. And we also have our foreign operations that are currently in Brazil that have made investments in, I think it's 200 megawatts of a gas turbine and they're also looking at some other projects in South America.

Q. You've come a long way?

A. Yeah.

COMMISSIONER REINBOLD: That's all the questions I have.

MR. HOBERG: Thank you, Commissioner

Reinbold. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. In Mr. Jeter's testimony he had said that Montana-Dakota has retained AUS Consulting to complete another depreciation study by December 31, 2002. Are you anticipating that the study will be done by December 31, 2002?

A. Well, we're very hopeful it will be done. As I said, you know, one of the issues and problems we ran into is that we have to provide all our historical records because of the fact that, you know, they inadvertently were lost, but we're hopeful we'll have that completed in that time frame, yes.

Q. That was one thing I was wondering about. With the 1991 study, if the Commission wanted to go in and take a look at that and you're recommending the Commission use the 1991 study, is there any backup data that's available to the Commission at this time other than the few summary charts?

A. I couldn't answer that without talking to our plant people or Stone & Webster and find out what exactly -- you know, what records they do have left from that, you know, that they were able to

locate versus what they don't, but I'm not sure how much information would be available.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, any questions of Mr. Keller?

COMMISSIONER CLARK: I do have a few.

EXAMINATION

BY COMMISSIONER CLARK:

Q. Getting back to this building, if through the tax appraisal that MDU is going to be submitting, and I understand there wasn't, doesn't sound like, a fair market appraisal done, but if the tax appraisal comes back in the market that the assessors here were setting the value of that, if that ends up being far in excess of the net book value, would it be fair to ratepayers to somehow give them some sort of realization of the difference between the two that, in fact, this asset that had been in the rate base that the ratepayers have been paying for was then transferred to another affiliate within the MDU group, but at far less than the market value of that?

Would it be fair to somehow credit, maybe through an offset of that credit that was originally

given, so that the ratepayers see some realization of that?

A. You know, I would comment that that may be fair for the portion that was allocated to the utility business. A couple comments I'd like to make. One, is that while we didn't do a fair market value, we believe that the book value was very close to the fair market value. So we don't believe, you know -- if we thought there was a big discrepancy in the values, we would have went through and did a fair market value of that, but we don't think there was a big difference between fair market value and net. I'm not sure what the tax value is. I'm not sure if that is a locally assessed or centrally assessed asset. If it's locally assessed, we would have the tax value. If it's centrally assessed, I don't believe it would have a value just for that stand-alone business.

Q. What would be the basis of saying that you think it's pretty close to what the fair market value was, the net book?

A. Well, because we haven't had it that long and we made some pretty substantial investments in there, so we're pretty comfortable that the fair market value -- the fair market value would not have

been much higher than the book value was.

Q. Getting back to the depreciation study that is ongoing, kind of lead me through the -- why was the decision made to have a depreciation study at this time? Was it for the rate case?

A. I'm going -- I'm going to defer that to Rita, but I believe one of the things is, one, it's been a while since we had one, but, secondly, with the cases coming up, we wanted to take a look at it. You know, we look at our plant all the time. We don't think -- you know, one of the comments made, we don't think the makeup of our plant has changed a lot since our last study, but, you know, we thought it may be appropriate to do one. I think it was recommended that we do one for these cases, but Rita could probably answer that better than I can.

Q. When it was originally contracted to be done, was it contracted to be done by the time that this rate case was to be taken up by this Commission?

A. We -- right now, I don't think there's as many consultants in the business doing depreciation studies. You know, the number of consultants -- there seems to be a lot fewer than there have been in the past. We had a very difficult time getting a

depreciation consultant. It was tough to get them. You know, they're quite busy right now. It was difficult to get one. The individual we hired did a depreciation study, just completed one for Great Plains, and we asked him to start on this one as soon as he could and he said he would do his best effort to get it done by the end of this year.

Q. I guess I'm a little confused by that, because I know in the RFP that we put out here at the Commission, I think one of the things that was originally in that was a depreciation study and at some point we decided to peel that off and that I guess MDU would be handling it, but -- and maybe Mike will be able to speak to this when we get to Mr. Diller's questions, but it seemed to me that we had at least five that said that they could get it done by the time that we needed to get it done.

You're saying MDU didn't find anybody out there who could get it done in time?

A. We looked for consultants that had been used by our peers that we knew were very reputable and very good and, you know, we kind of basically looked at -- you know, the people we looked at were the ones we wanted to use. They're very busy right now and timingwise it takes a period of time to do

this and it takes a period of time to gather all these records that we have to go back and recreate, so, you know, we just had difficulty getting a commitment to get it done in a time frame that -- in time to have -- you know, time to have -- prior to the case being filed or this date.

Q. Well, the depreciation case that you have, the study that you have being done, is it going to be ready for the rate cases in the other states within your jurisdiction; South Dakota, Montana, Wyoming, the ones we've heard about that will be --

A. Again, I'm going to have Rita -- he's going to do the study for Montana-Dakota gas operations and would include all our jurisdictions. Timingwise, if that's going to fit with our schedule, Rita could probably answer that.

Q. Okay. Do you know how much -- how much did this particular study cost that you're doing? I know we heard before they're fairly expensive.

A. I'd have to get you that information.

Q. Has MDU received any preliminary information yet on that depreciation study, or is that just all delivered at once?

A. We haven't received any preliminary numbers, no. We're in the process now of providing

information so the consultant can do his work.

MR. HOBERG: Commissioner Clark, did you want a late-filed exhibit on that question?

COMMISSIONER CLARK: I'm sorry. Which question?

MR. HOBERG: The one about how much it costs.

COMMISSIONER CLARK: Yeah, that would be good, if you can provide it.

MR. HOBERG: Late-Filed 4, Mr. Pearce.

COMMISSIONER CLARK: That's all the questions I have. Thank you.

MR. HOBERG: Thank you, Commissioner Clark. Mr. Diller, please.

MR. DILLER: Just a couple.

EXAMINATION

BY MR. DILLER:

Q. Mr. Keller, do you have any knowledge of any agreements that the staff reached verbally with the company as to who was going to do the depreciation study? Do you have any knowledge of that?

A. I don't have any knowledge of that, no.

Q. Okay. I'd also like to add on to Commissioner Clark's late-filed exhibit, if it's all

right, the cost associated with supporting this 11-year-old depreciation study in this proceeding. Since it's going to be virtually obsolete in three or four weeks or a couple of months, whatever it is, I think that would be some information that the Commission might be interested in.

A. Could you rephrase that? Make sure we get what you're looking for.

Q. I just want to know what -- I want to know the total cost to the company to support the 11-year-old depreciation study in this proceeding. Had the depreciation study been done before this proceeding, we wouldn't have spent all this time and money talking about an old study that's not going to be worth anything in a couple of months. So I'd like to know what the total cost to MDU is to support.

A. Well, you know, to say it's not worth anything I think is kind of -- it's a study, but it was a thorough study that was performed and, you know --

Q. Did I hear you say -- I couldn't really hear. You said it real quickly. You said it wasn't done in time because you lost some information?

A. I said one of the reasons we can't get it

done as quickly as we'd like was because we didn't lose some information. Stone & Webster, who performed the last study, lost a lot of the data.

Q. So then if staff had hired a consultant then to do the depreciation study, since we had offers to do that in time for this proceeding, would we have had the same problem? Would we have --

A. It would have been difficult to give you the information. Again, Mr. Jeter may be able to better address this than I can, but I believe to do a thorough, detailed study, I think there's a lot of historical information you're using and, you know, I think there would have been -- to do a complete study, which we are expecting done, I think would have been -- you know, may have been difficult for your consultant to do in time.

Q. Do you understand the question? I'm asking for the cost of --

A. Yep.

MR. DILLER: Okay. I think that's all the questions.

MR. HOBERG: Thank you, Mr. Diller. Any further questions then of Mr. Keller? Mr. Pearce, any?

MR. PEARCE: No.

MR. HOBERG: Mr. Binek, please.

MR. BINEK: Just a couple other questions regarding this depreciation study.

RECROSS-EXAMINATION

BY MR. BINEK:

Q. When did MDU retain a consultant to do the depreciation study?

A. I believe we started looking for one about maybe April and we had -- I think he committed to us, I think, maybe in May. I'm not sure of the dates. And we asked him to complete the Great Plains study and then begin work and complete the Montana-Dakota gas study.

Q. Okay. Included with the late-filed exhibit 4, I would like to ask that any correspondence relating to the contract with -- is it AUS?

A. Yeah.

Q. -- concerning the contract and the contract itself be included in that exhibit.

MR. HOBERG: Mr. Pearce, can you do that?

MR. PEARCE: Well, I assume that's possible, barring some kind of a confidentiality provision that that consultant may have. I don't suppose there is, but I don't know of that, so with that possible proviso.

MR. HOBERG: Anything further, Mr. Binek?

MR. BINEK: No.

MR. HOBERG: Any further questions of Mr. Keller? Thank you, Mr. Keller.

MR. PEARCE: Can we take a couple minutes? We have some exhibits to mark for Dr. Gaske.

MR. HOBERG: Yeah. Let's take five minutes.

(Recess was taken.)

(Exhibit 31, 32, 33, 34, 35, and 36 were marked for identification.)

MR. HOBERG: We're back from recess, and you're taking the rebuttal of Dr. Gaske at this time, Mr. Pearce?

MR. PEARCE: Yes.

MR. HOBERG: Dr. Gaske, you testified yesterday. I'll remind you today that you're considered to be under oath still.

THE WITNESS: I understand.

MR. HOBERG: Mr. Pearce, please.

J. STEPHEN GASKE,

having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Dr. Gaske, you've prepared prefiled rebuttal testimony in this case, have you not?

A. Yes, I have.

Q. Rather than go through all the testimony, I'm simply going to ask you to summarize that testimony, if you will, and add any additional rebuttal points that you feel are appropriate after the staff's direct case.

A. I will try to go through and summarize my testimony, but I won't read the whole thing. But during the course of the summary I would like to direct the attorneys and the Commissioners to various points in the record, because in the course of summarizing this, I hope to lead you through the facts that have been introduced into the record so that, hopefully, you'll be able to follow along why I'm saying what I am and what the basis of the testimony is.

As a broad general overview there are really four big issues with regard to rate of return. One is the question of the flotation cost adjustment. Another is the comparable companies that we use in our DCF analyses. One is the growth

rate that we adopt, and the last is our assessment of risk. With regard to those four things, I advocate a flotation cost adjustment, which I'll talk about in a few minutes.

There's not a big difference between us with regard to the comparable companies. But there are some differences and there's some key factors that you need to understand. There are large differences between us with regard to the growth rate, and I believe very strongly that my growth rate analysis is based on relatively objective, publicly available information. In contrast Mr. King's is really based on a fairly subjective analysis that on its face appears to be fairly biased.

With regard to risk assessment I have two different opinions, depending on which proxy group you use. If you were to adopt the Moody's gas distribution companies as the appropriate proxy group, I believe that Montana-Dakota is slightly above average in terms of their risk. They're slightly riskier than the average company. If you were to adopt the companies that derive more than 75 percent of their revenues from gas distribution operations, then I believe Montana-Dakota is average

relative to that group.

So having said that, I want to walk through and summarize the rebuttal testimony. With regard to the flotation cost issue, it's very important, I think, to understand why you should be allowing a flotation cost adjustment. The standard that's used to evaluate whether a cost of capital or rather allowed rate of return is sufficient is often referred to as a capital attraction standard. That standard requires a rate of return that is sufficient to enable the company to attract capital on reasonable terms. Now, whether the company actually is going out and raising capital, whether it's growing, whether it needs new capital or whether it's built a system that is not growing at all, it still needs to have an adequate rate of return. And so the standard that was established to set that rate of return was this capital attraction standard. There also is a comparable earnings standard, but when we go to using a DCF analysis, we're really looking at a capital attraction standard.

When you set a rate of return based on DCF analysis, in theory you are finding the cost of capital that makes the investors indifferent as to

whether they invest in this plant or in this company and put utility assets in the ground or whether they put their money in U.S. Treasury bonds or CDs or anything else. In other words, it's exactly the amount of money they need to be compensated for the additional risk.

In theory that means that when they invest $1 in utility assets, the value of that investment will be $1. That will be the market value after it's in the ground, if everything goes well. If they do invest $1, though, and they have to raise equity capital to invest $1 in utility assets, they have to essentially raise more than that. They have to go out into the market and raise perhaps $1.05. The five cents goes to the investment bankers and then they have $1 investment in utility assets.

Consequently, the rate of return needs to be adjusted to reflect the cost of flotation. It doesn't mean the company is going to go out and issue common stock. It doesn't mean that it's done so recently. It means that in order to be in a position to attract capital, in my opinion, to meet the capital attraction standard, it has to have a rate of return so that it can go out and issue that common stock without diluting the existing

investors' investment. I put together a numerical example of this concept that I'd like to hand out as an exhibit. It a little bit complicated, and I won't spend too much time on it, primarily because I think you'll fall asleep if I do.

MR. HOBERG: Is this 31?

MR. PEARCE: Yes.

THE WITNESS: Have you handed them out to everyone?

COMMISSIONER REINBOLD: What number is that?

MR. PEARCE: 31.

THE WITNESS: The general assumptions here are that the company has existing equity of $100, book value of $100, and it has a rate of return that is exactly equal to the investor requirement as determined by a DCF analysis. Under those circumstances, the market value should be $100. The number of shares outstanding is 100, so that the existing investors will have a book value of $1 per share and they have a market value of $1 per share. And I've put $1 into plant and that's what it's worth in the market. If they require a rate of return of 15 percent, they would get $15 of return. And that's what this shows across the first line of

numbers there.

If the public utility then goes out and issues new common stock because it needs to build new plant, and it issues $100 in new common stock, under the example here that I have, I've assumed that the investment bankers take 10 percent of that. They take $10. So the company issues $100 in common stock. They raise $100. $90 of that gets invested in a utility plant that's allowed to earn a rate of return. If they earn exactly the 15 percent required, the utility -- the new utility plant will have a book value of $90 that will go into the rate base. The market value will also go up by $90 because they're earning exactly their allowed rate of return. The number of shares outstanding has now doubled. They issued 100 shares all at $1 apiece. But they got net proceeds of $90 so they have 200 shares outstanding now and the new book value is 95 cents per share. And the new market value, if they are earning 15 percent, is also 95 cents per share.

The impact on the existing shareholders is that they were sitting there with stock that was worth $1 and now their stock is worth 95 cents. The reason being is that the company went out and built a utility plant and raised new common equity to

build that plant and was left with only $90 that they could put in their rate base, even though they had to issue $100 worth of common stock. The effect was to dilute the existing investors' return and the value of their stock. If they earn a 15 percent rate of return, the new larger company would have -- in the last column it shows that the new larger company would make $28.50 a year. They get a 15 percent return on the plant that's in the rate base, but they get a zero percent return on the flotation costs that they incurred.

And just in this example, instead of getting a 15 percent rate of return on all of the dollars that were spent, they get a 14.25 percent rate of return. They don't get the 15 percent that the DCF analysis told you that they required. They were not in a position to issue new common equity on reasonable terms without diluting the value of the stockholders' investment.

The second example I have here is a flotation cost adjustment where you increase the allowed rate of return by 10 percent. You multiply 1.1 times the 15 percent that investors require. That comes out with an allowed rate of return of 16.5 percent, which is more than what investors

require, but the goal here is to increase the market value above the book value by 10 percent. Here, if you look at the first line of the second example, you have a book -- starting book value of $100. Because you've applied a flotation cost adjustment, the market value is actually $110. So the market value is actually worth more than the book value. And with 100 shares you have $1 in book value and $1.10 in market value per share.

Now, when the utility goes out and says we need to build new plant, we need to raise common equity to invest in new plant, they sell 100 shares of stock for $1.10 because that's the market value of the stock. They raise proceeds of $110. $10 goes to the flotation costs. That ends up going to the investment bankers. And they're left with $100 that they can invest in utility plant. So by issuing the new common stock, they can add to their new plant by an amount of $100. That new equity if it has an allowed rate of return -- or I'm sorry. They add to their existing plant an amount of $100. If they get a 16.5 percent rate of return on that, it should be worth $110.

In total now, the company has 200 shares outstanding. They have $200 in their rate base

that's earning a return, and they have a market value of $220. The market value is higher than the book value in this case because you've made a flotation cost adjustment. The price per share and the book value per share is $1. $1 for the book value and $1.10 for the market value. You can see that those numbers are the same after the issuance as before the issuance.

The existing shareholders don't lose anything by virtue of the fact that the company has issued common stock. So the company is able to issue the common stock on reasonable terms without diluting the value of these existing shareholders' investments. That -- I don't think I'll walk you through the rest of it because it's a similar example down below.

The last example is just a much larger stock issuance, but the result is the same. You start with a book value of $1. You have a market value of $1.10. You're able to issue common stock and still -- the existing shareholders are still in the same position they were before.

Now, the question is, if the company has not been issuing common stock in recent years, why do you allow this? It's not because they need to be

compensated precisely for what they have just issued in the last year. It's not because they need to be compensated for what they know; in fact, right now they're going to earn next year. It's because the company needs to be in a position to do this at all times. It's a little bit like insurance. I didn't have a car accident last year, so why do I need insurance this year? I didn't have to raise capital last year. Why do I have to have a flotation cost adjustment so I'll be in a position to do so this year? That in essence is what the issue is about.

I mentioned in my rebuttal testimony that a number of other economists advocate exactly the same kind of adjustment. It's not an unusual thing. It is supported by the economic literature. Mr. King has indicated that the company's experience in the recent past has been that flotation costs have been 0.1 percent of the capital rates. That's actually very misleading, because, in fact, that's not what the flotation costs have been on the capital that has been raised.

Let me give you the biggest area where that becomes misleading. Mr. King has noticed that the company issued about $400 million worth of shares to buy other companies. Well, that's not raising

capital. You don't have big flotation costs to swap shares with someone. It's just a share swap. No cash was raised that could be used to go out and put mains in the ground for the public utility customers. Transactions like that don't have very big flotation costs associated. So you really can't include that in the concept of what does it cost this company if it were to have a need to go out and raise cash for the utility operations. The recent historical experience for the company is shown on page 5 of my rebuttal testimony, at lines 12 to 15.

COMMISSIONER WEFALD: Which page, please?

THE WITNESS: Page 5. In recent years the company has raised $157 million. It incurred flotation costs of 5.2 million and the flotation cost adjustment or the amount of flotation costs was 3.43 percent of the net funds that they raised. So that's been their recent experience. If they had no recent experience whatsoever, they would still need a flotation cost adjustment. If they had raised lots of money recently, they would need one on a forward-looking basis. Because this is much more of a concept similar to the idea of risk where it's a forward-looking thing where you need to be in a position to do so at all times.

The study that I've done that appears in my direct testimony was to look at many gas distribution companies and the costs that they have incurred in the past. And I came up with an average of about 4.85 percent as the average for gas distribution companies in terms of the flotation costs. I recommended in this case an adjustment of 4.75 percent as being on a forward-looking basis what the company might on average expect to incur. Sometimes they might get less than that. Sometimes they might have to pay more. And it's just depending on conditions in the market at the time.

I guess to summarize, there is a need for the flotation cost adjustment. Mr. King's adjustment of 0.1 percent does not reflect what it costs to raise capital, and I'll leave it at that on that issue.

The next issue I want to talk about is the proxy group. I have another exhibit to show you. Essentially --

MR. HOBERG: Are you offering 31?

MR. PEARCE: I'll offer it now.

Q. (MR. PEARCE CONTINUING) Dr. Gaske, did you prepare Exhibit 31?

A. Yes, I did.

MR. PEARCE: I'll offer Exhibit 31.

MR. HOBERG: Mr. Binek, any objection?

MR. BINEK: No.

MR. HOBERG: Exhibit 31 is admitted. Please continue, Dr. Gaske.

THE WITNESS: The next exhibit is Exhibit 32.

MR. HOBERG: I've got that here for the Commissioners.

THE WITNESS: I just noticed that there's one thing that's not correct here and that's in the sources I have bond ratings. And, in fact, there are no bond ratings on this page. I had carried that over from a copy of another exhibit. So --

COMMISSIONER WEFALD: Cross that out?

THE WITNESS: -- you can cross that out. The other source is the percent gas distribution, and with one exception that was taken from Mr. King's testimony. The one exception is Keyspan. And if you'll recall yesterday, an exhibit was introduced that showed it was from the Keyspan 10-K and it showed their percentage of revenues from gas distribution and I was asked about that percentage. I did not calculate it in my head, but I went home last night or back to the hotel and calculated 54.5

percent. So it's at the bottom there.

These are the proxy companies that Mr. King and I have used. They're all put together. We have used two different groups. I've used the Moody's gas distribution group. It's a group that I've used routinely in the past in gas distribution cases. The companies in that group are marked with an X here. It's commonly used as a group of companies that are representative of the gas distribution industry and people look at this group for information in general about the industry.

Each of the companies is included in Value Line as being a gas distribution company. Each of the companies is also included in the CA Turner Reports as being a gas -- or gas distribution or integrated gas company. So they are widely perceived to be gas companies. I believe it's appropriate to use these companies for a DCF analysis. It is something -- as I note in my testimony, Mr. King used the same companies about a year ago before this Commission.

Mr. King has proposed an alternative proxy group. And that's companies that derive at least 75 percent of their revenues from gas distribution companies -- or gas distribution operations. The

percent gas distribution column, as I said before, is taken right out of his testimony. You can see that the companies that meet the standard that he established include all of the companies down to Peoples Energy Corp, which derives 80 percent. So actually all of the companies that really meet the standard derive not just at least 75, but derive more than 80 percent from gas distribution.

Mr. King has proposed to also include WGL Holdings, but in my rebuttal testimony I asked the question since they didn't meet his criteria, you know, why would you include it? So that in essence is -- if you want to look at the companies and the criteria that were used to select them, that compares our two groups and accounts for some -- to a small extent some of the differences between the two of us in our studies.

The next area that I want to talk about is the growth rate differences between the two of us. And to help you in the discussion of this, to help me in the discussion of this, I've prepared another exhibit. I know it's been marked as Exhibit 33. Since I'm leaving 32, is there anything --

Q. (MR. PEARCE CONTINUING) Are you finished talking about 32?

A. Yes.

Q. And did you prepare Exhibit 32?

A. Yes, I did.

MR. PEARCE: I'll offer Exhibit 32.

MR. BINEK: No objection.

MR. HOBERG: Exhibit 32 is admitted.

THE WITNESS: The data on Exhibit 33 attempts to do an apples-to-apples comparison between Mr. King's study and my study and other alternatives that have been discussed on the record, as well as alternatives that I have included in my rebuttal testimony. The first column of numbers shows the average results from various studies using various growth rates. My -- and I should say that column is what I refer to as the investor return requirement. It does not have a flotation cost adjustment. The cost of capital after flotation cost adjustment is shown in the last column, but for purposes of this discussion and comparison, I'm really going to focus on the first column.

My second stage retention growth method, which was conducted on Moody's gas distribution group, came up with a 12.83 percent rate of return on average. That simply is a weighted average, two-thirds of the weight on the Zacks analyst

estimate and one-third on the book value growth rate -- or, actually, the earnings retention growth rate.

The second one is the basic study. That's identical to what Mr. King refers to as a classic study, where you simply add the Zacks growth rate estimates. The only difference between us really comes about because we have different companies in our proxy groups. The primary one in my study was one that I looked at the results, I made some subjective judgments and came up with an average of 12.63 percent. And you can see where I made my subjective judgment, my average rate of return actually comes in below what either the second stage retention or the basic came in at. And that was very specific to the companies in the Moody's gas distribution group.

The next group, going down the list, is really derived from cross-examination yesterday when I was on the stand. I was asked what would the average results be if Keyspan and Laclede were removed from my groups, and I couldn't calculate the average in my head, but -- exactly. I think I had some ballpark number, but my second stage retention results would have been 11.75, and my basic would

have been 11.51. Now, I believe that it is appropriate to include Keyspan and Laclede in the results, but these are some numbers that you have before you in the record and when you sit down to consider rate of return, you're going to be looking at these numbers and having to weigh them against the others. I really do believe that those two companies should be included in the group and so you can take those numbers for whatever they're worth. I don't put lots of weight on them.

The next set of numbers are numbers that appear in my rebuttal testimony. I would direct your attention to Exhibit JSG-4, which are the exhibits that are attached at the back of my rebuttal testimony.

MR. HOBERG: JSG-4?

THE WITNESS: Yes. Schedule 1 in particular.

COMMISSIONER CLARK: Which page?

THE WITNESS: I'm sorry. Schedule 1, pages 1 and 2.

Here what I've done is to simply take the companies that meet Mr. King's criteria. They derive at least 75 percent of their revenues from gas distribution based on his numbers. It includes

all of his companies, except Washington Gas Light or WGL. I've used his Zacks numbers, his stock price, his dividend, and his book value per share with the growth rate. The average Zacks growth rate for these companies is 6.38 percent and the average of Mr. King's estimates of the book value growth rate is 7.14 percent. I've taken a weighted average of those two, giving two-thirds weight to Zacks and one-third to the book value growth and come up with an overall weighted average growth rate. I've then taken his stock price and dividend data and adjusted the dividend yield for the .625 dividend adjustment factor that has been somewhat notorious in the case.

And so I've done this in an objective way that matches up with my second stage retention growth method of really taking the information from both of these growth rates and combining them. And I come up with an average of 11.8 percent without flotation costs and 12.4 with. So if you do what I think is much closer to a proper analysis of the growth rate, you would come up with at least 11.8 percent for these companies.

The next page is virtually identical. It's all Mr. King's data and just taking a weighted average and I come up with a -- when I weight book

value growth and Zacks equally, 50-50 for both, I come up with 12 percent for these companies. And those are the numbers and that's the approach.

The last group of figures that I want to talk about are from Mr. King's analysis. His first DCF analysis is based on his book value growth rate. And for his companies, which also included WGL Resources, he came up with a 12.18 percent return and that comes from his testimony on page 20. It's table 7 on that page. Now, you can see the 12.18 percent return in table 7. Immediately thereafter on pages 20 and 21, he indicates that he really doesn't think that this is representative of what investors expect, primarily because for the 11 companies in his analysis, Value Line does not project that their earnings are going to go down in the future.

Well, in fact, if these companies had negative growth rates, nobody would be buying them. He also thinks that Value Line is biased because they project that all 11 companies are going to have increased earnings in the future and they're going to maintain or even increase their current rate of return. So he pretty much discounts and rejects this data. The theory is that Value Line is biased.

Yesterday, in cross-examination of Mr. King, sheets from Value Line were introduced. It showed that Value Line indeed does project declining earnings, declining return on equity for companies. They're not biased. When they believe that a company's earnings are going to go down and its rate of return is going to go down, they do project that. The fact that you can look at these 11 companies and say, gee, they're going to grow in the future is not at all surprising. That's what you expect. That's what the Zacks analysts expect. That's what investors would logically expect for those companies. That's what you expect out of most companies. So at this point in time, you can't take that information and say, well, that means they're biased, just because they think the companies are going to grow or maintain their current rates of return. So Mr. King gives very little weight to the book value analysis, but when you really look at his reason for giving little weight to it, it doesn't make any sense.

He has a historical analysis which is based on historical growth rates. That appears on page 22 of his testimony in table 8. Here, his average rate of return is 11.72 percent. Now, when you look at

table 8 fairly closely, you can see that there's some pretty wild swings. There are some companies that in the past, in the very recent past, have had negative growth rates. No one would actually expect that to be the case in the future. And he has Southwest Gas with a positive 37 percent growth rate, and I don't think you can really expect that to happen in the future, either. These are kind of wildly out of line.

My rebuttal testimony discusses the fact that you really can't give much credence at all to these historical results. Certainly, Value Line, when it does its book value projections, book value growth projections, they were aware of this historical data. The Zacks analysts, when they did their projections, they were aware of this data. I'm sure they took it into consideration. So you really don't have a whole lot here on historical growth numbers typically because they were fairly short periods of time in the past to do much with. But, nevertheless, he has these numbers and he does place some weight on them.

His last approach, the classic approach is that -- that appears on page 23. And I'm sorry. The summary of the three-year results appears on

page 23. The actual analysis appears on page 18, table 6. And here you can see that the average rate of return was 11.29 percent. And that's very straightforward. It's just adding the Zacks analysts' growth forecasts.

One of the major places that I think Mr. King's analysis is flawed is in how he's taken this information and used it subjectively. He says that he started with the classic result, 11.29 percent. And from that he then looked at the book value results. They're a whole lot higher. So he considered those and worked those into the calculation, these much higher numbers. He also took the historical results, also quite a bit higher. So after he gets finished including these higher numbers in his results, he comes up with a lower average on its face that just doesn't make a whole lot of sense.

Now, he says that he went company by company and really analyzed each company individually and described why he did what he did, but the fact of the matter is, is that the level of bias is pretty high when you consider that after consideration of much higher numbers, he ends up with a lower number than he started with. That

gives him a 11.23 percent rate of return. You, as Commissioners, will have to decide out of this evidence that's in the record which of these numbers are credible and which ones to place true weight on. And I would say that, in my opinion, the 11.23 number doesn't make any sense whatsoever.

To the extent that you place any weight on the numbers and evidence that he has put in the record, the recalculation that I've done that gives very explicit consideration to both Zacks and the book value growth rate; the two-thirds/one-third or the 50-50 analysis. They come out pretty close to each other; 11.8 percent or 12 percent before flotation costs. Those at least you can trace mathematically. You can debate whether or not the assumptions are correct and actually have some reasonable basis for decisionmaking.

Now, yesterday I talked about the fact that I generally believe that book value is a floor for your long-term growth rate. I think Mr. King agrees with me on that, but then he ends up saying that he really considers book value to be a ceiling because it has the highest number. But if you look at page 19, lines 5 to 13 of his testimony --

COMMISSIONER WEFALD: 15 to 19 of his

testimony?

THE WITNESS: Page 19, lines 5 to 13.

There he says that the book value growth model is less useful for gas utilities than it used to be for two reasons. One, is that these companies are somewhat diversified. They don't just get their income from regulated operations. The other is that he thinks very few utilities are so closely regulated that the only source of growth in earnings is the increase in book value. Now, I agree with both of those statements. They parrot exactly what I said yesterday when I was on the witness stand.

What these two statements say is that these companies have some unregulated operations so book value growth is not necessarily the best indicator of their growth rate because they have ways they can grow even faster than that. So later in his testimony or around this point in his testimony where he says that book value is a ceiling, the reasoning he has in his own testimony suggests, indeed, that it should be a floor, which is what I think. So when you're looking at his testimony and looking at the 12.18 percent book value and the reasons that he gives for rejecting it, I think you'll find that the record shows that they're not

particularly good reasons, that they don't actually fit with the reasoning of his own testimony. That's one reason in addition that I really don't give a whole lot of credibility to that 11.23 percent that he came up with subjectively.

If you look at the ultimate results he comes up with subjectively, which appear on page 24 of his testimony in table 10, he has his 11.23 number there, and these are his kind of subjectively derived numbers. The range of rate of return there is 9.5 percent to 14 percent. If you go back to Exhibit JSG-4, Schedule 1, that's at the back of my rebuttal testimony, and looking at Schedule 1, page 2 of 2, that's the 50-50 weighting. The range of returns on that exhibit is 9.53 to 14.09. In essence, it's virtually identical to the range that he has in his ultimate DCF analysis. But the average is very different. The average for the group is 12 percent. So I would submit they're not enormous differences between us, but somewhere in the course of making some subjective adjustment, he's come out with a very low number that just is not reflected by the record.

I believe that Zacks growth rate and the book value growth rate should both be given at least

some serious consideration, should both be reflected, and that the appropriate growth rate is somewhere between the two, not below either of them. So having said that --

MR. HOBERG: Commissioner Wefald.

COMMISSIONER WEFALD: On Mr. Gaske's -- now we're about page 10 of his 29 pages of testimony. How much longer is he anticipating going, because I do want to make sure that we have a chance to ask questions of the other people who are here and have a chance to hear the other presentations?

THE WITNESS: I think I've gone through the really detailed parts. It won't -- I don't think it will be nearly as long to do the last.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: The next area that's fairly important is the risk assessment. Mr. King believes that the company, Montana-Dakota Utilities, is a relatively low-risk operation. His primary reason for saying that is that Montana-Dakota Utilities is a part of a very large company. Now, yesterday he gave an example of Atlanta Gas Light, who lost a customer and, you know, obviously had some risk there.

The thing about Atlanta Gas Light is that

in my direct testimony I have evidence that compares the size of Atlanta Gas Light to the size of Montana-Dakota's gas distribution operations and that appears on JSG-2, page 1. And it looks like Atlanta Gas Light's assets are 3.3 billion as opposed to Montana-Dakota's gas distribution assets of 183 million. The operation operating income for AGL was 209 million, but Montana-Dakota's gas distribution operating income was $4 million, an enormous difference in size. For AGL, with a large territory, a very large population, that it serves, it can lose major customers and it will hurt AGL. Montana-Dakota, on the other hand, can be hurt much more if large companies, large operations leave its service territory leaving people unemployed, and perhaps stranded facilities behind or other impacts along those lines.

It's interesting, his argument on the small company issue, because one of the reasons he says Montana-Dakota has low risks is that we're only looking at the gas distribution operations. We're looking at them as a stand-alone operation and they're 100 percent gas distribution, whereas these other companies are diversified, at least to some extent, and at that part of his testimony he says,

essentially gas distribution is less risky than a diversified company. However, when he gets to the small company issue, he says, well, actually, these gas distribution operations of Montana-Dakota, they're part of a great big company.

So there's a direct contradiction there in what he's saying. On the one hand, the company is low risk because we'll look at it on a stand-alone basis, 100 percent gas distribution business. On the next hand, it's also low risk because it's part of a larger holding company with other operations so we'll look at it on a consolidated basis for that issue. Two diametrically opposed positions on the risk when analyzing risks in different situations, but both of those positions lead to the same conclusion, low risk, at least in his mind.

Now, one of the things that he talked about yesterday was, for example, competition. All of these companies, including Montana-Dakota, face competition. So it's not a major factor to distinguish them. He talked about Washington Gas Light in particular, and I have another exhibit and I won't spend too much time on it, just to introduce it into the record, but I went on the Washington Gas Light Website because I happen to be a customer of

theirs. I know something about what happens in their service territory and what has happened in the past.

This Exhibit No. 35, which I think was just --

MR. HOBERG: Exhibit 34?

THE WITNESS: I skipped over 34 in the interest of saving time.

MR. PEARCE: While we're paused for a moment, I'd like to offer Exhibit 33, which I didn't do before, the DCF summary.

MR. HOBERG: Okay.

THE WITNESS: In the late '70s and early --

MR. HOBERG: Just a minute, please.

Mr. Binek, any objection to 33?

MR. BINEK: No.

MR. HOBERG: 33 is admitted then. You skipped over 34, Dr. Gaske?

THE WITNESS: Yes, I did.

MR. HOBERG: Are you still offering 34?

THE WITNESS: Yes, I think I'll mention it very quickly at the end.

MR. HOBERG: Okay.

THE WITNESS: In the Washington, D.C. area a lot of new homes were built with electric heat

pumps in the late '70s and early '80s. It was a relatively new type of appliance. The cost of gas at that time was over $4 a decatherm. On an inflation-adjusted basis we're probably talking about $12, $15, and new homes were being built with these heat pumps. The thing about the heat pumps is that they didn't really work very well. My parents have one and they have heavy sweaters that they wear all the time. People figured that out and not a whole lot of heat pumps are being put in place. The price of gas relative to electric heating has come down considerably since then.

On their Website they talk about the fact that they have an active program for conversions. A lot of people who bought houses that had heat pumps in them are converting. In their Website they say that for gas heating, gas heating is preferred 4 to 1 in their service territory. They have about 80 percent of the heating market. They also in the same exhibit say that 9 out of 10 new homes in the metropolitan area are heated with natural gas.

COMMISSIONER WEFALD: What is the relevance of this exhibit?

THE WITNESS: The relevance is that yesterday we were told that, well, the proxy

companies really face a great deal more competition than Montana-Dakota does. Montana-Dakota faces competition, potential competition from propane. This company faces competition from electric heat pumps. And I wanted to place this in context, that, in fact, they're winning 90 percent of the new business. So they do have competition, and I don't dispute that. Montana-Dakota has competition, and I don't dispute that, but it's really a matter of what degree and how much weight do you give that competition in distinguishing between the companies.

MR. HOBERG: Are you offering Exhibit 35 then?

MR. PEARCE: Yes.

MR. HOBERG: Any objection to Exhibit 35, Mr. Binek?

MR. BINEK: No. I think it's kind of what we were trying to establish yesterday.

MR. HOBERG: Okay. 35 is admitted.

THE WITNESS: Okay. The last exhibit that I want to introduce is the bond ratings for the companies in Mr. King's proxy group. Now, Mr. King says that Montana-Dakota has very low risk relative to these companies, but when you look at the bond rating, it's right about at the average or the

median of the group. It's not exceptionally low. What's interesting about this is that, as he and I both discuss, Montana-Dakota has at least for this -- in this filing and for the utility operations they have a higher equity ratio than many of the other companies. I maintain in my rebuttal testimony that, in fact, they have slightly or somewhat above average business risks. So you have financial risks represented by the capital structure and you have business risks also in there.

When you put the two together, the company has about average risks and that's borne out by these bond ratings, which reflect a combination of both business and financial risk. In my direct testimony, as I said earlier, Montana-Dakota's first mortgage bonds have a lower average rating than the Moody's gas distribution group. And my overall assessment of that group indicates to me that they have above-average risk relative to that group, but relative to Mr. King's proxy group, they have essentially average risk and that's supported in part by these bond ratings, that they have a higher equity ratio, but I think they have higher business risk.

One of those risks is the fact that they're

small. In his testimony Mr. King at one point, and I want to direct you there, but he says, for example, Southwest Gas may be actually less risky because it's growing rapidly. Well, in Montana-Dakota's service territory there's little or no growth at all and, in fact, if you look behind what's going on a little bit, they have customer growth of about 1 percent per year, but a lot of that is people moving out of small towns to the larger cities. So you have a situation where they're needing to expand facilities in the city, but they still have costs that they have to recover in the smaller towns that factor declining population. And in the long run that's a problem for the company.

Mr. King indicates that a fast growing company like Southwest Gas has low risk. Well, when you -- I talked about this in my rebuttal testimony. If you look at Montana-Dakota, it's at the other end of the spectrum.

I have some additional things in my rebuttal testimony. I demonstrate that the premiums between Baa bonds and U.S. Treasury bonds are the highest now they have -- or just about the highest they have been in 10 years, other than briefly after

September 11th. The force and weight of that is that Mr. King has some testimony where he takes the rate of return that's been allowed in some past periods and says, well, here's what the treasury bond rates were then and here's what the treasury bond rates are now, but Baa bond rates are much closer in risk to the common stock of a gas distribution company. And the higher the risk, the bigger the premium. And we talked about this at great length yesterday so I'm not going to go any further than that.

But if you really look closely at the question, I believe that this increase in the risk premium required by investors probably indicates that if you use the past allowed rates of return as a benchmark, you probably ought to have even higher rate of return now, but that's just as a benchmark. The real heart and soul of both analyses are the DCF analyses, and, hopefully, I've helped you understand what the difference is between the two -- between the two of us on that issue.

MR. HOBERG: Thank you, Mr. Gaske. Did you want to offer 34 and 36?

MR. PEARCE: 36, I would offer.

Q. (MR. PEARCE CONTINUING) Did you want to

say something about Exhibit 34, Dr. Gaske?

A. Yesterday I was asked various questions about, I believe it was Exhibit 11 that was introduced that showed returns over a long period of time. Exhibit 34 looks at Ibbotson data, and it finds that when you do a statistical analysis of the difference between bond returns and stock returns, you're assured that there's a difference at a level of about 99.93 percent. And that shows up on the last page of it. I won't go into a lot of detail on the statistical techniques and things like that, but that's the correct way to analyze something like that.

I looked at the average difference between the two and I found what you would expect, that the probability that the premiums are higher than average is 50 percent and the probability that they are lower than average is 50 percent. In other words, the historical premiums do represent the best estimate of what kind of premiums have been available over a long run in the market. And the questions yesterday about standard deviation and mean, I believe were really off point for whatever point ultimately is to be made with that data. So I put this in the record to have what I believe is a

more appropriate analysis.

MR. HOBERG: Thank you. So you're offering 34?

MR. PEARCE: I'll offer 34 as well.

MR. HOBERG: Any objection, Mr. Binek?

MR. BINEK: No.

MR. HOBERG: 34 and 36 are admitted. Any further questions then, Mr. Pearce?

MR. PEARCE: Did I formally offer the written testimony, Exhibit 24? I don't show that yet. I'll offer that at this time.

MR. HOBERG: Any objection to the formal written rebuttal testimony of Dr. Gaske?

MR. BINEK: No.

MR. HOBERG: Exhibit 24-54 is admitted. You have no further questions?

MR. PEARCE: No.

MR. HOBERG: Mr. Binek, do you have a number of questions?

MR. BINEK: It might be a good time to take a little bit of a break and we may be able to shorten our questions.

MR. HOBERG: I think all of the witnesses, next witnesses and the questions regarding all the next witnesses maybe you want to look at to see.

I'm assuming we're going to get done at 5:00. If that's the goal, then we're going to have to look at ways to do that. So let's take five minutes right here.

(Recess was taken.)

MR. HOBERG: We are back from recess and completed the direct of the rebuttal of Mr. Gaske. Mr. Binek, do you have any questions on cross-examination?

MR. BINEK: Yes, I do have a few. Been able to eliminate a number.

MR. HOBERG: Good.

CROSS-EXAMINATION

BY MR. BINEK:

Q. First of all, referring to your exhibits, how many of these exhibits could have been introduced with your rebuttal testimony?

A. All of these exhibits were prepared last night or subsequent to the filing of my rebuttal. Except for maybe one, all of them were prepared last night in response to various things that Mr. King had to say yesterday.

Q. Based on the record here, they could have been prepared prior to that?

A. Some of them could have been, but the ones

that could have been really reflect information that was available in the record. Some --

Q. Okay. It doesn't matter that much, anyway.

A. There really wouldn't have been any reason to introduce them until I heard Mr. King's rebuttal or surrebuttal yesterday where he discussed a number of things that were in my rebuttal testimony.

Q. Okay. Your Exhibit 31 assumes a market-to-book ratio of 1; isn't that correct?

A. Yes.

Q. Do any of either yours or Mr. King's comparable companies have a market-to-book ratio of 1 or less?

A. No.

Q. In fact, don't all of these companies have market-to-book ratios higher than 1?

A. The same principle that's shown in there still applies but, yes. Yes, their market-to-book ratios would go down if they were to issue common stock, and so the value of their other assets would go down.

Q. When a company sells new stock at a market value greater than book, what does that do to the book value of the existing stocks?

A. It increases the book value of the stocks.

The book value for original cost of the plant, if it puts it in utility plant, will be equal to the proceeds, and the market value, as I show there, will go down.

Q. Now, going to Exhibit 32, if you round WGL Holdings percentage gas distribution to the nearest percentage point, what do you get?

A. 75 percent.

Q. Okay. Had you included WGL in -- what is it -- pages 1 and 2 of Schedule 1 of JSG-4, what would it have done to the 11.8 percent you show?

A. It would have made it approximately 11.6.

Q. So it would have reduced it?

A. Yes, if you included it.

Q. Where does Mr. King say he places weight on his historical DCF returns? Perhaps if you look at page 22 of his testimony at the bottom.

A. I'm at page 22.

Q. Well, in fact, doesn't he say exactly what you've said about historical results on pages 23 and 24 -- or 22 and 23?

A. He says -- yes, he says that in general.

Q. Okay. Thank you.

A. Well, actually we can handle that on brief, because I can't find the passage right now that

would answer your original question.

Q. Okay. I'd like to have you turn to page 23 of Mr. King's testimony. Are Mr. King's book value growth results always higher than the classic returns?

A. No.

Q. Did Mr. King use book value growth as a ceiling in all cases? We're referring to table 10.

A. In some cases, yes. Some cases, no. Actually, you shouldn't say that. On table 10 it's not really entirely clear where those numbers come from. They are really his subjective decisions, and earlier in his testimony he says why he considers it to be a ceiling.

Q. But the question was, did he use book value growth as a ceiling?

A. Some of those numbers are higher than the book value growth rate for its individual companies, yes.

Q. Do you recall Mr. King testifying as to the number of customers AGL has, and do you know how many they have?

A. Now, it depends on which part of their operation. He said that AGL has 11, but, in fact, obviously Atlanta Gas Light has, I would guess, more

than a million.

Q. You're certain of that? Do you know who it markets to?

A. Now, are you asking how many customers the utility has or how many gas marketing customers they have?

Q. It's one and the same.

A. Actually, that's not true.

Q. Well, how many gas marketing customers does it have?

A. Well, yesterday he said that they had 11, but it's a gas distributor that serves, you know, people all over the Atlanta area.

MR. BINEK: No further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Wefald, do you have any questions?

COMMISSIONER WEFALD: No, I have none.

COMMISSIONER CLARK: I have none. Thank you.

MR. HOBERG: Mr. Diller, no questions? Any additional questions, Mr. Pearce?

MR. PEARCE: No.

MR. HOBERG: Nothing further then of Dr. Gaske. Thank you, Dr. Gaske. Next witness, Mr. Pearce.

MR. PEARCE: Call Rita Mulkern.

MR. HOBERG: Ms. Mulkern, you, too, testified yesterday so I just need to remind you that you are still under oath.

THE WITNESS: Yes.

RITA A. MULKERN,

having been previously duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Ms. Mulkern, you have prepared and had prefiled in this case written rebuttal testimony, have you not?

A. Yes, I have.

Q. Is that Exhibit 25? You don't have it there. It's been marked as Exhibit 25.

MR. PEARCE: I will offer that at this time.

Q. (MR. PEARCE CONTINUING) And ask Ms. Mulkern if she could please summarize her testimony.

MR. HOBERG: Any objection to Exhibit 25 -- actually 25-55?

MR. BINEK: No.

MR. HOBERG: No objection. Exhibit 25 is

admitted.

THE WITNESS: I'll summarize my testimony. What I would like to do is to address certain adjustments proposed by Mr. Majoros; namely, the amortization period for rate case expense, the adjustment to other operating and maintenance expenses for inflation, a statement he made concerning the increase requested, and the price of natural gas. And a statement concerning the reasonableness of the increase in the operation and maintenance expenses.

On page 15, line 18 of his testimony, Mr. Majoros proposes a five-year amortization of rate case expense, rather than the three-year amortization proposed by the company. And the sole rationale he uses for setting a five-year is the time period between rate cases. And I presume he's referring to the fact that it has been eight years since the last rate case.

However, just because it's been eight years since the last rate case does not mean it's going to be another five years before the next rate case. We were able to refrain from filing during that time period because we took action to increase our operating efficiency and reduce costs rather than

coming in and seeking a rate increase. And Mr. Fox testified yesterday and specifically talked about some of these measures that we took. He also talked about how we'll continue to strive for operating efficiency and cost reduction, but it is not anticipated that we can replicate our past performance and stay out for -- refrain from filing for another five years. We believe that a three-year amortization provides the best time frame for rate case expense.

Alternatively, if the Commission decides that a five-year amortization is appropriate, then the unamortized portion of the balance of that rate case expense should be included as a rate base addition. And the reason for this is that we're spending the money on this rate case. The cash is going out the door today, 2002. With a five-year amortization, the cost will not be fully recovered until the end of 2007 and, therefore, rate base additions will compensate for that time value of not recovering it -- excuse me -- putting in a rate base will give us a return on that component to compensate it for the length of time it takes to recover the cost.

On page 16 of his testimony Mr. Majoros

proposes to eliminate the inflation amounts from the other operating and maintenance expenses. And he gives his reasons not to allow these because they have not been previously allowed and because he recommends that we not be starting now. Mr. Majoros appears to be missing the point of this adjustment.

In this case we're using a projected 2003 test period. And in projecting out costs for 2002 and 2003, costs were broken down into major categories and these major categories are listed on -- I believe the statements are Exhibit 2, Statement N, page 14. And there we list those items adjusted individually. And those items were labor, benefits, insurance, advertising, and rate case expense. Those adjustments made up 71 percent of the total operating and maintenance expenses for North Dakota gas operations. The remaining 29 percent of costs are real costs incurred by the company and they're not likely to remain flat just because they weren't adjusted individually. This category includes such items as materials, postage, vehicle and work equipment expense, uncollectible accounts and some others. And to adjust these upward, we used a three-year average of the Consumer Price Index.

The last time this Commission addressed inflation factor in our case was in July of 1991, which was over 11 years ago. Now it is time to recognize that these costs are real costs. They are subject to inflationary pressures, just as the costs we adjusted individually were. For example, we know that postage expense went up July 1, 2002 and overall the increase in our postage expense was about 7 1/2 percent. This postage expense was included in that inflation adjustment, so, if anything, our inflation adjustment could be understated because of that. So the proposed inflation adjustment should be allowed.

And now I'd like to just address a couple statements Mr. Majoros made. First, was on page 2, lines 11 and 12 of his testimony, he made the comment that proposed increases will be superimposed on those already resulting from spikes in the market price of gas. Now, that's a very general, broad statement, and is not supported by the evidence. Montana-Dakota's gas cost has been very stable over the long term, with the exception of the winter of 2000-2001 where there was a large spike in gas costs, not only here in North Dakota, but it was seen nationwide.

Exhibit No. 26 -- or 25 is a graph. Excuse me.

MR. PEARCE: RAM-2, Exhibit 25.

THE WITNESS: 25 is a graph showing the history of gas costs for North Dakota's gas customers, the amount included in their rates through the monthly purchased gas cost adjustment, and this graph is shown for the period of January of 1999 through October of 2002. Now, you can look at the graph and you can see that gas costs, with the exception of that 2000-2001 time period have been very stable and, in fact, they have been slightly lower in 2002 than in previous years. So there have been no spiking gas costs, other than one winter here.

In addition, Mr. Majoros seems to be implying that in reviewing a rate case application, one should take into account the cost of gas when looking at that case. But the cost of gas is not what this case is about. As Mr. Fox stated in his testimony, this case is about the distribution portion of our rates, not the gas costs. Those are separate -- done separately through the purchased gas cost adjustment, which we file with this Commission each month under our rate purchased gas

cost rate tariff 88.

Then on page 5 of his testimony, Mr. Majoros states that a 5.7 percent expense growth rate is not reasonable for the period 2000, 2003. Again, this is a broad, general statement and it's not supported by the evidence. It's unsubstantiated and was made without looking to see why those costs went up. There are certain items that were identified in my direct testimony that increased significantly in 2002 from the 2001 levels. For example, the pension and post-retirement expenses both increased in the 10- to 15-percent range due to the market performance and lower interest rates. Insurance expense also increased significantly in 2002 and that was an event that has been experienced nationwide. There's no evidence to back up his statements and, thus, given the current cost levels, a 5.7 increase is entirely reasonable, it's explainable and it's supported by the evidence.

In fact, if anything, the 2003 levels are too low. Recently, we received the actuarial report for pension and post-retirement costs for 2003. The results show that the amounts we have in our projected 2003 case are significantly understated. And the reason that these pension costs are too low

is because of the returns experienced on the investment in 2001 and 2002. The updated expense for these items will result in an increase in our North Dakota gas operating expenses of $150,000 for pension and $90,000 for post-retirement expenses, above what we included in the case. This is a higher level. It's known. It will be -- start recording on the books effective January 2003 and should be recognized.

I might note that pension expense -- I talked about significant increases. It's a negative expense. It's a credit to expense. In other words, it lowers -- still lowers the cost of service because it is still a negative expense even with the increases we've seen.

In addition, the medical costs for 2003 have also increased from the levels projected. And we're projecting now for 2003 it will be $124,000 over the amount that was filed in our rate case.

That completes my rebuttal testimony.

MR. HOBERG: Any additional questions, Mr. Pearce?

MR. PEARCE: No. I have nothing else.

MR. HOBERG: Mr. Binek, any questions of Ms. Mulkern?

CROSS-EXAMINATION

BY MR. BINEK:

Q. A question that got passed on to you. What capital structure did the company use in its rate-of-return testimony in the electric case earlier this year?

A. I don't recall.

Q. On pages 1 and 2 of your rebuttal testimony -- I guess, let me go back to this other question. Would you accept, subject to check, that the capital structure that was used was based on a year-end 2000?

A. That may be, subject to check. However, this is an entirely different case. The electric --

Q. I realize that. That was just my question, what was used there.

MR. PEARCE: She's simply answering the question. I suggest we let her answer.

MR. HOBERG: Why don't you go ahead.

THE WITNESS: The electric rate case you are referring to is an entirely different situation. That was initiated by a staff complaint. It was not a general rate case filed by the company. I believe if you look at past rate cases filed by the company, going back as far as 1986, we have filed projected

test years and the Commission has used them.

Q. (MR. BINEK CONTINUING) On pages 1 and 2 of your rebuttal testimony, you object to the rate case cost recovery that Mr. Majoros has recommended. I believe you heard the testimony of Mr. Jeter that -- about the company preparing a new depreciation study that will be completed by the end of the year?

A. Yes, I heard that.

Q. If this study shows that MDU's depreciation rates should be changed, would the company be filing a new rate case?

A. I guess at this point I can't answer what we will or won't, whether or not we file a rate case.

Q. Okay. If the company did, this would result in two rate cases in the space of one year, wouldn't it?

A. Well, there are several options. As Mr. Jeter mentioned, one option would be a very limited scope, look purely at the depreciation study, and that would be different than a full-blown rate case like this where we are looking at many different issues.

Q. If MDU had completed the depreciation study in time for this case, we'd only have one case; is

that correct?

A. I guess I really can't answer that.

Q. On page 3 of your testimony you state your disagreement with Mr. Majoros' proposal to allow inflation increase and other expenses. Mr. Majoros says he declined to increase these costs for inflation because such inflation has not previously been allowed. Is he correct?

A. Last time this Commission reviewed it was in 1991 and at that time they did not approve it. However, I stated this is 2002. These rates go into 2003, and it is time to recognize that these costs are real and they do -- are subject to inflationary pressures.

Q. I'd like to have you turn to page 13 of Statement N.

MR. HOBERG: Page 13?

MR. BINEK: Yes.

Q. (MR. BINEK CONTINUING) Do you have that?

A. I have it here.

Q. Okay. Does that page show the principal categories of cost to which you have applied the inflation factor?

A. It shows the cost by function.

Q. What is the largest category of expense

shown on page 13?

A. Largest function is administrative and general expenses.

Q. What's the next largest?

A. Next largest is customer accounts.

Q. Okay. And this category of uncollectible accounts -- or that category would consist primarily of uncollectible accounts, wouldn't it?

A. That would be one of the factors in there. Not the sole factor.

Q. Why would uncollectible accounts increase with inflation?

COMMISSIONER WEFALD: Excuse me. What page are we on?

MR. HOBERG: Page 13 of Statement N.

COMMISSIONER WEFALD: Thank you.

THE WITNESS: Uncollectible accounts are a function of various things. I don't know that I can tie inflation to it specifically or tie it to inflation specifically.

Q. (MR. BINEK CONTINUING) Wouldn't uncollectible accounts be more correlated with the overall size of your revenue?

A. It would be revenue. It would also be the ability of customers to pay. Maybe if, you know,

the economy isn't doing well, customers might have more problems paying their bills. That could be indirectly associated with inflation. There are other factors other than the revenue.

Q. Does page 1 of Statement N show that you predict that overall revenue declined dramatically between 2001 and 2002 and will remain virtually flat between 2002 and 2003?

A. What we do in a rate case is, we tie our revenues and cost of gas together at a certain point in time in order to -- because we are looking, really, at what the distribution margin is. So the revenue number of 67 million -- this is in thousands, 944 for 2002 is not our projection of what actually revenue would be. It's our projection of what volumes will be for 2004 at the revenues at a certain point in time. In this case it was the revenues in effect for March of 2002. So this number is not representative of a calendar-year revenue that we would expect to see.

Q. Okay. And on page 13 of Statement N, is there any recognition that uncollectible accounts will change between 2001, 2002, corresponding with the decline in operating revenues between those two years?

A. We did not tie the uncollectible accounts to the revenue.

Q. At the bottom of page 4 and the top of page 5 you cite a number of items that you expect will increase, including pension and post-retirement expenses and medical costs. Has Mr. Majoros recommended disallowing your quantification of the 2003 amounts for any of those items?

A. Can you repeat the items he mentioned again?

Q. It was pension and post-retirement expenses and medical costs.

A. I believe he was in agreement with those.

Q. Now, I'd like to have you turn to page 2 of your rebuttal testimony, specifically line 4, and please read -- on page 2, line 4, would you read the statement there down to the end of line 10?

MR. HOBERG: It's part of the record. Can we save time by asking a question about it?

MR. BINEK: No. We'd like to have that read because there will be some followup questions.

MR. HOBERG: Does she have to read it out loud?

MR. BINEK: I would prefer that.

MR. HOBERG: Okay. Ms. Mulkern.

THE WITNESS: The part starting with Montana-Dakota?

Q. (MR. BINEK CONTINUING) Yes.

A. Montana-Dakota was able to refrain from filing for a rate increase during that time because it took action to increase efficiency and reduce costs using new technologies where possible, rather than seeking an increase in rates, all addressed by Mr. Fox in his direct testimony. Montana-Dakota will continue to strive for operating efficiencies and cost reductions, but it is not anticipated that it can replicate past performance and refrain from filing for another five years.

Q. Is it a fact that you did not project past efficiencies and cost reductions in your 2003 test year costs?

A. All past efficiencies were included in the 2001 base period and, therefore, were included in our 2002 and 2003 projected test periods.

Q. Where do we find that?

A. Well, these efficiency measures have taken place over time, over a period of years. And what's happened is Mr. Fox mentioned that we're serving more customers per employee and that's taken place over time. Basically, our employees have remained

flat. I think maybe even declining. So what you see in 2001 is the effect of all of that. So that's implicit. In our base period those things are -- had already happened.

Q. Do we see further declines in 2002 and 2003?

A. No. Because, as Mr. Fox mentioned, and I think I mentioned, we will continue to strive, you know, continue to look everywhere we can to be more cost efficient and reduce costs, but we've looked at all those opportunities. Right now, while we'll continue to look, our option is to file for a rate increase, which is why we are here.

Q. Now, turning to page 3 and lines 7 to 9, is it true that the Commission should not rely on its 11-year-old decisions?

A. I think what I'm saying there is that 11 years ago was the last time they looked at it and it's time to take a look at it again because things have changed over 11 years. I think our point is that these costs are real costs. This isn't a game we're playing with these costs. They exist, and they are subject to inflationary pressures. So we do believe the Commission should look at it again and realize it is time to acknowledge that and

include an inflation adjustment in our cost of services.

Q. Should the Commission rely on the Company's study and data that are 11 years old?

A. It depends what you're looking at. As regards the inflation adjustment, I would say no, because I can't make a blanket statement that any time period is exactly the same for everything.

MR. BINEK: No further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Wefald, any questions of Ms. Mulkern?

COMMISSIONER WEFALD: Yes.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. What if the Commission were to pick a different number than 2.81 percent, higher or lower, how would the company react to that?

A. I think we would want to see some recognition of inflationary pressures, and if the Commission would choose a different realistic number, we would accept that.

Q. How would you define "realistic number"?

A. Well, I guess we defined it as a three-year average of the inflation adjustment. If the Commission might pick a slightly different period, a

two-year instead of a three-year average or some other measure that -- you know, that would acknowledge it, we would be content with that.

Q. I suppose you can't speculate on what the Commission's thoughts were in not giving an inflation adjustment, but I can perhaps speculate that they wanted to give an incentive to the company to practice savings and to find ways to have savings in those costs while moving forward with their business.

If the Commission chose to give a less than 2.81 percent with that same idea of giving incentive to the company to try to achieve savings in those areas, what would you think of that?

A. Well, I think the company -- we've looked for efficiencies. Our incentive is to -- one of our incentives is to not come in and file for a rate increase, so we are constantly looking for efficiencies so as not to let our costs go up to our customers. If the Commission -- you know, as you said, I can't speculate on why the Commission in 1991, precisely why they did not accept it, but I think we already have the incentive to reduce our costs right now.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark, any questions?

COMMISSIONER CLARK: I do have just a few.

EXAMINATION

BY COMMISSIONER CLARK:

Q. Some of them are related again to that depreciation study. I know Mr. Keller deferred a couple questions to you. And the reason I keep coming back to this is because I do have some significant concerns in that this is a rate case being brought by MDU and this has become a huge portion of the rate case. But it's like we're arguing about something that could be moot in just a very short amount of time. And I want to point out the scenarios that could happen here.

But are you familiar with when the contract was signed and when this depreciation study was supposed to be done? Is it a date that was originally supposed to be done for this rate case, or was it kind of always anticipated that it would be done shortly after when you entered into the contract with the consulting firm?

A. First of all, I'll say I'm generally aware of the time frame for this. And, initially -- and I think Mr. Keller explained it very well. It was

difficult to find a consultant. We did hire a consultant and that person had to complete a depreciation study for Great Plains before they could start working on Montana-Dakota's study and that took more time than anticipated.

Our intent was to have a depreciation study, I believe, around October 1st. Because of various factors, we weren't able to have one by October 1st.

Q. Well, if it were to be done by October 1st, that wouldn't leave a whole lot of time for the staff depreciation expert to delve into it, would it?

A. No. I'm just kind of referring to the general time frame of this depreciation study.

Q. When, about, did you learn that it wouldn't be done on the October 1st time frame?

A. I guess I really can't recall when I heard. I said I'm generally aware, but I wasn't specifically involved in the contract.

Q. Are you aware of the other pending cases that you have in your other jurisdictions, will that study be able to be used in those jurisdictions?

A. We have filed so far two other rate cases in generally about the same time. There was a study

filed -- or not a study. A rate case filed in Montana that there will not be a depreciation study by the time that the Commission holds the hearing. We also filed a rate case in Wyoming. They have until June of 2003 to make a decision. I don't know yet what the status would be of the depreciation study in that case.

Q. And you haven't filed in South Dakota yet?

A. We have not yet filed in South Dakota.

Q. Do Montana or Wyoming require periodic depreciation studies to be filed like some states do on a semi-annual basis?

A. None of the four states that Montana-Dakota serves natural gas or electricity in requires a depreciation study.

Q. Was there any consideration during -- that you're aware of during the last few months that MDU considered delaying this rate case until the Commission could consider it as a whole as opposed to potentially having to do a couple of different rate cases?

A. Could you repeat that?

Q. Are you aware of any discussions at MDU -- have you considered at all kind of holding off on this once you became aware that you may not have a

large portion of your -- the evidence that you should have for a rate case available?

A. Well, we filed this rate case in April of this year. There are no statutory or legal requirements to file a depreciation study. So our filing is in compliance, if I understand, with the legal and statutory requirements. So I don't think that we were remiss in filing a rate case without a depreciation study because it is not required. I think you had another part to that question.

Q. Well, maybe just following up on that, I guess I wasn't implying that there was any legal requirement. It's just my own thought is that, potentially, MDU, being that this is their case and the burden of proof is on them, would want the best information available, but maybe -- I'm just going to close up here quick.

You had mentioned that there may be a number of scenarios that could happen as this plays out. Let's assume that the Commission decides a number of issues that are outside of the depreciation part of this case. I think that has to be done in about a month or so. Is that in November, I think? I can't remember what the exact time frame is that we have to have our decision out.

But -- and then do what MDU is suggesting, which is just kind of put aside the depreciation portion of this.

How does that then play out on December 31st beginning next year when you have a new depreciation study? What are the scenarios that could happen here?

A. Well, I think part of that is maybe off a little bit. Everyone seems to be presuming in this case that there will be -- that, one, the depreciation rates are going to go down when we do a depreciation study. And I don't think that's a presumption that we can make now. We've provided in this case a 1991 study, a fully detailed study, and we still at this point still stand on that study. We believe that it's still a good study and that is what we filed our case on and it's a good, detailed study based on many years, details going back many years, a lot of data, a very complete study.

Q. Okay. So let's go through the scenarios again. If it's the same and it shows the same as the 1991 study and if we accept that as part of this rate case, then nothing would change. If the depreciation changes so that it becomes, in effect, a rate decrease, then do you file updated tariffs

just decreasing their rates, decreasing the tariff rates?

A. I think I'm getting into an area that I think might be, as far as a legal area, as far as what the Commission -- you know, as far as issuing an order and after that. So I think that's really a legal issue and I don't feel that I can properly address that.

Q. Okay. But MDU could consider filing another rate increase if the depreciation schedules indicated that was appropriate, right?

A. Yes.

COMMISSIONER CLARK: Okay. That's all I've got then.

MR. HOBERG: Thank you, Commissioner Clark. Mr. Diller?

EXAMINATION

BY MR. DILLER:

Q. Ms. Mulkern, isn't it true that adjustments for inflation cause inflation? That's a question that Mr. Myer Shark used to ask all the time and I felt like we needed to get his name in the record.

And so isn't it true that -- would you agree that adjustments for inflation causes inflation?

A. I would not agree with that statement.

Q. Could you explain that, please? That's all right. I withdraw the question. I just wanted to have some fun. Let's see if I have a real question here.

I think based on the exchange I heard between you and Mr. Binek, if I could maybe characterize your response to him as there's not been any correlation between CPI and these other O&M expenses that haven't been inflated individually in the past, but you feel like CPI will be a fair indicator of what you can expect with these other O&M costs in the future; would that be a fair characterization?

A. I think that CPI recognizes that these costs are going to increase with time, with inflation.

Q. Now, have you done any long-term comparison between CPI and these other O&M expenses that are being talked about here, any long-term correlations to -- you know, I mean, certainly some years it will be because of efficiencies and this and that the company beats the inflation indicator, but have you done any long-term comparison to see if there's any long-term correlation between CPI and these other

O&M expenses?

A. Well, I'm not sure what constitutes long term, but I did look back to 1994, since the last rate case, at all these other items, and the increase is greater than inflation for the same time period.

Q. Greater than the CPI?

A. Yes.

Q. That's surprising. But we don't have any -- that's not on the record anywhere?

A. No. That was just something that I did on my own.

Q. Is that something that's available for providing to the Commission, or is that just something that you kind of did ad hoc and didn't really --

A. I have a workpaper on that.

Q. Would you mind providing that as a late-filed exhibit?

A. I can provide it.

Q. I mean, it's not really that long term, but it might be interesting to look at.

MR. HOBERG: That would be Late-Filed 5, Mr. Pearce.

MR. PEARCE: Yes.

MR. DILLER: That's all the questions I have.

MR. HOBERG: Thank you, Mr. Diller. Any further questions of Ms. Mulkern?

COMMISSIONER WEFALD: I might have one here. Just a minute.

FURTHER EXAMINATION

BY COMMISSIONER WEFALD:

Q. Go through with me again what expenses are covered under these other expenses where you have this list of them. Which exhibit is that?

A. Well, the one on the exhibit is Statement N, page 14.

Q. Page?

A. Statement N in the statement book. I think it's Exhibit 2.

MR. HOBERG: It's a big book, Statements A through O.

Q. (COMMISSIONER WEFALD CONTINUING) Yep. Statement N?

A. Page 14.

Q. Statement N, page -- like in no?

A. Like no.

Q. Page 14 of 23?

A. Yes.

Q. All right. So I'm seeing on this just cost of gas?

A. These are the items that we did adjust individually. These are the items that make up 71 percent of total operating maintenance expense.

Q. All right. What are the ones that are not?

A. The ones that are not are the ones in the last column that are left over after you adjust all the others separately and that's the one -- that contains such items as postage expense.

Q. Now, are you looking under all other O&M?

A. That's the one.

Q. But it doesn't have anything broken out as to what those include, so you are going to give me a list right now?

A. There are many items in this list. These are the ones that make up the 29 percent -- those five items make up 71 percent of all of the O&M, operating and maintenance expenses. All other items make up 29 percent.

Q. How do we know which ones are administrative and general of four-million-ninety and there's a separate list of ones that aren't covered? There's some under administrative and general that are covered and then there's some that

are not, $1,617,000?

A. Right. We started with our operating expenses in total for North Dakota gas by what we call function, distribution, customer accounting. And from that we deducted in the same by function, the labor expense.

Q. Do you determine which ones are not covered by this or did the Commission in its last case?

A. No. We looked at what -- kind of the major cost items, the ones that make up the majority of the costs. Five items make up 71 percent. So we looked at those five items specifically. Or I should say some we looked at for other reasons, like rate case expense, but we looked at those five items individually and adjusted those individually.

Q. I'm not following you at all. Are they -- rate case expense has --

A. Rate case expense is included in the administrative and general costs area and --

Q. One underneath that?

A. One. And that one we adjusted individually because we were looking at the cost of this rate case proceeding, rate case expense. So since we were adjusting that separately, we took it out.

Q. You've had other gas cases during this

time. I don't understand this chart. So maybe I should just visit with my staff, but I just don't understand the chart at all.

A. If I can explain, if you want me to answer.

Q. Keep going.

A. If you look in the left-hand column and it says "per books," those were the operation and maintenance expenses for 2001.

Q. All right.

A. And it shows it by function. For instance, the distribution, it covers all the costs in operating and maintaining the distribution system. Customer accounting is for all the billing related and, you know, accounting for the customer for that, and so on.

Q. The first one is a total of the other columns; is that correct?

A. No. The first column is a starting point.

Q. All right.

A. From there we were going to -- for instance, for costs of gas for projected 2000 and 2003 we calculated that so we adjusted it individually so we deducted it from the total because we're doing that someplace else, we don't want it in this adjustment. Next, we looked at

labor and, again, we're going to adjust that separately, so we're going to deduct all the labor costs from this total per books amount. And labor goes into all the functions also.

We went down, continued with benefits, which is all charged to an administrative and general account because we adjusted the items and benefits separately. And then insurance we looked at separately. And rate case expense and advertising. So we started with the total per books, we adjusted everything we were going to look at separately, and what's left over is that 29 percent I referred to and this is what we applied inflation to, these costs that were remaining after we adjusted certain items individually.

Q. So the cost of gas is $76,000. Is that one of them then?

A. That was -- yeah. That's what we had in 2001 for gas costs.

Q. $7,988 of labor, is that another one, or am I wrong?

A. No. That was labor expense for 2001.

Q. I don't get the chart, but I'll work on it later. Thank you. I don't understand it. But thank you very much for trying.

MR. HOBERG: Any further questions of Ms. Mulkern? Thank you, Ms. Mulkern. You have three witnesses left?

MR. PEARCE: Yes.

MR. HOBERG: And a short time to do them in. Next one is Ms. Aberle.

MR. PEARCE: Call Tamie Aberle. And I have one -- I have a one-page exhibit.

(Exhibit 37 was marked for identification.)

MR. HOBERG: Ms. Aberle, you also testified yesterday. I just need to remind you, you are still considered to be under oath. Mr. Pearce. Her rebuttal is Exhibit --

MR. PEARCE: 26.

MR. HOBERG: -- 26-52.

TAMIE A. ABERLE,

having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Ms. Aberle, you prepared for this case, did you not, a prefiled written rebuttal testimony?

A. Yes, I did.

MR. PEARCE: And that's been marked Exhibit 26. I'll offer that.

Q. (MR. PEARCE CONTINUING) And ask you to summarize your testimony briefly.

MR. HOBERG: Any objection to 26?

MR. BINEK: No.

MR. HOBERG: 26 is admitted.

MR. BINEK: Has this been marked as an exhibit?

MR. PEARCE: It's marked 37.

MR. HOBERG: He hasn't offered it yet.

THE WITNESS: I will begin with why I do not agree with Mr. King's position regarding the allocation of mains and the class costs of service study. The company has proposed an allocation of mains based on a customer and demand component. Mr. King advocates that it is not correct to allocate a portion of mains on the customer component. We believe it is appropriate to do so and it is a practice that is used in the gas industry and is supported in a report prepared by the NARUC staff subcommittee on gas. And I've included some references in my rebuttal testimony, Exhibit 26. We did prepare a study that indicates that approximately 36 percent of the mains investment should be allocated to the customer component.

Also, Mr. King suggests in his testimony that main additions are only made at the very edges of the system to provide service to new developments. In our system, main additions are also required for purposes of enhancing system integrity and maintaining pressure requirements throughout the system as customers are added. Main additions -- main investment is not a variable cost that increases or decreases as more or less gas is used. Also, the concept of value of service is not appropriate for allocating embedded costs as Mr. King advocates. The value of the heating content of gas does not represent the company's embodied costs or the causation of that cost.

Secondly, with regard to the allocation of mains, the allocator used by Mr. King includes total throughput for the energy, which results in excessive amounts of mains being allocated to the interruptible customers who are not utilizing the distribution mains in order to receive natural gas service. We have a number of customers that are connected directly to the transmission system and there are no mains associated with serving those customers.

I have prepared a study reflecting 50

percent allocation based on throughput at distribution level and 50 percent at the peak day used for the firm customers, and those returns are reported in my testimony. The results are that -- results in higher returns for the Air Force and the interruptible classes, which are those classes that have a larger percentage of customers connected directly to the transmission system.

I also do not agree with Mr. King's allocation of the rate increase, based on either the company's class cost to service study or a class study based on Mr. King's proposed allocation as modified and as set forth in my Exhibit TAA-4. An increase to the Air Force small interruptible or large interruptible class is not warranted. The subsidization provided by the interruptible classes should not be increased by allocating another increase to those customer classes that are already providing a return on rate base higher than the overall return. The increase -- any increase in revenues to this class is also at risk given the flexible rate provision applicable to the interruptible customers. Presently, approximately 20 percent of the small interruptible class and 80 percent of the large interruptible volumes are

transported under discounted rates.

Finally, the Commission did authorize allocating the entire increase to the firm customers in the last rate case.

Now, I'd like to address customer impact discussed by Mr. King yesterday in his testimony. I think it's best to focus on the dollar value impact, rather than the percentage increases. And, also, the rate proposal must be looked at in its entirety to talk about customer impact. I'd like you to take a look at the exhibit that was just handed out marked as Exhibit 37, or TAA-6. This is the same exhibit that is in my direct testimony as Exhibit TAA-2. I've simply added two lines that I think help to portray better what the impact of the rate proposal has on the residential customers.

COMMISSIONER WEFALD: This is TAA --

THE WITNESS: Dash 6. The one that was just handed out --

MR. HOBERG: It's a single sheet.

THE WITNESS: -- to you as a single sheet. This is a representation of a customer's bill under current rates and under the proposed rates as filed. And this is a typical, average residential customer using 110 decatherms. And it is meant to represent

how that gas is used throughout the year. If you look at the line that I've added, base rate as percentage of total, it's indicating that under the proposed rates, our basic service charge or our fixed component of our rate would collect about 28 percent of the total customer's bill versus 16 percent under the present rate. So as shown there, it's not in the high percentages I believe were discussed yesterday.

Also, corresponding with the increase in the basic delivery charge is a decrease in the distribution delivery charge or the commodity, the variable part of the rate. And I've shown on that second line that the non-gas commodity portion of this customer's bill would decrease by $37 under this example or approximately 44 percent.

A couple of other items I'd also like to point out. The increase to the customers, as we've noted to a residential average customer would be approximately $24. As shown in the amount of increase column, the highest increase would be in the summer ones when they are using less gas, but that increase would only be $4 in those months.

And as shown in my rebuttal testimony, Exhibit TAA-5, there's another bill comparison,

which just shows varying levels of consumption, because, as we know, there's customers above and below this. As shown in that Exhibit TAA-5, if a customer used zero volumes through the entire year, their increase per month would still be only $5.20.

MR. HOBERG: That's the last page of your --

THE WITNESS: Last page of my prefiled testimony, rebuttal testimony.

This rate form also provides customers -- or still provides customers with an incentive to conserve natural gas because each decatherm of gas that they conserve, there's still a reduction of $3.33 associated with that less gas use. And that is the combination of the distribution delivery charge and the cost of gas. So they're showing that still the majority of the customer's bill is still a variable component.

What the proposed price structure will do is provide relief to customers during the winter months when their heating requirements result in higher gas use by lowering the amount collected on the volumetric basis and sending an accurate price signal by accurately reflecting fixed costs in the fixed cost component.

Just a couple comments with regard to the distribution delivery stabilization charge that was presented in -- by direct testimony. The company has proposed to implement such a mechanism if the proposed base rate levels are not approved. And I also just wanted to comment that the deferral-type mechanism will not result in significant impact as suggested by Mr. King. As shown on Exhibit No. 8 in Mr. Feingold's testimony, based on -- where we did an example based on historic results, the amount charged per bill will be minimal and significantly less than most PCA changes. In that example, over the four-year period reviewed, a residential customer would see a monthly bill change ranging from a negative 20 cents to a positive 84 cents. And that was a bill change, not an amount per decatherm.

And, finally, I wanted to just comment on the company's proposal to build a basic service change on a daily basis versus a monthly charge as done today. And the only reason for proposing this change was to provide better information to those customers that are cutting in and out of service and are receiving bills for less than a normal billing period. The proposal will not affect our meter

reading or billing schedules.

That's all I have for my summary.

MR. HOBERG: Are you offering Exhibit 37?

MR. PEARCE: I'm offering Exhibit 37. I have no other questions.

MR. BINEK: No objection.

MR. HOBERG: Okay. Exhibit 37 is admitted. Thank you, Mr. Pearce. Mr. Binek, do you have any questions of Ms. Aberle?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. King has proposed increases in customer charges, hasn't he?

A. Yes, he has.

Q. Specifically, he proposes that even if rates are decreased, the volumetric rates should be flattened and the initial block revenue be recovered through increases in the customer charges; is that correct?

A. Yes.

Q. Do you agree with that recommendation?

A. Yes. At a minimum I believe that should be done.

Q. Mr. King also recommended that if rates are

increased, the increase in customer charge should be twice that of the volumetric rate.

Do you agree with that?

A. I agree if the proposal is -- the rate increase is approved as provided, that our base rates would be approved.

Q. Okay. Well, it isn't nearly as much of a customer charge increase as you propose. Would you agree that Mr. King's proposal moves in the direction of the rate design changes the company is seeking in this case?

A. I would agree that it moves in the direction.

Q. Are the proposed movements toward the company's preferred rate design sufficient to permit the company to withdraw its DDSM proposal?

A. I could not answer that at this time.

MR. BINEK: I have no further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Wefald, please.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. Yes. I'd like to ask a few more questions about this monthly charge divided into a daily charge. Tell me about the people. You say these in

and out accounts. I would like to have a little information about that on the record.

A. The accounts we're talking about are people -- you know, in the fall college students. We get a lot of people in and out. They may move in in the middle of the month versus the beginning of the month.

Q. So what happens at this point --

A. If you are less -- excuse me.

Q. -- if I would move in on the 15th?

A. We have a normal billing cycle, which is 28 to 32 days. If you're outside of that normal billing cycle, your bill is prorated. So that if you're only in service today for -- in service under today's rates for 10 days, you'll receive 10/30ths of the customer charge on your bill. But that bill -- the way that is presented on the bill, because of the way -- it's a proration. Our customer charge is a monthly charge. So it's a combined number on the bill. It shows -- it's combined with the amount of customer charge and usage at that premise for that time period.

And the daily charge would simply allow customers to see the number of days in the bill cycle, which is presented on the bill today, and

multiply that by the charge that's in effect, the daily charge that's on the tariff sheet, if approved, and be able to calculate that amount. It's simply an informational item. The real crux of our proposal is the amount of the increase and not so much whether it's billed or presented on a daily basis versus the current monthly charge. It really will not impact the revenues we collect or the amount customers pay. It's really an informational item.

Q. I understand that. So if you're giving these people who only are using service less than a month and they are already receiving a different amount than the total amount on their bill, then we can just figure that those people are taken care of already?

A. Mm-hmm.

Q. So --

A. It's just information for those people.

Q. So don't you think -- well, so you don't really care whether or not -- you're telling the Commission you don't really care whether we do this on a daily basis or on a monthly basis, as long as the costs come out the same for customers throughout the year?

A. I would rather have the increase on the base, the fixed charge, the monthly amount. And the other was just a move toward trying to provide more information.

COMMISSIONER WEFALD: Thank you.

MR. HOBERG: Thank you, Commissioner Wefald. Commissioner Clark.

COMMISSIONER CLARK: I have no questions.

MR. HOBERG: Thank you. Any further questions of Ms. Aberle? No questions. Thank you, Ms. Aberle.

I think perhaps we should just take -- for the court reporter's benefit take a short break right here. A strict five minutes.

(Recess was taken.)

MR. HOBERG: We are back from a short recess. Your next witness, Mr. Pearce.

MR. PEARCE: I call Mr. Spratt.

MR. HOBERG: Mr. Spratt, I don't think you've been sworn in.

THE WITNESS: No, I haven't.

MR. HOBERG: Were you here earlier when I gave the admonition in regard to perjury today?

THE WITNESS: Yes, I was.

MR. HOBERG: Being advised of the penalty

for perjury, do you promise to tell the truth in that matter being heard? If so, answer I do.

THE WITNESS: I do.

MR. HOBERG: Thank you. Mr. Pearce.

RICHARD D. SPRATT,

being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Spratt, you have prepared written rebuttal testimony that's been filed in this case, have you not?

A. Yes, I have.

Q. I'll ask you to just briefly state your name and business address and what your position is with the company, and then if you could summarize the important points in your written rebuttal testimony.

A. Okay. It's Richard D. Spratt. My business address is 400 North Fourth Street, Bismarck 58501. I'm vice-president of human resources for Montana-Dakota Utilities, which is a division of Montana-Dakota Resources Group, Inc. My responsibilities include benefits and compensation, staffing, organizational development, behavior, labor and

employee relations.

Q. Thank you. Would you summarize your written testimony then?

A. Yes, I will. And I basically would like to make just a couple points. I'm here basically to refute Mr. Majoros' -- am I saying that right? -- his sort of unsubstantiated statement that we should eliminate bonuses and hold 2003 labor costs equal to 2002.

Let me start with the bonuses. Basically, we have bonuses as part of a total compensation program, which includes not only bonuses, but it also includes your base salary and your benefits and a certain portion of that salary is what we call at-risk. And we do that in varying degrees with different employees based on what's competitive. And that's my first point is that, you know, we see this to use in a competitive way. It makes us competitive and attracts and retains employees for us and so that's, A, why we have a bonus. Now, B, another reason why we do is it sort of focuses employees in on those areas that we need them to focus in on, particularly in recessionary times, to try to save costs and/or at least reduce costs and have it more efficient. So that's my first one,

bonuses.

Second one, compensation, where he says that we basically should hold the 2003 labor costs equal to 2002 level. A couple of things there. First of all, again, we use as part of a total compensation package a base is a portion of that total compensation package and to be competitive and to attract and retain employees, we need to have competitive wages and salaries. And right now -- along with that, we do what we call a compa-ratio analysis to see just how competitive we are. We also use about 11 different surveys that will show us degrees of competitiveness in various areas, including our engineering and our IT staff and our administrative staff. And the compa-ratio analysis that we've done shows that we're really behind competitively, not only in our industry but in general industry in terms of what we've done. So I think in -- to go back a little bit, in 1996 when we started on this -- really started tightening down and started trying cost efficiencies and, you know, looking at costs and one of the things that we did is we started holding our labor costs down quite a bit. And we've gotten behind over the years because of that.

To say that we should not increase or we shouldn't grant, I guess, an increase in labor costs is tantamount to making us fall back another probably -- in one case, in the executive case it would be somewhere in the neighborhood of going from 11 to 15 percent behind. And then in the office and administrative it would be about 9 percent behind. So in those two areas, you know, I think we need to -- it's our belief we need to continue to do what we're doing primarily to get the efficiencies.

Another way we can do this, though, is we could -- particularly with bonuses, is we could build that into our base structure, which basically would cost more money then and that wouldn't be very good for our customers because that has to be passed along as well.

The last thing I'll say is that it's my understanding that the Commission ordered Case No. PU-399-01-186 has allowed these kind of costs and expenses before. With that, questions?

Q. (MR. PEARCE CONTINUING) Just one question, Mr. Spratt, to clarify. Why would it cost more to package all of the compensation into wages or salary rather than bonuses?

A. Right now we have a certain -- in the

beginning I said we had a certain portion of our salaries that are at risk and that -- it's dependent on how we perform against financial goals, as well as -- excuse me -- goals that are personal goals that are set up, cost goals, usually. And that's to make us perform better and to be more efficient. But if we just took those and that's at risk, and if we don't -- if we don't achieve those goals, then we don't get paid that portion of it. So if we just rolled it in, that would obviously make the cost of our payroll go up.

MR. PEARCE: Okay. I'll offer Exhibit 27. I have no other questions.

MR. BINEK: No objection.

MR. HOBERG: Exhibit 27-56 is admitted.

COMMISSIONER WEFALD: Where is 27?

MR. HOBERG: 27 is the rebuttal testimony of Richard D. Spratt. Mr. Binek, do you have any questions of Mr. Spratt?

MR. BINEK: Yes.

CROSS-EXAMINATION

BY MR. BINEK:

Q. Mr. Spratt, what was the total amount of bonuses and commissions awarded last year?

A. Dollar?

Q. Yes.

A. I don't know.

Q. Would you accept $518,000 as the amount, subject to check?

A. I honestly don't know.

Q. Okay. Do you know how much of the -- of the amount was commissions and how much was bonuses? I assume since you don't know the amount, you probably don't know that, either.

A. No.

Q. Would you be able to tell us what the percentage split would be between commissions and bonuses?

A. No. In fact, that commission kind of throws me. I'm not sure -- I know I saw it in here. I think when we're talking about commission, we're talking about incentive and bonuses, period. We don't really have anybody on commission, that I'm aware of. So this would be, in fact, 100 percent bonus.

Q. Okay. And then on page 4 you state 60 percent of hourly employees, 75 percent of salary employees and 90 percent of management employees are eligible to receive bonus. What determines these percentages?

A. Well, those were done -- those are basically surveys that we've done, that we're a part of and that shows that these are the percentage splits that are partaking in bonuses.

Q. Surveys taken of whom?

A. Various companies, including our own, the utility industry.

Q. But these percentages apply to MDU, not to other companies, right?

A. No. No. These percentages apply to other companies. If you took the total of the companies in our surveys, if you go back to -- refer back to in my testimony the back page there, you can see if you go down to utility and energy section and you just take the 20 -- on the left-hand side you'll have industry sectors, utility and energy. What they're showing there is in the utility and energy sector -- well, it shows all -- a number of sectors, but particularly in the utility and energy sector, they're saying that there's an average. If you're in the 30 to $39,000 range, there's a 62.7 percent of those companies are offering bonuses. For 40,000 or more it's 75 percent.

MR. HOBERG: Just for the record, you're at RDS-1, page 1 of 3, on the back?

THE WITNESS: Yes. There's no page number on it.

MR. HOBERG: It's up at the top, RDS-1, page 1 of 3, right-hand corner.

THE WITNESS: Oh, yes. Yes, that's it. That's RDS-1. And then RDS-2, if you go over, they'll show that the utility and energy sector and it gives a number of responses up at the top and the sample was 1,149 companies, of which 76 were utility and energy and 91.2 percent of those offered. So these numbers are industry numbers. They're not our numbers. Our numbers are a little different.

Q. (MR. BINEK CONTINUING) Okay. So what percentage of hourly employees at MDU receive those bonuses, commissions, whatever they are?

A. 100 percent.

Q. Okay. And salary employees?

A. As well, 100 percent.

Q. And management employees?

A. 100 percent.

Q. So all employees are eligible to receive?

A. All employees are eligible, correct.

Q. Within each category that's eligible to receive bonuses, what proportion typically receives them in each year?

A. I'm not sure. I can tell you approximate percentage, but I'm not sure how many.

Q. Give us the approximate percentage.

A. Well, to give you an example, two years ago 75 percent of -- 75 percent of our total employee population eligible for the BETA received a 7 percent bonus. And then last year it was about -- overall it was about six-tenths of a percent that they received.

Q. Okay. Again, 75 percent of the -- is it 75 percent of all employees --

A. Yes.

Q. -- received these bonuses?

A. That's correct.

Q. And it was 7 percent, and what was the figure last year?

A. Last year was six-tenths of 1 percent.

Q. Okay. Does the total amount of bonuses awarded each year typically remain the same, or does it vary from year to year?

A. The number of bonuses?

Q. Total amount of bonuses.

A. The total amount. It would vary some year to year, depending on how we did against our financial goals and how we did against our personal

goals.

Q. Does the total amount of bonuses vary among the three categories of employees, the hourly, salaried and management?

A. Yes, it would.

Q. Do the same employees typically receive bonuses each year?

A. Overall I would say, yes. I mean, 100 percent of our employees are eligible for bonuses and so, I mean, there are some that will -- particularly, if we meet our financial goals, everybody shares in that one, but if they don't hit their personal goals, they wouldn't share in that portion of it.

Q. At the top of page 7 you state that the annual wage increases each year have averaged 3.7 percent over the last five years. According to our calculation, that would mean that over the total five-year period MDU has increased wages by 20 percent. Would you agree?

A. Yes, approximately.

Q. Have bonuses increased proportionately?

A. No. Bonuses have been up and down. I mean, one year -- like I said, last year it was very low. The year before that it was fairly high.

Q. During the past five years has MDU received any increase in its gas rates?

A. I'm not aware of that.

Q. In fact, in 1998 the company agreed to a gas reduction; isn't that true?

A. I don't know. I've only been here for about a year and a half.

Q. So you wouldn't know when the last gas rate increase was?

A. That's right.

Q. Okay. Would you accept, subject to check, that the last case was decided on November 23, 1993?

A. Would I accept that?

Q. Yes.

A. Certainly, yes.

Q. Has the company increased wages each year since 1993?

A. No, I don't think they have. Actually, we had a freeze, I know, for a while and, again, that's -- I'd have to defer that. We had a freeze on wages there for a while, I know.

Q. But over the last five years you did agree that the increases have averaged 3.7 percent each year?

A. Yes.

Q. Okay. How has the company been able to hold retail rates level and, in fact, reduce them while increasing wages each year?

A. Part of that, I think, goes to the fact that we've just become much more efficient. If you look at our population, we've decreased over the years. And, you know, we've asked our employees actually to do more and then technology has also helped us out in that respect.

Q. In other words, you've been able to improve labor productivity over these past years sufficient each year to offset the annual increases in wages, salaries and bonuses; is that correct?

A. I don't know if it completely offsets it, but, yes, essentially, you're correct. We've increased our labor productivity.

Q. Where in this case do we see a forecast of the productivity offset to the wage and salary increases you predict for the year 2003?

A. Where?

Q. Yes.

A. Say that again, please.

Q. Where in this case is there a forecast of a productivity offset to the wage and salary increases you predict for the year 2003?

A. There isn't one per se. We have goals and objectives, however, that -- in fact, we're formulating those right now -- that will hopefully get us some of that offset.

MR. BINEK: Thank you. I have no further questions.

MR. HOBERG: Thank you, Mr. Binek. Commissioner Wefald, do you have any questions of Mr. Spratt?

COMMISSIONER WEFALD: Yes.

EXAMINATION

BY COMMISSIONER WEFALD:

Q. Where is the data on labor costs and bonuses in this case?

A. Where's the data?

Q. Mm-hmm.

A. I'm not sure. We can get that data, if you need it.

MR. HOBERG: Mr. Pearce?

MR. PEARCE: I imagine it's in the statements.

MR. HOBERG: Statements A through O?

MR. PEARCE: Somewhere in there. I think Ms. Mulkern testified to it and that would identify which of the statements or schedules it's in.

THE WITNESS: Are you talking about the numbers themselves?

Q. (COMMISSIONER WEFALD CONTINUING) Yes. For 2000, 2001, 2002, 2003.

A. Okay.

Q. Where would I find the breakout of the numbers of labor and bonuses in this case?

MR. PEARCE: Perhaps we can have Ms. Mulkern point us to that. Perhaps we can find it here. It's certainly in these statements of the expense items. I'll see if we can find it. It's just been pointed out to me from both sides. In Statement N, page 7 of 23 and --

COMMISSIONER WEFALD: Statement N, page 7 of 23.

MR. PEARCE: I don't know if the witness has the exhibit up there. I'll give him this copy.

Q. (COMMISSIONER WEFALD CONTINUING) So am I correct then that the labor expense in 2001 includes bonuses as well? Bonuses as well as other labor expense?

A. Reflects average -- yes, 3.15 increase reflecting average 2002 bonus. Footnote 1 there.

Q. Well, it doesn't tell me the exact amount that was paid out in bonuses during that time, does

it?

A. 3.15 percent, but it doesn't give you the dollar number, you're correct.

Q. But it says that that reflects an average 2000, 2002 bonus?

A. Yes. What was your question?

Q. My question was, does this chart tell me how much was paid in labor and how much was paid in bonuses in the year 2001?

A. Year 2001, it does not, it appears. I'm sorry. No, it does. It's 2001, 2002, but it just gives you the average of the increase. It doesn't break out bonus and dollar.

MR. PEARCE: I think if I may interject, it's -- labor expense isn't broken out, I don't think, anywhere in those statements. That would have to be extracted from the company records. I guess it could be done.

MR. HOBERG: Is that something you'd like to see?

COMMISSIONER WEFALD: Well, I think it would be helpful because the company -- the staff is arguing that we should eliminate bonuses and they have a number. They're saying that it's half of the increase or something that's projected -- I saw that

number someplace. Just a moment. In Mr. Majoros', on page 15 it says, it is unreasonable to be granting bonuses which, in fact, amount to roughly half of the company's overall requested increase when the company is proposing a rate increase to begin with. So I'd like to know what those numbers are so that I can understand better when he talks about it's roughly half of the company's overall requested increase. I'm assuming in labor costs.

MR. HOBERG: Mr. Pearce, can you provide that?

MR. PEARCE: I assume we can. We'll certainly try to provide that number. That would be 6, I think.

MR. HOBERG: Late-Filed Exhibit 6.

Q. (COMMISSIONER WEFALD CONTINUING) So perhaps it would be helpful to have the actual numbers for 2000 and 2001. We don't -- do you know what the numbers are yet for 2002, because we are not at the time end of the year?

A. No, we don't know that now. We wouldn't have the actual until after --

MR. HOBERG: Could you project those out, though, on --

THE WITNESS: We could, yes. It's not

looking good for this year.

Q. (COMMISSIONER WEFALD CONTINUING) And then if you'll explain to me what MDU is doing here. Are you -- in your calculation on page 7 of 23, Statement N, explain to me how you're doing this.

A. Give me that cite.

Q. That same page that we were looking at.

A. Seven.

Q. Okay. So you're just taking from $7,988,000 for labor costs in 2001, you're putting in place a 3.15 percent increase for year 2002 and then you're projecting a 3 percent increase for January 1st, 2003?

A. That's correct.

COMMISSIONER WEFALD: Okay. Thank you.

MR. HOBERG: Commissioner Clark, any questions?

COMMISSIONER CLARK: Just a couple.

EXAMINATION

BY COMMISSIONER CLARK:

Q. When calculating the C ratio compa-ratio, is the term "market value," is that the same as market average? In other words, when you say 91 percent of the market value, is that saying you're 90 percent of the market average for a given

position or wages?

A. Essentially, that's correct. We're at midpoint market average or market value. It's the midpoint of that.

Q. Okay.

A. We're 91 percent of that.

Q. Got it. And that's companywide, it's across the board?

A. That's right.

Q. Would that follow that individual positions are typically at about that or are there certain areas of --

A. Lower and higher. And more lower than higher, though. Because if you took 100 percent, that would mean that everybody was right at the midpoint of their salary range or that market value of their salary range.

Q. Do you have any particular area of expertise that tends to be more of a problem where you are at with midpoint than others?

A. Well, if you read further, you'll see that the managers are actually lower paid, I think. That's probably where we have more of a problem.

Q. Do the C ratios or compa-ratios, include bonuses, or is that just salary?

A. No, that's just salary.

Q. Is there any way to get a handle on what the bonuses, kind of where that brings it? Because it would seem like if the company has a policy which is trying to move more toward bonuses, which in a lot of ways make sense because it's more incentive based and it has some tax advantages or some savings advantages, when you add those in, where do salaries fall?

A. Well, if you take the total compensation package, you know, and you look competitively, you'll see that in various classifications, they'll have different bonus amounts. Overall for mid managers, what we call mid managers -- executives are a little different -- mid managers, but we use about a 15 percent average and that's based on, again, study from Towers Perrin and --

Q. So explain, a 15-percent average means 15 percent of their total compensation package?

A. 15 percent of their base salaries.

Q. 15 percent of their base salaries is?

A. And that's really at risk. I mean, that's -- you know, they have to perform to get any of that.

Q. Okay. I think you're going to have to

explain this 15 percent again. It's 15 percent of their base salary?

A. Base salary, right. That's what they're eligible to receive.

Q. In bonus?

A. Up to 15 percent of their base salary and that's for the middle management.

Q. And you said that rate is comparable to other industry peers?

A. That's -- yeah. That's -- in fact, it's probably a little bit low. If you look at the study, they're going to come in somewhere between 17 and 22 percent.

COMMISSIONER CLARK: That's all I've got. Thanks.

MR. HOBERG: Thank you, Commissioner Clark. Commissioner Wefald.

FURTHER EXAMINATION

BY COMMISSIONER WEFALD:

Q. So if I'm to assume that in 2001 on this same page 7 of 23, Statement N, that a certain amount of dollars are already in 2001 for bonuses?

A. 2001?

Q. Mm-hmm.

A. Those are actuals, I think, aren't they?

Q. Those are actuals in 2001. The actual bonuses that were given in 2001.

A. Right. I'm assuming that's what they are. I didn't make this chart, but since that's past.

Q. So each year you're projecting to give more bonuses, if you put in the increase of the 3.15 percent, is that correct? In the first year to 2002 and 2003 you would be giving each year a greater amount -- have the potential to have a greater number of dollar bonuses in those three years?

A. Let me see if I can clear this up.

Q. Let's say there's $500,000 of bonuses in the first year.

A. Let's start with $1,000. It's easier for me to calculate. Let's say we have a $1,000 worth of -- well, first of all, let's say we have $2,000 worth of salary, period, and we give a 3 percent increase across the board to those $2,000, so that would be $60. So now we have $2,060. Now, if you assume -- you've got the 3 percent of 2,000 would be 60, 3 percent of 2,060 would be something a little more than that. So you're right in assuming that if you give increases, that providing -- and there's nothing guaranteed about these bonuses. If you hit your maximum, then your bonuses would also increase.

Q. But if Mr. -- is it Mr. Majoros who was discussing this in his testimony? Is it your understanding that he's recommending eliminating the entire dollar amount of bonuses out of 2001, or is he just recommending that there not be an increase in the dollar amount of bonuses that's included in 2001?

A. I'm not sure. 2001 is by us so now --

Q. Yes, last year. And your chart here is based on 2001 and then you're making an adjustment, reflects an average of 3.15 percent increase.

A. Over the actuals paid in 2001.

Q. Reflects average 3.15 percent increase reflecting average 2000, 2002 bonus.

MR. PEARCE: I think we may be getting stuck here. Perhaps Ms. Mulkern could come back because she's the one that prepared --

COMMISSIONER WEFALD: Okay. That would be good.

MR. PEARCE: Maybe you can get through this a little faster.

MR. HOBERG: Ms. Mulkern, do you want to come back up? Let's do it right now while we're on the subject. If you could stand up there by the mike, please.

MS. MULKERN: Can I describe maybe how we developed that labor increase?

COMMISSIONER WEFALD: Sure.

MS. MULKERN: Okay. We started with 2001 actual -- in developing a labor adjustment, we started with the actual gas utility labor expense, total company gas utility for 2001, and that contained the payroll over time, these commissions and bonuses, and we use that title. It really isn't bonuses. It kind of carries over from previous years. And looked at 2001, and then we looked at 2002, what was in the budget. And in 2001 we had a higher bonus payout and so if we stayed with the 2001 amount and increased that, really, we would be overstating. So we included a three-year average of bonuses and used a three-year average of bonuses for 2002, 2001, and 2000 and included that as the bonuses for 2002.

So the 3.1 percent -- 3.15 percent increase reflects a three-year average of bonuses in it. So the bonus level for 2000, indirectly 2002 that's embedded in that is less than was actual in 2001 because instead of using the actual bonuses, we restated it to a three-year average.

COMMISSIONER WEFALD: So there is money in

2001 here for bonuses and 2002 you altered the amount of bonus dollars in these and then you also figured a 3.5 percent increase, not only on the bonuses, but on all labor costs?

MS. MULKERN: The 3.15 increase for 2003 is net of the bonus. It's not on top of it. It's net of the change in bonus. So that's the overall increase in all labor and reflecting a three-year average.

COMMISSIONER WEFALD: All right. And then what happens in 2003?

MS. MULKERN: And then in 2003 we adjusted everything up by 3 percent. And that makes sense because everyone's wages are going up and so, generally, the bonus is based on the percent of base salary. So that base goes up and the bonus will go up. If I got, say, a .5 percent bonus in 2002 based on my 2002 salary and, hopefully, I would get a wage increase in 2003 and I got the identical percentage bonus, it would be higher cost because my wage has gone up. So it is appropriate to increase the bonus rate 3 percent, because the overall wages are going up, therefore, the bonus would go up also.

COMMISSIONER WEFALD: All right. I understand it. Thank you.

MR. HOBERG: Thank you, Ms. Mulkern. Any further questions then of Mr. Spratt? Mr. Diller.

MR. DILLER: I see it's after 5:00, but I do have a question.

EXAMINATION

BY MR. DILLER:

Q. Is it true, Mr. Spratt, that wage increases are a cause of inflation?

A. No.

MR. DILLER: I withdraw the question.

MR. HOBERG: Any further questions of Mr. Spratt? Thank you, Mr. Spratt. You've got one witness left?

MR. PEARCE: Call Richard Espeland. Should be very short, I think.

MR. HOBERG: Mr. Espeland, I just need to remind you also that you're still considered to be under oath from yesterday.

THE WITNESS: That's correct, yes.

MR. HOBERG: Mr. Pearce, please.

RICHARD A. ESPELAND,

having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. PEARCE:

Q. Mr. Espeland, for this case you prepared written prefiled rebuttal testimony, did you not?

A. Yes, I have.

MR. PEARCE: And that's been marked as Exhibit 28, I believe. I'll offer that exhibit and I have no further questions.

Q. (MR. PEARCE CONTINUING) Would you please give a summary of your testimony?

MR. HOBERG: Before you do, any objection to Exhibit 28?

MR. BINEK: No.

MR. HOBERG: Exhibit 28-55 is admitted.

Mr. Espeland, please.

THE WITNESS: Thank you. In my written testimony -- and I'll very briefly summarize and refer mainly to the attachments, which provides us supporting information, because I know in making rate case decisions what common practice is, sometimes needs to be supported. If you look at the Exhibit RAE-2, I provided two survey sources to support the common approach using a SERP or a supplemental income security plan for senior management.

If you look at page 2 of 3 of Exhibit RAE-2 you notice from the Hay survey under the left-hand column under non-qualified plans, it says, 74 percent of plan sponsors have some form of non-qualified retirement plan. So three-fourths of the employers have these types of plans. They're very common. Also, if you look at the right-hand column of the survey highlights, the second bullet from the bottom says, target retirement ratios fall into the 50 percent to 70 percent range, and so that a 50 to 70 percent replacement ratio for retirement income is very common.

On page 3 of 3 is another survey of another survey of another consulting company, Clark/Bardes Consulting. They also, if you look at the plan prevalence, have shown that in 2001 on the left-hand bar, 75 percent of the companies surveyed also have these type of plans. If you look up at the top introduction, the last -- on the right-hand column, about halfway through that paragraph, it says, the primary reason for adopting a SERP is the Omnibus Budget Reconciliation Act of 1993, which lowered calculations to 150,000. And at the time prior to that the index was 225,000. So they reduced by over a third the amount of compensation that could be

considered in a defined benefit pension plan. That was in part what caused these plans to be added.

If you then turn to RAE-3, the next page, which is a graph that shows the percent retirement replacement income, I've shown there on the top ones that qualified plans as to what percent replacement income they provide, and you can see 30,000 is 84 percent, and at the top level it's 20 percent, well below the 50 to 70 percent that is common.

So that's why we have our SISP program and that's why it's appropriate to include in the rates as a common practice as part of the total compensation program. And the bottom graph reflects how it changes when you add SISP. I believe the prior testimony said that we have an inverse relationship with our SISP where the lower level gets a smaller percentage replacement income under SISP and the higher level gets a higher percentage, and that's correct, but that's only a small part of the total picture. You've got to keep things in context.

There are four major parts to our retirement plan. Social Security, and you'll see the inverse relationship there where 40 percent out of the $30,000 level is provided by Social Security,

but only about 3 percent at the top level comes from Social Security. And same with the other plans. Our 401(k) plan has 20 percent provided at the lower income levels, and 8 percent at the higher level. Twenty-four percent comes from the defined benefit pension plan on the lower level and only 9 percent at the top level. That's why we have the SISP, to be fair and competitive and have a reasonable amount of replacement income at the 50 percent level at the top end, which is at the low end of the range of common practice.

Again, I want to emphasize as Mr. Spratt has commented, that we approach compensation in a total compensation approach. We can deliver $1,000 in a lot of different ways. We choose to offer base salary. We choose to have incentive pay so it's not a fixed cost, but it's only given if performance is there. And we choose to have benefits and other programs that provide for economic security. It's the most cost-effective way of doing -- delivering value to the executives and to the employees at all levels. And we could easily pay them all in base salary, all in base rate. It would not be the most cost-effective or the most incentivizing for good customer service.

That concludes my remarks.

MR. PEARCE: I'll offer Exhibit 28. I don't think I did before.

MR. HOBERG: You did.

MR. PEARCE: I didn't mark it. I have no further questions.

MR. HOBERG: Mr. Binek, any questions?

MR. BINEK: This has been covered pretty thoroughly, I think, and I'm going to resist the temptation of asking any questions. So I have no questions.

MR. HOBERG: Thank you. Commissioner Wefald, any questions?

COMMISSIONER WEFALD: I have no questions of this witness.

MR. HOBERG: Commissioner Clark, any questions?

COMMISSIONER CLARK: None. Thank you.

MR. HOBERG: Thank you, Commissioner. Mr. Diller, no questions? No one else has any questions of Mr. Espeland? Thank you, Mr. Espeland.

COMMISSIONER WEFALD: I have one for Mr. Spratt.

MR. HOBERG: Mr. Spratt, Commissioner Wefald would like to ask a question of you.

COMMISSIONER WEFALD: One more.

THE WITNESS: Am I still under oath?

MR. HOBERG: Yes, you are.

FURTHER EXAMINATION

BY COMMISSIONER WEFALD:

Q. Why should the Commission consider 2002 in an average for bonuses when you haven't even completed the whole year?

A. Because we started out last year and told our employees that there was going to be a bonus program. And in that bonus program we have objectives that they're meeting and there are certain financial objectives that we have to meet, as well as personal objectives. So in order for us to be able to keep our promise to our employees, I would like the Commission to do that.

Q. Well, we're not going to be approving anything that would go into effect for 2002. Our earliest date of the order would be --

A. 2003.

Q. Isn't that the year that we're looking at?

A. Yes.

Q. So it wouldn't make any difference what the Commission did for 2002. So we have to make our decision before the end of 2002 and you have to make

projections of what people are going to be getting, but how do we know you are actually going to be giving those bonuses or that people will actually meet the requirements by the end of the year? What I'm wondering is why we shouldn't just use the average of maybe 1999, 2000, and 2001, or maybe just 2000 and 2001, instead of -- if we are even considering adding bonuses and why we would even look at numbers from 2002 when they're not actuals?

MR. PEARCE: I think this is really Ms. Mulkern's area again. Probably she should address it.

MR. HOBERG: Ms. Mulkern, come back up again.

COMMISSIONER CLARK: We want you to sing Stairway to Heaven this time.

MS. MULKERN: We used an average of 2002, 2001 and 2000 because when we were preparing this case in March of 2002, the bonuses are generally paid out in February of each year. So when we prepared this case in March, we had the actual amount of bonuses that had been paid for 2002.

COMMISSIONER WEFALD: Okay. Thank you. That answers that question.

MR. HOBERG: Any additional questions of

Mr. Spratt? Thank you, Mr. Spratt. Is there anything else to bring to the attention of the Commission in regard to evidence in this matter? Mr. Pearce?

MR. PEARCE: Just, I guess, in the way of a general statement. There has been a lot of discussion on the depreciation study that's currently underway and, of course, it's our position that that may or may not have some effect in the future on rates, but really isn't critical for this case because we are operating now under a Commission-approved depreciation study from 1991 that we think is the appropriate one to be used. So that ongoing depreciation study certainly isn't critical. Now, it may or may not have any effect on rates in the future.

Also, I think it's appropriate to renew our motion. It's been taken under advisement, I think, that this proceeding is not the proper one to implement FAS 143 for ratemaking purposes.

MR. HOBERG: That's been taken under advisement, yes. Are you going to be providing the late-filed exhibits shortly?

MR. PEARCE: What sort of time frame? I think those can be done rather quickly.

MR. HOBERG: Probably within the next 15 days?

MR. PEARCE: Certainly, I would think. Even 10 or 15. Fifteen is fine.

MR. HOBERG: That would be appropriate, I believe. There's been some discussion about how to close this out and it's my understanding that both of the -- the staff and you want to file proposed findings of fact, conclusions of law and post hearing briefs?

MR. PEARCE: Yes.

MR. HOBERG: Mr. Binek; is that correct?

MR BINEK: Yes.

MR. HOBERG: Okay. We can do that within 30 days; is that correct?

MR. BINEK: When will the transcript be prepared?

MR. HOBERG: Are we preparing a transcript?

MR. PEARCE: Yes. And I think we should go off the record because the reporter indicated to me she prefers not to be pushed on the record as to the time.

MR. HOBERG: Let's go off the record.

(Discussion off the record.)

MR. HOBERG: Let's go back on the record.

MR. PEARCE: Maybe something like -- talking about the last week of October then, maybe.

MR. HOBERG: The Commission has until the 12th of December to issue a decision.

MR. BINEK: I was going to suggest possibly November 15 as a date for proposed findings and briefs.

MR. PEARCE: That's fine. Sure.

MR. HOBERG: That would give the Commission 30 days.

MR. BINEK: Just about 30 days.

MR. HOBERG: Okay. So you have them to the Commission by the 15th, not mailed or anything, to them by the 15th.

MR. PEARCE: Right, in their hands.

MR. BINEK: I can get them in their hands.

MR. HOBERG: You can do that.

MR. PEARCE: We have messengers. I can do that, too.

MR. HOBERG: Okay. So proposed findings of fact, conclusion of law and briefs to the Commission by November 15. Late-filed exhibits within 15 days. Is there anything else that needs attention at this time? Mr. Pearce?

MR. PEARCE: Nothing for me.

MR. HOBERG: Mr. Binek?

MR. BINEK: No.

MR. HOBERG: Thank you. Commissioner Wefald, did you have any closing statements to make?

COMMISSIONER WEFALD: Thank you for a good hearing.

MR. HOBERG: Thank you. Commissioner Clark?

COMMISSIONER CLARK: Thank you.

MR. HOBERG: Let's close this hearing. It's approximately 5:30.

(Concluded at 5:30 p.m., the same day.)

CERTIFICATE OF COURT REPORTER

I, Linda L. Gingery, a Registered Professional Reporter,

DO HEREBY CERTIFY that I recorded in shorthand the foregoing proceedings had and made of record at the time and place hereinbefore indicated.

I DO HEREBY FURTHER CERTIFY that the foregoing typewritten pages contain an accurate transcript of my shorthand notes then and there taken.

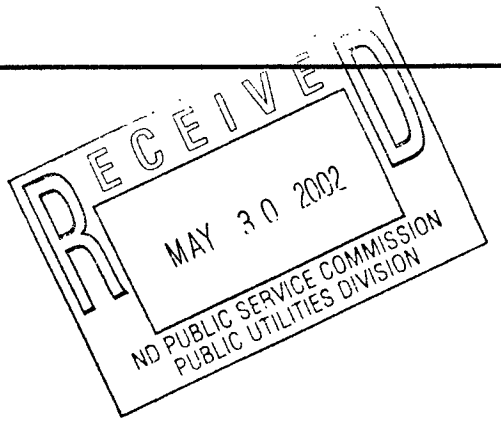
Dated at Bismarck, North Dakota, this 21st day of October, 2002.

Linda L. Gingery
Registered Professional Reporter

LaCapra Associates

Energy Planning & Regulatory Economics

May 30, 2002



Mike Diller
Director of Accounting
North Dakota Public Service Commission
State Capital, 12th Floor
Bismarck, North Dakota 58505-0480

Re: Request for Proposals Case No. PU-399-02-183

Dear Mr. Diller:

La Capra Associates is pleased to offer this proposal, (an original and five copies), to provide expert advice to the North Dakota Public Service Commission in the areas of cost of service and rate design and to provide expert witness services as necessary.

La Capra Associates is a Boston-based consulting firm specializing in regulatory policy, ratemaking, energy planning, and market analysis in the gas and electric industries. We have been in business for over 20 years and are well established throughout the Northeast U. S. and in many other states. We have extensive experience working with regulatory commissions and consumer advocates and have substantial hands-on experience with the type of cost of service and rate design work described in the request for proposals. We have provided expert testimony in all areas of utility ratemaking and have developed and sponsored entire tariffs for several utilities drawing on experience with utility cost functionalization, cost classification, cost allocation and rate design.

We look forward to hearing from you.

Regards,

GR McCluskey

George McCluskey
Senior Consultant

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Response to Request for Proposal

by LaCapra Associates

05/30/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

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PROPOSAL TO PROVIDE CONSULTING SERVICES

TO

NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU - 399 - 02 - 183

PRESENTED BY

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MAY 30, 2002

Proposal To Provide Consulting Services

To

North Dakota Public Service Commission

Case No. PU - 399 – 02 - 183

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1. Executive Summary

La Capra Associates ("La Capra") is pleased to offer this proposal to provide expert advice and witness services to the North Dakota Public Service Commission ("Commission") in three of the five subject areas specified in the May 10, 2002 Request for Proposal ("RFP"); namely, level of investment, cost of service and rate design.

La Capra is a Boston-based consulting firm specializing in energy planning, market analysis, and regulatory policy in the United States energy industries. We have been in business for over 20 years and have experience across the U. S. and in other countries. We have extensive experience working with public entities such as regulatory commissions and consumer advocates and have substantial, hands-on experience with the type of cost of service and rate design work described in the RFP. La Capra has provided expert testimony in all areas of utility ratemaking and has developed and sponsored entire tariffs for gas and electric utilities, drawing on experience with utility cost identification, functionalization, classification, and rate design. Our experience with cost of service work includes both projected and historical test year periods. La Capra has assembled a team of highly experienced professionals that can work with the Commission Staff to ensure that the project is completed successfully and efficiently. Our team offers experience and depth in:

1. Revenue Requirements Analysis: Our team has experience conducting revenue requirements analyses of gas and electric utilities. Those analyses have included the full range of cost analysis and projections, including weather normalization of revenues and costs. We have critiqued utility revenue requirement requests for public advocates and commissions in many jurisdictions
2. Retail Rate Design: Our team members have, individually and collectively, extensive experience with retail rate design in the gas and electric industries. We have supported the development of rates that reflect appropriate balancing of various rate design objectives. This has been based on consideration of cost causation, of public goals, and of existing rate structures.
3. Fully Allocated Cost of Service Studies: Our team has extensive experience conducting allocated embedded cost of service studies. Specifically, the senior members of our Project Team have experience that includes: data acquisition; creating models to develop cost allocation factors from load data; establishing allocation factors that best reflect cost causation and consideration of all rate

design principles; understanding the data and its limitations; understanding the limitations of joint or common cost allocation mechanisms; and phasing in difficult rate transitions. These individuals are supported by experienced analytical staff.

4. Marginal Cost Studies: La Capra's Project Team has a sound understanding of the principles of marginal cost pricing and the application of those principles to gas and electric utility industries. We have developed marginal cost studies for all gas functions.

5. Expert Witness Services: La Capra's Project Manager and Task Managers have provided expert witness services for public and private entities throughout the U.S. A detailed list of these services is included in the biographies of the appropriate staff.

George McCluskey will be La Capra's Project Manager for our work on this project. He is a ratemaking specialist having experience with La Capra and previously with the New Hampshire Public Utilities Commission. Robert Hix, a Managing Consultant, will be our expert witness on cost of service and rate design matters. Mr. Hix, a former Chair of the Colorado State Commission, has extensive regulatory background and experience working for various public agencies that will allow him to speak authoritatively on a broad range of cost of service and rate design issues. We have assigned a number of other experienced professionals and staff to ensure the project is completed successfully and on time.

We propose a scope of work with a not-to-exceed budget of $39,640, including expenses, to cover the investment, cost of service and rate design issues referenced in the RFP. The details of this budget are provided in Appendix C to our proposal. We will work closely with the Commission Staff to effectively manage the scope and cost of the case.

Dan Peaco, La Capra's Managing Director, is authorized to negotiate and contractually bind the firm for services to the Commission. Please contact Mr. Peaco for further information on this proposal, as follows:

Daniel Peaco, Managing Director
Suite 855, 333 Washington Street, Boston, MA 02108
Phone: (617) 557-9100 x13
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E-mail:dpeaco@lacapra.com

2. Technical Description

2.1 Initial Scoping Exercise

La Capra Associates is proposing to engage the Commission Staff in an initial scoping exercise, (i.e., in advance of developing testimony). The purpose of this exercise would be to explore and understand the Staff's objectives for the case, and the environment in which it operates. This will better enable us to perform the tasks specified in this proposal.

2.2. Investment or Rate Base Tasks

The purpose of this task is to define a level of investment that is an appropriate basis for the return on the utility's investment. The historic rate base is usually considered the starting point, but we would analyze the most recent investments in plant to ensure that they were in response to actual needs. Utilities can accelerate certain investments in order to inflate specific rate requests. The initial analysis of increases to rate base focuses on how investment compares to the Company's past rate of investment, and also how the investment has compared to capital budgets. We would also investigate through discovery and reviewing annual reports to the Commission whether there are extraordinary circumstances that could explain a change in investment. La Capra Associates would consult with Commission Staff to gain a better understanding of the North Dakota environment and the effect it would have on recent and projected investment. For instance, environmental problems or requirements might make additional investments necessary. If the Company has made extraordinary investments, it should be able to justify them by means of cost-benefit analysis. We would apply the same type of analysis that was applied to recent investment would also be applied to projected investment. Another task in examining the level of investment is determining whether investment has been defined appropriately. For instance, some large expenditures could be treated as amortizable expenses rather than rate base. In this task we would also investigate whether retirements, salvage and capital contributions have been accounted for.

2.3. Cost of Service Tasks

After rate base and the return on rate base are determined, the utility's cost of service is computed by determining the appropriate level of remaining costs to reflect the utility's ongoing operations. Those costs then should be allocated to retail customers and among rate classes.

Normally, the level of operating and maintenance expenses actually incurred is not subject to much debate, although there may be issues regarding how those costs are classified. More controversial, and requiring more critical analysis, will be proforma adjustments to those expenses, and any changes that purport to reflect changed utility operations. Forward test years depend on realistic projections of all costs and revenues, both of which should be carefully scrutinized. We would initially compare the rate of increase in different cost accounts with recent actual experience, with the appropriate price inflators, and with past Commission directives to gas utilities. For instance, if utilities had been directed to reduce unaccounted for gas, (losses), this might explain increases in some types of expense or even capital expenditures.

With gas utilities, the impact of weather on both gas costs and on utility revenues is a very significant issue. A northern territory with a great deal of gas heat will be very sensitive to weather. La Capra has extensive experience with estimating normal weather, projecting sendouts and weather normalization of revenues. This experience will contribute to our assessment of the Company's presentation. We would examine the Company's basic assumptions and request through discovery any tests, such as backcasting, of their methodology. We understand that they use a protected model, which makes it somewhat more difficult to determine how normalization is actually performed. Although the model is large and sounds complicated, it appears to be based on a fairly simple base use versus heat use structure. This approach can misstate weather sensitivity during different temperature ranges, and may not appropriately reflect the lag between sendout and sales. Weather normalization is complicated by the significant lag between gas sales and gas sendout if data is reported on a calendar year basis. We could perform an alternative analysis of weather normalization if this was a major issue in the case, but we are not including the cost of this potential effort in our current cost proposal. Revenues also must be normalized for changes in the number of customers and changes in rates during the historic and future year, which may be through the Company's same model or may be a separate computation. This is not a difficult task, so the critique of it consists of insuring that the basic assumptions are complete and reasonable.

2.4. Rate Design Tasks

There are a number of principles that are normally considered in rate design. Rates should be fair and equitable; they should allow for the collection of legitimate costs; they should be relatively simple, which facilitates customer understanding of the rates; rates should assist

with, or at least not conflict with, social goals set by the Commission; rates should provide price signals that encourage efficient use of the product, and there should be concern for rate continuity. All of these principles should be considered, although compromises between principles may be necessary. This phase should begin with discussions between ourselves and the Staff that clarify the Commission's basic principles. Our understanding of the Commission's goals will guide our recommendations when there are conflicts between various principles.

The principle that rates should be fair necessitates examining the relative costs of serving different customer classes. This would begin by separating the costs of serving transportation customers and removing them from retail rates, so that smaller jurisdictional customers do not subsidize the large wholesale customers. The next separation or allocation of costs is between customer classes. While gas allocation methodologies are not as developed as electric methodologies, most costs can be considered to be caused by both commodity and peak usage. There are several methodologies that may accomplish this. We would examine the Company's methodology to determine if it was reasonable. Whether data on peak usage by gas customers, which is used in the allocation process is accurate, may be an issue, and is one that we have addressed numerous times. Other costs are more related to the number of customers, but those costs need to be weighted appropriately. Such costs as meter costs or customer marketing costs are likely to be quite different between rate classes. If there are significant geographic or zonal differences in costs, these need to be addressed in cost allocation and rate design. For instance, if some customers own their own services and meters both plant, expenses, and service revenues will be different from those customers where the Company owns all plant to the customers' premises.

Evidently the Company is attempting to reduce the variability of their net revenues due to weather variability. For this purpose they have proposed a very large increase in the customer charge. The customer charge is not a very useful price signal, and increasing it significantly will create much larger bill impacts on small customers than on large customers. The Company should be required to provide some demonstration that this proposal would provide some benefits to consumers, and any such change should be modified at least until bill impacts were

acceptable. We have found that gas distribution costs are largely a function of customer peak demands, so we would not expect to find that even accurate cost recovery would support very large reduction in customer costs and equivalent reductions in usage sensitive charges.

La Capra will also review and analyze relevant Commission orders relating to rate design issues and, where appropriate, prepare an assessment of the implications of such orders for this case. Based on the results of this assessment, La Capra will develop, in conjunction with the Staff, rate design proposals that meet the Commission's regulatory goals and objectives. We would also investigate the potential bill impacts of the proposed rate changes.

3. La Capra Corporate Experience

3.1 Introduction to La Capra Associates

La Capra is a Boston-based consulting firm specializing in regulatory policy, energy planning and market analysis in the natural gas and electricity industries. We provide strategic planning advice to policy makers and senior managers along with expert, technical analysis to support policy, investment, and operational decisions. Since our founding in 1980, we have earned a reputation for practical and objective advice and for timely, accurate, and innovative analyses.

La Capra provides services to the full range of organizations involved with energy markets – regulatory agencies, public and private utilities, energy producers and traders, financial institutions and investors, consumers, and public policy and research organizations. Over the past several years, we have become recognized for our ability to help our clients with the many new challenges and opportunities that are presented by deregulation of gas and power markets and the restructuring and privatization of utilities. Throughout our history, we have provided services at the forefront of change in the industry, including areas such as marginal cost pricing, integrated resource planning, competitive procurement of independent power supplies, and demand-side management.

La Capra's expertise in energy matters is interdisciplinary. Our technical skills include forecasting models and methods, economics, finance, law, management, planning, pricing, engineering, procurement, and contracts. We are able to support our planning and policy work with detailed technical analysis that often requires complex market system modeling or custom model applications. We also offer skills in market rules, regulations, policy, and negotiations. We regularly provide services ranging from broad policy development to analysis of major investments to short-term planning and operations. Our work frequently leads to presentation of expert testimony or opinion before state or federal regulatory agencies, financial institutions, and corporate management and boards and has consistently withstood detailed scrutiny.

3.2 La Capra Associates References

The following client references can provide additional information about La Capra Associates as a firm and the individuals that we are proposing to work with the Commission on the requested tasks.

Client: **Arkansas Public Utility Commission**

Service: **Rate Design, Price Estimation and Stranded Cost Calculations**

La Capra Associates was retained by the Arkansas Public Service Commission to assist staff in its efforts to implement electricity restructuring legislation in that State. We assisted staff in establishing policy positions covering a range of topics, including: guidelines for market power filings; standard service package design; a decision framework and recommendations for additional utility services to be made competitive; and the proper sequencing of regulatory activities that would be required to achieve retail competition.

In the fall of 2000, La Capra's report to the Commission addressed the conditions necessary for the effective implementation of retail competition, leading to the Commission and the Legislature deciding to delay the start of electric retail access in Arkansas. On behalf of the Staff of the Arkansas Public Service Commission, La Capra prepared expert testimony and analysis that contributed to the evaluation of Entergy Arkansas Inc.'s stranded cost estimates and to its request to continue the accelerated recovery of the Grand Gulf nuclear investment. Testimony discussed the generally accepted approaches for deriving the fair market value of electric generating assets, focusing on the comparable sales methodology used by EAI.

Client Reference: Diana Brenske,
Manager of Electric Restructuring
(501) 682-5656

Client: **Valley Gas Company**

Service: **Cost of Service, Allocation and Rate Design**

La Capra Associates originally negotiated a gas transportation rate with Valley Gas on behalf of a large industrial customer. We were later retained by Valley Gas to advise on unbundling all gas services, performing an allocated cost of service study, and designing new rates. We developed testimony on these issues, and then Valley Gas was acquired by Providence Gas, which is itself a subsidiary of a larger gas company. Ms. Partridge as CFO of Valley Gas worked closely with us. She subsequently was hired by Providence Gas.

Client Reference: Sharon Partridge,

Vice President, Regulatory Affairs
Providence Gas Company
(401) 272-5040

Client: **New Hampshire Public Utilities Commission**

Service: **Power Portfolio Auction, Stranded Cost Analysis and Rate Design**

La Capra was retained by the New Hampshire Commission to assist its Staff in a restructuring case that combines the sale of the utility's power supply contracts with a base rate case to establish the level of new unbundled distribution rates. La Capra's responsibilities include advising the Commission on the divestiture process for the power contracts portfolio, the competitive solicitation of supplies for Standard Offer Service, the calculation of stranded costs, the allocation of the distribution revenue requirement to classes, and the design of unbundled distribution rates.

Client Reference: Mary Coleman,
Assistant Director, Electricity Division
(603) 271-6039

3.3 Additional Relevant Experience

This section of the proposal contains representative examples of public and private clients for whom we have conducted similar or related work, along with associated contact information for our references.

Client: **Various Public and Private Entities**

Service: **Cost of Service and Rate Design Studies**

La Capra has broad experience in the area of cost of service and rate design studies, which sets the foundation for our ratemaking advisory services. Our work in these areas has centered on three areas: the development of embedded cost of service and rate design studies, the development of marginal cost of service studies, and special projects. In the area of embedded cost of service studies, we testified in numerous proceedings on the selection of cost allocation factors for demand-related generation, transmission and distribution costs. In the area of rate design, we performed conventional, time-differentiated bundled and unbundled studies. La Capra personnel have also supervised the development of computerized loss analyses and load research based class demand analyses. Working with the results of these studies, we performed

conventional rate designs as well as developed unbundled, time-of-day, load management, conservation, interruptible, curtailable and experimental rate designs.

Client: **Various Public and Private Entities**

Service: **Expert Witness Testimony on Cost of Service and Rate Design**

Across two decades, La Capra has worked for dozens of regulatory agencies, consumer advocates, user groups, investor-owned utilities, and cooperative utilities and has provided expert testimony in all areas of utility ratemaking. We have developed and sponsored entire tariffs for many private and public utilities, drawing on experience with utility cost identification, functionalization and classification, and rate design.

Client: **Various Gas Utilities**

Service: **Regulatory Rules, Policy Issues, System Reliability**

Over the years, La Capra has advised numerous small and large gas companies on a wide range of ratemaking issues, including design day and design year supply reliability standards, the phase-in of large distribution plant investments, cost-based firm transportation rates, load forecasting, reorganization of all commercial and industrial customers into new rate classes, and cost of service and rate design for transportation rates. Finally, we developed a daily gas dispatch model for a large gas company, which was used to calculate marginal gas costs by season and to allocate gas costs.

Client: **Colonial Gas Company**

Service: **Regulatory Rules, Policy Issues, System Reliability**

La Capra has assisted Colonial with numerous issues in several rate filings and related cases over the years. We developed a daily gas dispatch model for the Company, which was used to calculate marginal gas costs by season and to allocate gas costs. We custom designed an allocated cost of service model and utilized this to allocate costs between users. We then designed new rates and reorganized the Company's commercial and industrial rate classes. Subsequently, we redesigned Company rates based upon marginal cost principles using an allocated cost-of-service study. More recently, we assisted the Company in developing various analytical enhancements for another rate case, including converting class sales data (including a billing lag) to weather-adjusted calendar data for use in revenue normalization and setting rates. La Capra Associates also assisted the Company in the development of a DSM plan, including development of avoided gas supply and distribution costs, and directed an analysis of the cost-effectiveness and non-price attributes of the company's new pipeline transportation contracts.

Client: **Texas and Illinois Clients**

Service: **Unbundled Delivery Service Rates**

La Capra has relevant experience in delivery service rate cases. Several members of the Project Team were involved in proceedings to establish unbundled transmission and distribution rates for three Texas jurisdictional utilities, and Ms. Smith also addressed distribution cost allocation and rate design in Illinois.

Client: **Maine Office of the Public Advocate**

Service: **Rate Design Analysis**

La Capra testified in Maine on the development of marginal cost studies, on the use of marginal cost analysis for ratemaking, and also on performance based rates elsewhere.

4. Project Management and Key Personnel

4.1 Management

La Capra has assembled a highly qualified team to manage and implement the work tasks described in the RFP. George McCluskey will serve as project manager. In this role, Mr. McCluskey will be responsible for project oversight and scheduling, assignment of tasks to the La Capra project team, and ensuring that project deadlines are met. He will maintain regular communications with the Commission Staff, in coordination with La Capra's Task Manager, regarding the management of the La Capra work. Mr. McCluskey will coordinate with the Staff to prepare scope, budget and personnel assignments for the specific work tasks to be conducted.

Mr. McCluskey will work closely with Robert Hix as the Task Manager. Mr. Hix, and Mr. McCluskey, will have day-to-day responsibility for the tasks identified in our proposed scope of work. They will also be responsible for coordinating the involvement of other required La Capra personnel and will serve as the day-to-day contact with the Commission Staff on their respective projects.

4.2 Personnel

In addition to Mr. McCluskey, the Project Team includes the following La Capra personnel:

La Capra Task Manager

Mr. Hix will participate in the preparation of testimony that addresses all of the issues covered by our scope of work and will be responsible for the presentation of that testimony before the Commission. While serving as Chair of the Colorado Commission, and before that with the Colorado Office of Consumer Counsel and Public Service Company of Colorado, Mr. Hix gained extensive experience analyzing the revenue requirements and rate design filings of gas and electric utilities. That experience includes reviewing and critiquing cost of gas adjustment clauses and models for developing weather normalizing adjustments to test year billing determinants and net revenues. Mr. Hix also participated in the review and approval of gas purchase plans for Colorado gas utilities. Additionally, Mr. Hix evaluated the cost structures of all ten of natural gas utilities in Colorado and as PUC Chairman implemented a rule that required gas utilities to disclose to consumers the components of their rates, such as gas cost, upstream pipeline cost and local delivery cost.

La Capra Senior Advisors

Mr. McCluskey and Mr. Hix will have senior advisors from our firm available to assist with policy and technical issues. Lee Smith, a Managing Consultant, will provide advice on economic, technical and policy matters. In addition, Dan Peaco, La Capra's Managing Director, will be available for consultation to provide support for the management and policy direction of the project as needed.

La Capra Analytical and Research Staff

The project teams will also include analytical staff from La Capra, as needed, under the direction of the task managers. The following individual will be the primary staff person for this work:

Arthur Freitas, Analyst, will serve as the primary analytical support to the task managers. Mr. Freitas has over 4 years experience in the energy industry, in both natural gas and electric markets. His relevant experience includes embedded cost of service analysis for natural gas and electric utilities, performance based ratemaking analysis, rate design analysis, unbundling analysis, and natural gas and electric market price forecasting.

Brief biographies for the above individuals are included in Appendix A. Biographies for other personnel available to assist can be provided, as needed. Full resumes of the professionals providing services are included in Appendix E.

5. Cost Proposal, Timeline and Billing Rates

La Capra has prepared a not-to-exceed budget that corresponds with three of the five tasks specified in the RFP. The details of that budget by task and project team member are provided in Appendix C to this proposal. La Capra will be happy to suggest modifications to the scope of work to provide additional services not currently reflected in the proposal. If it should be requested by Staff, La Capra could perform an independent cost allocation on weather normalization using our models at an additional cost. This would have to be agreed upon by Staff.

As discussed above in Section 2.1, we propose to begin with an initial scoping session conducted via telephone, the purpose of which is to ensure the La Capra and the Staff teams have a common understanding regarding the goal and objectives for this case. The budget for this work is $2,440.

The Investment/Rate Base portion of the scope of work is described in Section 2.2. and summarized in Appendix C. The budget for this work is $4,520, excluding the cost of preparing and presenting testimony that explains our conclusions and recommendations.

The Cost of Service portion is described in Section 2.3 and summarized in Appendix C. The budget for this work is $6,360, excluding the cost of preparing and presenting testimony.

The Rate Design portion of the scope of work is described in Section 2.4. and summarized in Appendix C. The budget for this work is $7,380, excluding the cost of preparing and presenting testimony.

With the addition of the costs to prepare and present testimony, respond to interrogatories, attend hearings, and prepare cross examination and findings of fact, we propose a total not-to-exceed budget of $39,080, excluding expenses. This budget assumes that the work will begin in June 2002 and will be completed October 2002. Invoices for payment of services will be prepared and submitted quarterly based on work completed to date and will be payable within 30 days of receipt of invoice. La Capra bills only for direct labor and expenses. If, as discussed above, modifications to the scope of work are requested, we would make appropriate adjustments to the budget based on the billing rates in Appendix B.

6. Equal Employment Opportunity and Americans with Disabilities Act Requirements

La Capra Associates does not discriminate against any qualified employee or applicant for employment because of race, color, national origin, ancestry, age, sex, religion, physical or mental handicap, or sexual orientation. La Capra Associates agrees to comply with all applicable Federal and State statues, rules and regulations prohibiting discrimination in employment including, but not limited to: Title VII of the Civil Rights Act of 1964; Section 504 of the Rehabilitation Act of 1973; the Americans with Disabilities Act of 1991; and M.G.L. c.151B.

Signed: David Pasco

Title: Managing Director

Date: May 29, 2002

7. Conflict of Interest

La Capra has had no business relationship with Montana – Dakota Utilities Company. Also, La Capra will commit that it will not develop such a relationship for a period of one year following termination of this assignment. La Capra does, however, have an agreement with El Paso Pipeline Company to monitor the activities of the Wyoming and Colorado regulatory agencies. El Paso is a partial owner of the Alliance Pipeline Company, a FERC jurisdictional interstate utility that has operations in North Dakota.

APPENDIX A

Brief Biographies

GEORGE MCCLUSKEY

Senior Consultant

Mr. McCluskey is a ratemaking specialist with over 20 years experience in utility economics, including approximately three years reviewing the activities of government owned generation and distribution companies in England. Since joining La Capra Associates in 1999, Mr. McCluskey has provided advice to several clients on a variety of subjects, including stranded cost analysis, rate functionalization and classification, RTO formation, and asset valuation. Prior to joining La Capra Associates, Mr. McCluskey was employed by the New Hampshire Public Utilities Commission ("NHPUC" or "Commission") where he held the positions of Director of the Electric Utility Restructuring Division, Manager of Least Cost Planning, and Gas and Electric Utility Analyst. While at the NHPUC, he testified as an expert witness in numerous gas and electric utility proceedings, including base rate and gas cost adjustment proceeding. Mr. McCluskey also testified on the design of gas transportation rates before the NHPUC and on wholesale ratemaking issues before the FERC. Prior to joining the NHPUC, he worked in England as a pricing policy specialist for the Electricity Council, primarily on the design of retail rates for electricity distribution boards.

Mr. McCluskey's gas related experience includes:

Rate Unbundling - On behalf of the Staff, he prepared and presented direct and supplemental testimony in a proceeding to establish NHPUC policy on the unbundling of firm and interruptible gas services and the establishment of gas transportation rates for commercial and industrial customers.

Purchase Gas Adjustment - He directed the evaluation of numerous purchased gas adjustment filings. This work required a knowledge of gas utility procurement practices and procedures as well as the terms and conditions of available gas supplies, which included firm and interruptible interstate pipeline sales and transportation services, spot market and contract purchases, underground storage services, and local LNG and propane-air systems.

Marginal Cost Pricing – Mr. McCluskey directed the Commission's Gas Rate Design Investigation into the application of marginal cost principles to gas utility ratemaking. He also prepared and presented expert testimony for Commission Staff that addressed areas of disagreement including the methodology for calculating production-related marginal costs and the determination of class revenue requirements.

Embedded and Marginal Cost Analysis – He presented expert testimony on the revenue requirement and rate implications of embedded and marginal cost-of-service studies prepared by two New Hampshire gas distribution companies.

Interruptible Rate Design - On behalf of Commission Staff, he prepared and presented expert testimony on the economic evaluation of a new interruptible rate design for large industrial consumers.

Standby Sales Service – He prepared and presented testimony on ratemaking issues associated with the development of a standby sales service for firm gas transportation customers.

Special Contracts - He directed the economic evaluation of a proposed special contract for a large business customer in New Hampshire.

Investment Appraisal - On behalf of the Commission Staff, he prepared and presented expert testimony on investment appraisal guidelines for discretionary natural gas capital projects. The guidelines were applied to a new, large gas pipeline that delivered natural gas service to an area of New Hampshire previously served by a propane-air system.

ROBERT J. HIX

Director, Denver Office / Managing Consultant

Robert J. Hix joined La Capra Associates as Managing Consultant and Director – Denver Office, to establish a stronger presence in the West. His experience enhances the organizations' ability to meet client needs efficiently in the areas of ratemaking and utility planning, distributed generation, renewable energy public policy and energy efficiency. Prior to joining La Capra Associates, Mr. Hix was appointed Colorado Public Utilities Commission Chairman by Governor Roy Romer. His term expired on January 8, 2001. He is a member of the Advisory Council to the Board of Directors of the Electric Power Research Institute and is a member of the Adequacy Committee of the North American Electric Reliability Council. Previous to his appointment, Mr. Hix was a Senior Engineering Analyst with the Colorado Office of Consumer Counsel, which represents residential, small business and agricultural customers on issues before the Public Utilities Commission. As Senior Engineering Analyst, Mr. Hix testified as an expert in engineering and rate matters at hearings before the Public Utilities Commission. His primary role was to determine the policy and regulatory implications of rate changes and cost allocation among various customer classes. He held various positions at Public Service Company of Colorado from 1971 to 1983. He began his career with Public Service Company as a field engineer responsible for electric distribution engineering projects and negotiations with electrical contractors. He also served in the Rates and Regulations Division where he was responsible for certain electric and natural gas rate filings with the PUC and special rate schedules with the Federal Power Commission, as a member of the Special Projects Division which initiated efficiency and cost control measures within the company, as the Electric Power Contracts Administrator and as a staff assistant to the Manager of Electric System Planning.

LEE SMITH

Senior Economist/Managing Consultant

Ms. Smith has worked on cost allocation and rate design issues for both electric and gas utilities in Massachusetts, Maine, New Hampshire, Kansas, Rhode Island, Pennsylvania, and South Dakota. She developed and presented testimony on cost allocation and rate design for a number of gas distribution utilities. Ms. Smith addressed functional separation and unbundled gas and electric rates in Massachusetts, Arizona, Pennsylvania, Vermont, Arkansas and Maryland. In Pennsylvania, Ms. Smith presented testimony for the Pennsylvania Office of the Consumer Advocate that responded to the rate unbundling requests of all eight investor-owned utilities. Recently, she assisted the Hawaii Office of the Consumer Advocate in settling issues regarding electric backup rates that would allow the installation of gas cogeneration. She has testified on appropriate customer class designation for gas companies. Prior to her employment at La Capra, Ms. Smith was Director of Rates and Research at the Massachusetts DPU, where she oversaw the rationalization of rates based on embedded cost allocation and marginal cost ratemaking principles.

Ms. Smith's gas related experience includes:

Cost of Service and Rate design work – She advised, prepared reports, and presented testimony on cost of service, marginal cost, rate design, and phase-in of large investment for Colonial Gas, Essex Gas, Berkshire Gas, North Attleboro Gas, Blackstone Gas, and Valley Gas.

Gas supply issues - Ms. Smith assisted in developing a gas supply sendout model for marginal cost analysis for Colonial Gas and Berkshire Gas; developed demand side management program for Colonial Gas and Essex County Gas; issued RFPs and negotiated gas supply contracts for Blackstone Gas Company.

Weather normalization methodologies and load forecasts – She developed planning standards and load forecasts for Essex County Gas, North Attleboro Gas, and Blackstone Gas; assisted Colonial Gas in creating daily load forecast and weather normalization model.

Testimony for public entities – She testified on gas cost of service, gas planning and rate design in Massachusetts, Vermont, Kansas, and Washington D.C. for public entities.

DANIEL PEACO

Managing Director

Daniel Peaco is an electric industry planning specialist with twenty years of experience. His expertise includes electric industry restructuring policy, power markets and marketing, strategic planning, pricing and price forecasting, power procurement and contracts, and power systems planning. He was formerly the Manager of Power Supply Planning for Central Maine Power Company.

His recent experience includes expert testimony on: economics of power contracts in litigation (ME, VT); economic analysis of the benefits of retail competition (AR); valuation of generation assets (OH, ME), stranded cost analysis (PA, OH), regional reliability forecasts (New England); standard offer and default service policy (AR, MA).

ARTHUR FREITAS

Analyst

Arthur Freitas joined La Capra Associates in May of 2000. Since joining the firm he has performed analyses in a number of areas. These include analysis of a cost of service study for a rate case involving an electric distribution company, economic feasibility study of various renewable technologies in connection with the Massachusetts Renewable Portfolio Standard, and fuel price forecasts to be used as inputs for a forecast of electricity prices in the New York power market. Before joining La Capra, Mr. Freitas worked as a rate analyst for Boston Gas Company where he was involved with preparing the Cost of Gas Adjustment Factor and the Performance Based Regulation filings for the state regulatory agency, as well as numerous other financial analyses and forecasts.

APPENDIX B

La Capra Associates Billing Rates

Principal	$210.00/hr
Managing Director	$190.00/hr
Managing Consultant	$180.00/hr
Senior Consultant	$150.00/hr
Consultant	$135.00/hr
Senior Analyst	$120.00/hr
Analyst	$100.00/hr
Research Staff	$ 75.00/hr

BUDGET PROPOSAL FOR NORTH DAKOTA PUBLIC SERVICE COMMISSION

(Table Identifies Labor Hours, Unless Designated $)

	Project Manager G. McCluskey	Managing Consultant R. Hix	Managing Consultant L. Smith	Analyst A. Freitas	Totals
Labor Rates	$150	$180	$180	$100	
PHASE 1: ANALYSIS OF FILING					
Review previous orders, initial discussion with Staff	4	4	4	4	16
Task Subtotal	4	4	4	4	$2,440
Review and Analyze Investment	2	4	2	4	12
Prepare Discovery and Review Responses	2	4		4	10
Prepare Monthly Reports On Rate Base Conclusions	2	2			4
Discuss Conclusions With Staff	2	2			4
Task Subtotal	8	12	2	8	$4,520
Review and Analyse Cost of Service	4	8	2	2	16
Prepare Discovery and Review Responses	4	6	2	4	16
Prepare Monthly Reports On Cost of Service Conclusion:	2	2			4
Discuss Conclusions With Staff	2	2			4
Task Subtotal	12	18	4	6	$6,360
Review and Analyse Rate Design Proposals	2	8	4	4	18
Prepare Discovery and Review Responses	2	4	6	8	20
Prepare Monthly Reports On Rate Design Conclusions	4	2			6
Discuss Conclusions With Staff	2	2			4
Task Subtotal	10	16	10	12	$7,380
Phase 1 Subtotal	34	50	20	30	$20,700
PHASE 2: HEARINGS					
Prepare Written Testimony	16	32	8	4	60
Respond to Interrogatories	4	8	2	4	18
Attend Hearings		16			16
Assist Staff Prepare Cross-Examination	4	4	2		10
Assist Staff Prepare Findings of Fact	2	4			6
Phase 2 Subtotal	26	64	12	8	$18,380
Totals for Labor	60	114	32	38	$39,080

Expense Budget	
Number of person	1
Number of overnig	1
Travel	$400
Lodging/Day	$100
Meals/Day	$30
Totals	$560

TOTAL ESTIMATED BUDGET $39,640

APPENDIX D

Sample Work Product

A. Burlington Electric Department

Testimony analyzed the firm transportation rate filed by Vermont Gas Systems.

B. People of the State of Illinois and the Citizens Utility Board

Submitted testimony rebutting the testimony filed by Illinois Power Company relating to rate design issues.

TESTIMONY OF LEE SMITH FOR BURLINGTON ELECTRIC DEPARTMENT

Q. **What is your name and business address?**

A. My name is Lee Smith, and I work for La Capra Associates, 333 Washington St., Boston, Massachusetts.

Q. **What is your occupational experience?**

A. I am a Managing Consultant at La Capra Associates. I have been with this energy planning and regulatory economics firm for 15 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My CV is attached hereto as Exhibit BED-1.

Q. **On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Burlington Electric Department ("BED").

Q. **What is the purpose of your testimony?**

A. My testimony will analyze the Vermont Gas System, Inc.'s ("VGS" or "Company") proposed firm transportation rate, FT-G; I will demonstrate why it is appropriate to develop separate local transportation rates for service at the transmission and distribution levels for both firm and interruptible customers; and

I will address why open access policies should be made applicable to VGS and its tariffs.

Q. **What is Burlington Electric Department's interest in this proceeding?**

A. Burlington Electric Department has essentially been denied access to the gas supply market by VGS's transportation pricing policies. BED contends here, as it did in Docket No. 6016, that VGS has priced its transport service so high that no one will find it economic to utilize this service. Notwithstanding the Public Service Board's finding in Docket No. 6016 that VGS's Interruptible-Transportation ("IT") Tariff was just and reasonable, no one has chosen to take service under that Tariff to date. The pricing of the proposed FT-G rate is likewise so high that it is unlikely any one will utilize this service either. The result is that VGS will remain the monopoly provider of bundled gas service in Vermont for the foreseeable future.

BED is a not-for-profit electric utility. It could be a large transportation customer on behalf of its generating plant, the Joseph C. McNeil Generating Station. This plant was designed primarily to burn wood, but it can also use either gas or distillate oil. If BED cannot receive gas at a price low enough to generate electricity, its choices are reduced to wood or oil. BED is a large enough customer so that it would be economic for it to purchase its own gas, if transportation were available at a reasonable rate. If gas transportation is priced higher than either marginal or embedded costs, there will be times when BED is

forced to use another more expensive fuel. This directly increases costs to both electric ratepayers and gas ratepayers. Also, if BED pays a gas transportation rate that is priced higher than cost, its electric ratepayers are providing a subsidy to an investor-owned gas utility. There is no economic or public policy rationale for this result.

Q. **Please explain how BED has been denied access to the gas supply market.**

A. The McNeil plant is located on and served off the VGS transmission system. If VGS offered a transportation rate that reflected only transmission system costs, BED could utilize that rate and have access to the Canadian gas transmission system that serves VGS. If VGS were connected to other interstate gas transmission systems, FERC's open access policies would clearly support such access.

Q. **How has VGS priced its service to McNeil in the past?**

A. A small amount of McNeil usage of gas, which is utilized for firing (start up) of the boilers, has been firm, but fuel for electric generation has been interruptible. The only real choice available has been interruptible sales service, since the IT rate, based on VGS's entire distribution and transmission system, is prohibitively priced. Early in the life of the unit, gas was priced so that it was often economic and was utilized extensively in the summer and warmer periods in the spring and fall. Under the initial contract BED received gas at a commodity charge adjusted by a pricing index. BED also paid a fixed monthly amount for 36 months that

began at $13,786.40 per month, which resulted in total payments of more than $500,000. It was and is BED's understanding that this payment was to repay VGS for the investment costs associated with extending the transmission line to McNeil and for other plant costs, which had an original cost to VGS of $125,399. Since 1993, however, interruptible gas has generally been priced by VGS equivalent to the cost of oil, and it has not been economic to utilize for generation. This was often the case even when the most economic alternative source of energy to gas has not been oil, but wood. VGS has thus not even consistently offered accurate "value of service" pricing to McNeil. As a result, McNeil has not often burned gas in recent years.

Q. What is the impact on McNeil of this pricing of gas and gas transportation?

A. Since McNeil has to pay more than competitive market prices to receive gas, its fuel cost and therefore dispatch price has been higher than for similar electric generators. For instance, under the proposed FT-G rate, a customer with a 50% load factor would pay about $1.90 per MCF transported, whereas the other gas transportation rates I have seen around New England range from $.60 to $1.00 per MCF. These inflated prices reduce the hours in which McNeil is dispatched to provide generation. This increases the cost to BED electric customers and is economically inefficient. The inability to acquire gas at market prices means that energy which could be produced by McNeil burning gas will be produced instead by McNeil burning wood or by other units in New England, which may be

burning oil. Since gas is environmentally preferable to the alternative fuels that are burned, VGS's gas pricing policy may be viewed as having a negative environmental impact.

Q. **Has the Company explained why it has filed only a single transportation rate, applicable to customers who take service at both distribution and transmission levels?**

A. The Company testifies that the operation of its "transmission and distribution facilities is highly integrated." It also referred to the Order in Docket No. 6016. However, the Procedural Order in Docket 6335 states that the question of "whether it is appropriate for VGS to offer a "transmission only" tariff is a subject of consideration in this docket.

Q. **Has the Company presented any reason for not considering a transmission level rate other than the "integrated" nature of the system?**

A. The Company also relies on its judgment that the only customers that are currently eligible to take service under FT-G are distribution level customers. This, however, is inaccurate, as other customers may take service under FT-G if they pay for any required system upgrades. These customers would clearly include the McNeil plant, which is a transmission level customer.

Q. **Why do you recommend both a transmission rate and a distribution rate for transportation service, when the Company has proposed a single Transportation rate?**

A. The transportation rate proposed by the Company is designed on the basis of customers who utilize the Company's distribution network. However, there are customers, such as BED, who are served directly off the Company's local transmission network, and who do not utilize the distribution system.

Q. **How is McNeil served directly from the local transmission system?**

A. The McNeil plant is served by a 3120 foot transmission line that connects directly to the 8" transmission line that "feeds" North Burlington Gate Station. Distribution mains typically operate at less than 100 psig, and distribution systems do not supply gas back to high pressure transmission systems.

Q. **Is this an adequate reason to establish a new rate class?**

A. Yes. Standard ratemaking theory holds that classes should be differentiated based on major cost causation characteristics. If those characteristics mean that cost causation is different between classes, the cost allocation process should reflect those differences. This is the same principle that the Company has applied in creating a transportation rate, reflecting that some customers will not require the Company to provide them with gas supply. The Company has also recognized cost causative characteristics in its proposal to establish new rate classes for firm

customers based on their characteristics rather than their end uses. Some customers do not make use of the distribution system. These customers could stop taking service and would not create any additional capacity on the distribution system. The converse of this situation is that if the distribution system were closed, VGS could still supply gas to McNeil. VGS did not install distribution mains to provide service to customers who take service directly from the local transmission system.

Distinguishing between customers who take service from the distribution and the local transmission system is similar to voltage or service level differentiation in electric cost of service studies. These rates reflect the fact that customers who take service from the primary distribution system do not use and should not pay for the secondary distribution system.

Q. Does the fact that the distribution and transmission systems are "integrated" change the fact that transmission level customers do not utilize the distribution system?

A. No. Clearly, the primary and secondary distribution systems of electric companies are also "integrated". Electricity flows from the primary to the secondary systems, and customers may be served off either the primary or the secondary systems. This has not prevented the development and approval of rates that require primary service customers to pay only for a share of the primary

service facilities, and not for secondary facilities that are utilized by lower voltage customers.

The Company has stated that demand on distribution lines can affect transmission capacity, and vice versa. This does not mean that a customer taking service off the transmission line makes use of the distribution system. If the transmission system has been sized to meet the firm load of the entire system, customers who take service off the transmission system should be able to utilize transportation capacity to the amount of their normal firm load without preventing the Company from serving distribution customers. If an interruptible customer served directly off the transmission system was allowed to take gas at a level that would reduce the Company's ability to serve firm customers on the distribution system, I would describe this as an error on the Company's part. The Company would have allowed the customer to use more of the transmission system than it was entitled to as an interruptible customer. It would not, however, mean that the customer had used the distribution system.

Q. **What would be the appropriate basis for a local transmission rate?**

A. A transmission level transportation rate should be lower than a distribution level transportation rate, because it should not be allocated any of the distribution system except for plant that it actually makes use of, such as meters. Thus the allocation of plant and expenses should exclude a number of costs that are appropriately allocated to distribution customers. I have estimated that a firm

transmission level rate should be priced at roughly 40% or less of the level of the distribution level rate for the same service.

Q. **Would it be unusual to find large customers not transporting their own gas when offered appropriately priced transportation rates?**

A. No. In other parts of the country, gas companies have truly opened access to the gas supply system, and customers have responded by going directly to the gas supply market. The U.S. Congress and the Federal Energy Regulatory Commission have documented the benefits of wellhead decontrol. However, because VGS has not unbundled its system and has priced its transportation services so high that it is not economic to utilize that service, VGS has failed to extend the benefits of wellhead decontrol to McNeil. Unless the Board intervenes and requires VGS to unbundle its transmission function from its distribution function, VGS will have effectively prevented all but one seller, itself, from reaching McNeil.

Q. **Would it also be appropriate to develop an interruptible transportation rate for transmission level customers?**

A. Yes it would. It is clear from the fact that there are no customers on the existing interruptible transportation rate that the rate has been priced above market prices, if not above the actual cost of service. This pricing leads to inefficient results, as customers who could economically purchase gas and transport it across Canada

are unable to get the gas delivered economically. I should note that today, one can purchase gas at the wellhead in Canada and purchase transportation of that gas to the U.S./Canada border. However, from that point to anywhere else in Vermont the bottle neck facilities are controlled by the Company. This problem is compounded in the case of McNeil. The rate is excessive not only because it is not based on marginal costs, but also because it is based on embedded costs of a portion of the Company's plant that does not in any way serve McNeil.

This pricing causes McNeil harm, as described earlier, but it also causes harm to the Company. McNeil would transport more gas than it currently purchases from the Company as interruptible sales if the service was truly cost based. It is most likely that this would provide VGS with greater margins than it currently receives from McNeil. This result would reduce electric costs in Vermont and would also probably increase the revenues above costs that would be contributed by McNeil that could go to benefit other gas ratepayers.

Q. **How should an interruptible transmission level transportation rate be developed?**

A. Such a rate should be based on a cost allocation study that reflects how interruptible customers use the system. The Company only allows interruptible sales customers to use gas when the system has adequate supplies and main capacity to accommodate the interruptible load. Interruptible transportation will be allowed only when the transmission and distribution system has adequate

capacity. Vermont Gas plans its gas supply to meet firm demand peak load, and allocation of the transmission and distribution system should reflect this fact. Next, all plant and expenses associated with distribution level delivery of gas should be excluded from the interruptible transportation rate to produce a similar rate for transmission level customers.

I prepared a cost-based interruptible transportation rate for transmission-only customers in Docket No. 6016, which is attached hereto as Exhibit BED-2. While this exhibit would need to be slightly modified to account for VGS's most recent revenue requirement filing, it generally sets forth a just and reasonable interruptible transportation rate for transmission-only customers like McNeil.

Q. **Do you have any other problems with the proposed transportation rate?**

A. The rate as proposed is very sensitive to customer load factor. The customer must commit to a Maximum Daily Transportation Quantity ("MDTQ") based on the customer's past maximum usage. Since the rate is very demand intensive, a customer with a 50% load factor would pay almost twice as much as a customer with a 90% load factor. This does not necessarily reflect cost causation, because the customer's peak might not even occur during VGS's peak hours or days. The rate could be improved by introducing more pricing flexibility, that would encourage customers to use less gas on the VGS peak rather than simply improving their computed load factor.

Q. Does this conclude your testimony?

A. Yes, it does.

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Exhibit 3

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER COMPANY	)	
	)	Docket No. 01-0432
Proposed revisions to delivery services tariff	)	
sheets and other sheets	)	

REBUTTAL TESTIMONY

SUBMITTED BY

LEE SMITH

ON BEHALF OF

PEOPLE OF THE STATE OF ILLINOIS

AND THE

CITIZENS UTILITY BOARD

NOVEMBER 6, 2001

REBUTTAL TESTIMONY OF LEE SMITH

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lee Smith. I work for La Capra Associates, 333 Washington St., Boston, Massachusetts.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A, Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I am responding to the rebuttal testimonies of Ms. Althoff and Mr. Jones of Illinois Power Company. I will contrast the rate design positions of the Company with that of the People of the State of Illinois and the Illinois Citizens Utilities Board.

Q. DID MS. ALTHOFF RESPOND TO YOUR POSITION ON THE ALLOCATION OF THE COMPANY'S MISCELLANEOUS REVENUES?

A. No. It is not clear that Ms. Althoff understood my position. Her basic response seems to be that she is not aware of any textbook directing that revenues should be allocated in accordance with costs. She continues to assign revenues to classes according to who paid those revenues, with no reference to underlying costs

Q. PLEASE RESTATE YOUR OWN POSITION.

A. It is common practice to allocate costs to customer classes, then to set the class revenue requirements equal to the allocated costs. However, we do not have specific rate classes for the services that give rise to miscellaneous revenues. If we are trying to create rates that reflect cost causation, then most "Miscellaneous Revenues" should be allocated according to the costs that are incurred in order to produce the revenues. Most miscellaneous revenues represent services provided by the utility that have underlying costs which are included in the cost of service in various accounts. For instance, equipment and property rental revenues are received for use of utility plant. Customer

classes all share in the cost of this rented plant, and the revenues should be allocated in the same way that the costs of the plant are reflected in the cost of service. Most other utility provided services that produce revenues, such as reconnects, establishing temporary service connections, and service activation, require that activities be performed by utility distribution personnel. These revenues should be allocated in the same manner that the cost of the personnel performing the service was allocated.

Exceptions to the above treatment include revenues which may not have underlying costs. For instance, forfeited discounts reflect customers not paying bills on time, and it is appropriate that they be credited to customers in proportion to how they were booked.

Q. HAS THE COMPANY PROVIDED ANY INFORMATION THAT WOULD JUSTIFY A DIFFERENT ALLOCATION OF MISCELLANEOUS REVENUES?

A. No.

Q. HAS THE COMPANY CHANGED ITS POSITION REGARDING THE ALLOCATION OF SECONDARY DISTRIBUTION PLANT ACCOUNTS?

A. Yes. Ms. Althoff indicates that "additional statistical information ....disclosed that demand metered general use customers up to 200 kW can have service lines that connect to secondary distribution lines." (IP Exhibit 8.10. p.8, lines 154-155.) This is the position that I argued in my direct testimony. The Company has developed a new allocator for these costs that reflects the fact that most Rate Class 3 customers do make use of secondary facilities. The Company's revised allocation of secondary plant to Rate Class 3 is 25.6%, compared to its original allocation of 0% to this class. This allocates slightly less secondary facilities to Rate Class 3 than the original Primary Service allocator that I utilized in Schedule LS-1 (25.6% compared to 35.1%). I will accept the Company's revision on this issue.

Q. HAS THE COMPANY CHANGED ITS POSITION ON RATE DESIGN?

A. Yes. Mr. Jones has agreed that the Facilities Charges for residential customers taking delivery service should be set at the same levels as the Facilities Charges that will

be in effect on May 1, 2002, after the rate reduction of 5%. I recommend adoption of this proposal.

Q. HAS MR. JONES MODIFIED ANY OF HIS OTHER POSITIONS ON RATE DESIGN?

A. No. In his rebuttal testimony, Mr. Jones accepts that the cost of local distribution facilities does increase with load, but he does not change his position on rate design as a result. He still wants to collect the total cost of local distribution facilities from each customer, as if these costs were collected through a customer charge. He introduces a new exhibit, IP Exhibit 6.12, that he claims shows that secondary distribution costs increase only very slightly as load increases. This exhibit is evidently intended as an argument against volumetric delivery service charges. This very hypothetical exhibit compares the costs of two unique residential circuits, one of which is supposed to serve 6 customers who use an average of 300 kwh/month, and the other which is supposed to serve 6 customers who use an average of 3000 kwh/month. This exhibit purports to show that although secondary facility costs vary with size, they do not increase at nearly the same rate as load, so the cost per kwh of serving a large residential customer is much less than the cost per kwh of serving a small residential customer. For instance, in this exhibit load increases 10 times while costs increase only about two times.

Q. WHAT DOES THIS EXHIBIT ACTUALLY DEMONSTRATE REGARDING THE COST PER KWH OF SECONDARY DISTRIBUTION FACILITIES?

A. At most, it shows that under these particular circumstances, cost per kwh decreases significantly as customers get larger. This exhibit does not prove that this is the case all the time, or that per kwh costs generally decrease significantly with size of customers. IP's results have been determined by two particular hypothetical situations, and there are a number of ways in which these hypothetical installations do not appear typical. According to the response to CUB Data Request 6.11, this example assumes exactly the same plant layout for both small and large customers, with the same distances between houses and the same length services. Both examples show 6 customers in 6 identically shaped lots, served off one 125 foot length of conductor. However, if larger

customers were more widely spaced, they would need a longer length conductor and more poles. The two customer groups also have the same load shape, so that the customers whose energy use is 10 times that of the small customers also use exactly 10 times the peak load. This again appears to be atypical; a customer using 3000 kwh is likely to have air conditioning or electric heating, and is thus likely to have higher peak relative to energy use. The particular costs cited show higher labor and overhead cost for the smaller transformer than for the larger transformer, which is probably not typical, given that the steps to install transformers are similar, although there may be less effort in connecting the small transformer, which is serving single phase customers.

Another theoretical problem with this "analysis" is that it does not indicate at what size a customer needs larger facilities. The example shows that a more expensive conductor and transformer must be installed for the 6 customers who used 3000 kwh per month. However, this same more expensive plant may be needed for 6 customers who used only 1,000 per month. This may happen often because these pieces of equipment do not come in infinite size variations. Once load gets too large for a 10kVA transformer, the next size is probably quite a bit larger. In the Company's hypothetical, if the load that was divided into the cost was 1,000/month per customer rather than 3,000/month per customer, the difference between the cost per kwh in the two customers would be smaller.

I would expect that we could find other segments of the secondary distribution system that would produce very different results. For instance, we might find a circuit serving smaller customers that enabled more customers to share a transformer, and a circuit serving larger customers who were farther apart and thus needed a longer conductor. The first would show greater sales, which would reduce the cost per kwh of these facilities. The second distribution segment would show higher total costs and thus would increase the cost per kwh. These are only two of the variables that could change and cause very different results.

Q. DOES THIS EXHIBIT SUPPORT THE CONCEPT THAT THE COST PER KWH OF SECONDARY DISTRIBUTION FACILITIES DECREASES SO MUCH AS CUSTOMERS GET LARGER THAT SECONDARY DISTRIBUTION FACILITIES COSTS SHOULD BE CHARGED ON A PER CUSTOMER BASIS?

A. No. There is no evidence that this exhibit represents typical distribution facilities.

Q. HAS MR. JONES AGREED WITH YOUR PROPOSAL TO SET THE RATE BLOCK DIFFERENTIAL 0.8 CENTS/KWH?

A. No. Mr. Jones argues that the "winter price differential" should be set at the winter block difference of 1.76 cents per kwh.

Q. PLEASE DISCUSS THE WINTER RATE BLOCK DIFFERENTIAL.

A. The current bundled rate has a higher differential, 1.76 cents, between blocks in the winter, than in the summer. This differential was originally driven by both distribution and generation costs. I do not recommend utilizing this differential in a separate winter delivery service rate.

First, this differential is higher than a cost-based differential, even if we accepted that it should recover secondary distribution costs. It is higher than the differential that the Company had originally claimed was justified by the cost of the secondary distribution system. The Company has since reduced its allocation of secondary distribution plant to the residential class, so its original differential is no longer supported.

Second, this approach would charge each customer as if he or she was responsible for the average level of secondary distribution costs. In my direct testimony I discussed the fact that secondary distribution costs vary with the size of the customer, as we would expect of capacity costs. Mr. Jones' rebuttal testimony accepts that secondary distribution costs do vary somewhat with customer size. If we charge each customer for the average amount of facilities, small customers will pay too much. Thus, the Company has not justified this size differential for average sized customers, and even if it were justified for

average sized customers, this amount of differential will charge too much to low use customers.

Q. IS THIS THE REASON YOU ADVOCATE USING THE SUMMER DIFFERENTIAL IN BOTH SUMMER AND WINTER DELIVERY SERVICE RATES?

A. Yes. While some amount of block differential might be justified on the basis of costs, the Company has not justified the differential that it has proposed. If we use the bundled rate summer differential, customers will see the identical rate structure between the bundled rate and the delivery service rate in the summer. The residential delivery service rate will also be relatively simple, with the same differential in both seasons.

Q. HAVE YOU MODIFIED YOUR COST OF SERVICE?

A. Yes. I have reflected both Mr. Effron's rebuttal testimony and the Company's revised secondary distribution allocator, by modifying the Cost of Service Study (COSS) presented by the Company in its rebuttal testimony. The summary of this COSS is contained in Schedule LS-4. In addition, I have developed the residential rate revenue requirement from this in Schedule LS-5. I would recommend this revenue requirement as the basis for designing rates.

Q. HAVE YOU DESIGNED A RESIDENTIAL DELIVERY SERVICE RATE CONSISTENT WITH YOUR TESTIMONY?

A. Yes. Using the Company's revised billing determinants. I have developed a rate that contains a 0.8 cent differential between 300 kwhs per month and all other usage. This is shown in Schedule LS-6.

Q. WHAT RATES DO YOU PROPOSE?

A. I recommend a residential monthly facilities charge of $5.95, $7.96 and $16.00 for multi-family, single phase and three phase service respectively, and a declining block rate of $0.0260 per kwh for the first 300 kwh and $0.0180 for usage over 300 kwh.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit 1

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER COMPANY	)	
	)	Docket No. 01-0432
Proposed revisions to delivery services tariff	)	
sheets and other sheets	)	

DIRECT TESTIMONY

SUBMITTED BY

LEE SMITH

ON BEHALF OF

PEOPLE OF THE STATE OF ILLINOIS

CITIZENS UTILITY BOARD

SEPTEMBER 12, 2001

I. INTRODUCTION

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lee Smith. I work for La Capra Associates, 333 Washington St., Boston, Massachusetts.

Q. WHAT IS YOUR OCCUPATIONAL EXPERIENCE?

A. I am a Senior Economist and Managing Consultant at La Capra Associates. I have been with this energy planning and regulatory economics firm for 17 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level.

Q. WHAT IS YOUR EXPERIENCE IN RATE DESIGN AND COST ALLOCATION?

A. Since leaving the Massachusetts DPU, I have performed cost studies and prepared rate design for over twenty utilities in more than twelve states. I have advised Commissions and consumer advocates on issues related to electric and gas rates and electric restructuring. My resume is attached.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I have a bachelor's degree with honors in International Relations and Economics from Brown University. I have completed all requirements for the Ph.D. except the dissertation from Tufts University.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Illinois Citizens Utility Board and the People of the State of Illinois.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will comment on the Company's cost allocations and on its proposed changes in rate design, and provide the allocated results of the changes produced by Mr. Effron.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I have found that the Company has overstated the cost of service of the residential class, as a result of several allocations which are not appropriate. The Company has developed rates using billing determinants which are too low, which produce rates that are higher than they should be. In addition, Illinois Power's proposed residential rate design is not justified. Specifically, the Company's proposal to increase the difference between declining block rates conflicts with a number of rate design principles and should not be adopted.

I recommend that the customer charge for residential delivery service mirror the customer charge for residential bundled rates, and that the differential between the first and the second block charge found in bundled rates remain the same in the delivery service rates. This will allow customers to more easily compare bundled and unbundled rates, and prevent any unreasonable or unjustified price disparities in the event a customer chooses unbundled service. I further recommend that those block rates should be set according to

the revenue requirement recommended by Mr. Effron and the allocations recommended by myself.

II. ALLOCATED COST OF SERVICE STUDY

Q. PLEASE DESCRIBE THE COMPANY'S ALLOCATED COST OF SERVICE STUDY.

A. The Company has allocated its claimed delivery service cost of service to the rate classes for whom it is proposing delivery service rates. The fundamental Delivery Service Tariff will include four rate groups, for residential (SC2 and 3), non metered general service customers (SC 13), demand metered general service customers (Rate Class 3), and small non-demand metered general service customers (Rate Class 2A). The Company allocated costs to its existing rate classes, then combined classes into only the four categories for Delivery Service rates. The categories of costs allocated include subtransmission, distribution, customer costs, and administrative and general costs. Much distribution plant is allocated on the basis of non-coincident peak ("NCP") allocators, which are intended to measure class peak usage as a proportion of the sum of peak usage of all classes. These peaks generally occur at different times, unlike coincident peaks, which reflect what each class uses at the time of the system peak. The theory behind allocation on the basis of non-coincident peaks is that distribution plant must be constructed to meet the peak load of every class, whenever it occurs. Most of the other distribution plant is allocated on the basis of the numbers of customer in each class, weighted by cost differences among the type of plant serving different customer classes.

Q. HAVE YOU FOUND ANY PROBLEMS WITH THE COMPANY'S CLASS

ALLOCATED COST OF SERVICE STUDY ("COSS")?

A. Yes. The Company allocates no secondary distribution costs to Rate Class 3, which contains most of the commercial and industrial (general service) customers. Since most Rate Class 3 customers take service at a secondary voltage, as a whole, they would be expected to utilize secondary service facilities and therefore should be allocated a portion of the cost of these facilities.

In the typical configuration of electric systems, serving both residential, and small and medium sized general service customers, the primary system delivers power to line transformers which step down the power to secondary voltage. All customers other than very large ones are served either from a secondary service line from the line transformer or a secondary distribution line. The configuration of secondary service to general service customers taking power at secondary voltage will be similar to that of residential customers. Thus, normal treatment is to allocate secondary distribution plant to all customers who receive service at secondary voltages.

Q. IS THERE EVIDENCE IN THIS CASE THAT SUPPORTS YOUR ARGUMENT THAT CLASS 3 CUSTOMERS TAKING SERVICE AT DISTRIBUTION LEVEL USE THE DISTRIBUTION SYSTEM IN A MANNER SIMILAR TO RESIDENTIAL AND OTHER SECONDARY SERVICE CUSTOMERS?

A. Yes. Mr. Jones testifies that Demand Metered General Service customers under 200 kW "typically receive service at low voltage" (line 266, p.14). According to the Company's Electric Service Marginal Cost, in the response to IIEC Data Request 2.22 D, p.6, the

service cost for overhead distribution customers for much of current bundled rate 11 (now in delivery service Rate Class 3, for demand-metered general service customers) is the same as residential and the non-demand metered general service customers. Again, this suggests that the use of the secondary system by these rate 11 customers is similar to the use of the system by the residential class.

Q. WHAT IS THE EFFECT OF THIS ON RATE CLASS REVENUE REQUIREMENTS?

A. Other classes, specifically the residential class, the unmetered general service class, and class 2A, will be allocated more costs because Rate Class 3 is not paying any share of secondary distribution plant.

Q. HOW WOULD YOU ADJUST THE ALLOCATION OF SECONDARY DISTRIBUTION FACILITIES?

A. I would allocate secondary distribution facilities to all customers who take service at the secondary level, including most Rate Class 3 customers. According to the Company's response to IIEC Data Request 2.22-D, approximately 31,000 Class 3 customers receive secondary level service. Since these customers receive secondary level service, they should be allocated some of the costs of secondary poles (account 364), secondary distribution lines (account 365), secondary underground conduit (account 366), and secondary underground conductors and devices (account 367). The COSS however allocates 0% of these accounts to Rate Class 3.

The best allocator for these secondary accounts would be the non-coincident peak of all

customers taking secondary service. About 5% of the non-coincident peak load in Rate Class 3 takes service at higher voltage levels. The best allocator would therefore be very close to the non-coincident peak allocator calculated by the Company which does include all classes, labeled DEMPRI. Since the cost of service study does not contain the correct non-coincident peak allocator, we have utilized DEMPRI to allocate these secondary distribution plant accounts.

Q. SHOULD ANY OTHER COST ALLOCATIONS BE MODIFIED?

A. Yes, but these will occur automatically as the COSS model is run. For instance, a number of expenses are allocated based on how plant is allocated. Thus as less secondary line is allocated to residential customers, related expenses will also be reallocated.

Q. WOULD YOU PLEASE DESCRIBE THE COSTS OF PROVIDING THE SERVICES THAT GIVE RISE TO OTHER OPERATING REVENUES?

A. The cost of service study does not identify the cost of providing the miscellaneous services that give rise to "other" revenues.

When asked whether the Company allocated miscellaneous revenues on the same basis as the costs associated with the services that produced these revenues, the Company states[1] that costs expended in "handling miscellaneous revenues" are spread across various accounts, and that allocating them according to "where the costs are recorded" is not appropriate. It is not clear what the Company is referring to in the response above. What

[1] Response to Data Request CUB 2.10

matters is not the cost of "handling" revenues, but the cost of providing the underlying service.

The Company receives miscellaneous revenues primarily as a result of providing services. These services are provided by Company employees and/or by Company equipment. For instance, distribution personnel would reconnect customers along with their other duties, and the reconnection revenues would be booked under other operating revenues. It would appear that most of the reconnection costs would be booked under distribution maintenance expense or distribution plant (for the category titled equipment).

Q. HAS THE COMPANY ALLOCATED OTHER OPERATING REVENUES CORRECTLY?

A. No. Since the COSS allocates all costs to rate classes, revenues are usually allocated in the same manner as the allocation of the underlying costs.

The largest amount of Other Operating revenues is in the category of Miscellaneous revenues. These include forfeited discounts, equipment, reconnection charges, temporary services, miscellaneous, and water heater rentals. The revenues that result from these services should be allocated in the same manner as the expense of the employees or the underlying equipment. For instance, if revenue is produced by one activity of meter readers, the revenue should be allocated in the same manner that the meter readers expense is allocated. Customers should receive the benefits (i.e. the revenues) equivalent to the costs that underlie the services that result in the revenue.

Under the Company's approach, one class could be allocated most or even all of an expense that allowed the service to be provided, and yet could receive credit for none of the revenues created by these services.

Q. HOW HAVE YOU ALLOCATED THESE REVENUES?

A. I expect that equipment revenue, which represents the majority of miscellaneous revenues, includes payments by customers paying for maintenance of installations on their premises, which will sometimes include replacement plant. I have allocated all of the miscellaneous revenues on the same basis as the Distribution Operating Labor expense. Although residential customers pay a small proportion of miscellaneous revenues, and therefore in the Company's COSS receive a small allocation of these revenues, they have been allocated a much larger share of the underlying expenses. Residential customers essentially "paid for" those miscellaneous revenues through IP's allocation of costs. My change to the COSS recognizes this.

Q. WHAT IS THE RESULT OF THIS REALLOCATION OF SECONDARY DISTRIBUTION COSTS AND OTHER REVENUES?

A. The allocation changes described above, to secondary distribution plant and to miscellaneous revenues, were made utilizing the Company's COSS model. The residential class revenue requirement decreases as the rate base decreases by $27 million and Total Operating Expenses decrease by about $4 million. This is illustrated in Schedule LS-1, the summary page of my revision of the Company's COSS.

III. BILLING DETERMINANTS

Q. WHAT IS THE PROBLEM WITH THE BILLING DETERMINANTS USED BY THE COMPANY IN CALCULATING RATES?

A. There are several problems. First, as Mr. Effron testifies, they have not normalized billing determinants to reflect even the number of customers on the system at the end of the test year. Second, the Company is making proforma adjustments to costs without reflecting equivalent adjustments to billing determinants. It would be appropriate to reflect the same time period in billing determinants that is reflected in cost adjustments. Third, the Company "discovered the need to revise billing determinants", according to an Email original sent to Greg Gudeman of Dynegy on 8/31/01, evidently related to weather normalization and selection of the wrong demand. The Company should be ordered to normalize billing determinants to the end of the test year, utilize correct weather normalized billing determinants, and then project these normalized billing determinants to a period consistent with any proforma plant adjustments allowed. This will result in slightly lower rates. Failure to make these adjustments will mean the Company will overcollect its revenue requirement.

IV. RESIDENTIAL RATE DESIGN

Q. WHAT IS THE COMPANY PROPOSING FOR A RESIDENTIAL RATE DESIGN?

A. The Company proposes that residential rates be differentiated by single and three-phase service for single family residences, and for multi-family service. The proposed

customer charges (called facilities charges by the Company) are $8.43 for single phase, and $13.62 for three phase service and $7.30 for multi-family service.

Illinois Power's proposed delivery charges for all residential customers include $.03438 for the 1st 300 kwh per month, and $.02176 per kwh for additional kwhs. In other words, this is a declining block rate, with the tailblock $.01262 less than the first block.

Q. HOW DO THESE CHARGES COMPARE TO THE EXISTING BUNDLED RATE DESIGN?

A. Current residential customer charges for bundled service are $8.46 for single phase and $17.00 for three phase service, and $6.33 for multi-family. Current bundled rates contain customer charges which are essentially the same for single phase customers, who are in the majority of residential customers, higher for three phase customers, and lower for multifamily customers. Current bundled rates also have two blocks, with the same block sizes, but the rate reduction from the first to the second block is only $.0085, or $ .00412 less than the Company's proposed differential.

Q. IS IT CLEAR WHY THE COMPANY HAS PROPOSED THESE CHANGES IN CUSTOMER CHARGES?

A. No. The Company has explained neither the rationale nor the result on bill impacts or customer behavior of changing these charges.

Q. WHAT IS THE RESULT OF THE PROPOSED RESIDENTIAL RATE DESIGN?

A. While decreasing customer charges is often a desirable rate design change, charging different delivery service customer charges from bundled service customer charges is not desirable, since all of the costs to be recovered in customer charges are related to distribution service. It means that customers may either pay more or less under delivery service rates than under bundled service. It would also appear to affect customers bills differentially depending on the size of the bills. For instance, the increase in the DST multifamily customer charge may cause a number of small customers' bills to increase if they leave bundled service, and if their generation costs are the same as those included in bundled service.

Increasing the steepness of the block rate means that smaller use customers pay more of the class revenue requirement. If all customers pay the same for generation, smaller customers will receive a higher percentage increase than other customers. Also, the rates provide less incentive to conserve usage, since it costs less for usage over 300 kwh than flat rates or even than if the existing differential were retained.

Q. WHAT IS THE COMPANY'S RATIONALE FOR THE PROPOSED DECLINING BLOCK DISTRIBUTION CHARGE?

A. Mr. Jones states that the Company both "considered the requirement in the Customer Choice Law that delivery service rates be cost-based" and also considered the requirement that rates should take into account voltage level differences. Specifically, the Company's rate design is intended to recover the costs of secondary lines and transformers through the first block energy charge. Since 80% of customers consume

more than 300 kwhs per month, presumably 80% of customers will pay for the local secondary distribution costs. Collecting these costs through the first block charge is almost the same as collecting them through a customer charge, which Mr. Jones also claims is appropriate.

Q. DO EITHER OF THESE PROVISIONS REQUIRE THE RATE DESIGN PROPOSED BY THE COMPANY?

A. No they do not. The declining block energy charges result from the Company trying to recover the cost of local secondary facilities through the first block charge. The Company implies that certain facilities costs must or should be collected through a particular rate component. The law, however, does not state or even imply a particular formulaic approach. Once the Commission finds that it is appropriate that the Company collect a certain amount of revenue, rates should be designed to collect this revenue requirement. There is no compelling reason why a particular type of cost must be collected in a certain charge.

Also, according to Mr. Jones, this pricing better matches how local low voltage costs are incurred. Again, this provision does not require the rate design proposed by the Company. In order to meet the requirement that rates reflect voltage level differences, costs should be differentiated by voltage level where possible and allocated according to how they are used. If there are customers served at different voltage levels within a rate class, rate design can differentiate between them. The higher first block charge does not contribute to voltage level differentiation.

Q. DOES THE COMPANY'S RESIDENTIAL RATE PROPOSAL ADEQUATELY CONSIDER BILL IMPACTS?

A. No. The Company's rate design creates uneven bill impacts. If residential customers can purchase generation at the credit included in the bundled rate, this rate design will result in smaller customers receiving significant rates increases if they choose alternative suppliers, while large customers receive either lower increases or rate decreases.

Q. HOW DO YOU RECOMMEND THAT THE RESIDENTIAL RATES BE DESIGNED?

A. There are a number of principles that are normally considered in rate design. Rates should be fair and equitable; they should allow for the collection of legitimate costs; they should be relatively simple, which facilitates customer understanding of the rates; rates should assist with or at least not conflict with social goals set by the Commission, such as making electric service available to all customers (universal service) and/or encouraging conservation; rates should provide price signals that encourage efficient use of the product, and there should be concern for rate continuity. All of these principles should be considered, although compromises between principles may be necessary.

With regard to delivery service rates, these principles suggest a number of things. Rate continuity suggests that changes should be gradual, so that changes take into consideration the impact that they will have on customer bills. It would contribute to simplicity and customer understanding to change rates as little as possible from the existing bundled rates, particularly during this period of change. In this case, customers

are facing many changes in the way electricity is sold and delivered, which would seem to make rate continuity an important consideration.

With regard to equity and cost collection, the starting point for rate design should be a proper identification of delivery service costs; next, these costs should be allocated across rate classes. The principal basis for cost allocation should be cost incurrence; however, there may be other considerations, particularly where the cost incurrence cannot be clearly identified.

To provide proper price signals, rates must at a minimum communicate the marginal cost of increasing usage. In other words, if it costs two cents per kwh to deliver additional energy, the usage charge should be at least two cents. This is discussed further later in the testimony.

Equitable rates for distribution services will emphasize usage charges. Most distribution costs are a function of the size of load, particularly of peak customer load. For instance, larger customers require greater expenditure on transformers, either because they use larger transformers or because they require individual transformers rather than sharing them. Among residential customers, larger customers tend to be on larger lots, and will usually require more length of line and more poles than smaller customers. All of these considerations support delivery service rates based on usage so that bills increase as usage increases. Providing signals for conservation is also enhanced by usage sensitive rates.

Q. THE COMPANY ARGUES THAT CERTAIN DISTRIBUTION SYSTEM COST COMPONENTS SHOULD BE COLLECTED IN NONUSAGE SENSITIVE CHARGES. DO YOU AGREE?

A. No. Although customer and meter costs are driven by the number of customers, this does not require that monthly customer or facilities charges be set to collect these particular costs. There is even less rationale to collect distribution system costs (other than customer-related costs) in customer charges than there is to collect customer-related costs in this manner. Attempting to collect particular subsets of embedded costs in any particular manner may well conflict with fundamental rate design principles.

A specific example can illustrate why insisting on setting the customer charge according to embedded cost of service results may produce inappropriate price signals. I do not dispute the proposition that the number of meters and services installed is driven almost entirely by the number of customers, weighted by the cost of meters and services. Suppose that the embedded cost of meters and services is $10 per month, and all other embedded costs distribution costs only average $.04/kwh. To deliver an additional kwh costs the Company $.05/kwh. If customer charges were set according to the embedded costs, the remaining distribution charge would be less than marginal distribution costs. The volumetric distribution rate would encourage customers to use (actually, to have delivered) additional energy that they valued at only $.04, energy which it cost the Company $.05 to deliver.

Q. ARE THE PROPOSED RATE CHANGES CONSISTENT WITH PROVIDING EASY ACCESS TO ALL CUSTOMERS, OR THE CONCEPT OF UNIVERSAL SERVICE?

A. No. One underlying principle of electric rate design is the idea that electricity is a necessary public good that should be reasonably available to all residential customers. The higher the customer charge and the higher the first block charge, the less affordable electric service is to customers, particularly to small customers. The higher customer charge for multifamily residences and the steeper declining block charges proposed by Illinois Power will create a negative impact on small customers.

The Company computed the difference between bills based on a flat delivery service charge and the proposed delivery service charge. Large customers would pay about 8% more under flat rates, while customers under 850/kwhs per month usage would pay less under flat rates. This is indicative of the fact that increasing the rate differential between the first block and the tailblock results in larger customers paying less and smaller customers paying more as a result of increasing the differential.

Q. WHAT TYPE OF PRICE SIGNALS DO DECLINING BLOCK RATES PROVIDE?

A. The lower the charge for additional usage, the less incentive customers have to conserve energy. The most crucial element of price signal in a charge is that it reflects the incremental cost of additional usage. However, to the extent that there are societal (or external costs) of both production and delivery that are not reflected in monetized costs, there is rationale for incremental rates to be set higher than incremental costs.

It has become evident in California and other places that additional usage at peak times causes significant increases in power costs and significant stress on transmission and distribution systems. This stress increases maintenance costs and requires investment in plant. These impacts have not yet been felt in Illinois because of the existence of rate caps, but they will be felt in the future. Rates need to communicate to customers that additional usage will probably increase average costs. Declining block rates communicate the opposite message.

Q. YOU HAVE INDICATED ABOVE THAT EMBEDDED COST INCURRENCE IS NOT NECESSARILY THE BEST BASIS FOR SPECIFIC RATE CHARGES. IN ADDITION TO THIS PROBLEM, HAS THE COMPANY ESTABLISHED THAT ITS PROPOSED RATE DESIGN APPROPRIATELY REFLECTS COST INCURRENCE?

A. No. The Company has overstated the local low voltage costs that must be incurred to serve customers. The amount of plant that must be installed to provide power to customers is the minimum amount that could be built. However, the company does not build the minimum amount. Utilities install plant that is designed to meet demands well above minimum and to comport with a variety of other requirements. Thus, utilities often do not even purchase the minimum size. They utilize larger and more expensive equipment because customers are likely to have certain peak loads, and if the equipment is not sized to meet these loads, the system will not be reliable. Even if the Company knew that a particular location would use very little energy, it would build distribution that would provide for more typical energy usage, both because those would be the size transformers and conductors that were stocked and because usage could increase. In

other words, usage and reliability are cost drivers for distribution plant. The Company recognizes this in its allocation of distribution plant to rate classes on the basis of non-coincident peak usage, but there is a mismatch between this allocation and their rate design. By attempting to recover secondary distribution costs entirely through the first block charge, the rate design essentially allocates these costs among customers on the residential rate on the number of customers. It treats the full cost of secondary distribution, costs that are allocated in the COSS on peak usage, as if it were a customer cost.

Q. IF IT WERE APPROPRIATE TO CHARGE EACH CUSTOMER FOR THE MINIMUM COST OF PROVIDING SECONDARY SERVICE TO THEIR FACILITIES, WOULD THE COMPANY'S COMPUTATION BE CORRECT?

A. No. Even if it were appropriate to allocate a certain amount of secondary distribution plant to each customer, which it is not, the Company's approach would allocate too much to each customer. Its approach implies that it is necessary to incur the average cost of lines and transformers for every customer. This is not correct. Mr. Jones apparently wants to collect the average cost of local secondary facilities (lines and transformers) from every residential and small general service customer. Depending on the location and size of the customer, the cost of secondary lines and transformers varies between customers. A 10 kVA transformer can serve up to 2 customers. The average is 1.2 customers per transformer. Obviously some customers are utilizing only one-half of a transformer, yet if their facilities charge (or first block charge) reflects the average, they are paying for .83 transformers. This is even more true with regard to 25kVA

transformers, where the average served is 3.1 but the transformer can serve up to 6 customers. If every customer pays the average, some customers, particularly smaller customers, will pay for more than the cost incurred in providing power to them.

Q. WHAT DO YOU RECOMMEND FOR THE RESIDENTIAL RATE DESIGN?

A. I recommend that secondary distribution costs, which are driven by usage, should not be recovered in the first block charge, which is equivalent to recovering these costs in the customers charge. Also, I recommend that rate design, that is the customer charge and the price differential between the block rates, should be the same in the delivery service rate and the bundled rates. Finally, a reduction in the class revenue target will result in lower average per kwh charges than proposed by Illinois Power.

V. IMPACT OF COST OF SERVICE CORRECTIONS

Q. HAVE YOU ESTIMATED THE IMPACT ON CLASS REVENUE REQUIREMENTS OF MR. EFFRON'S RECOMMENDED CHANGES TO THE COST OF SERVICE?

A. Yes. I have reduced expenses and rate base following Mr. Effron's recommendations. In most cases, Mr. Effron indicates in what account the costs reside. In several instances, it was necessary to allocate his recommended reduction between several accounts. The reduction to distribution, both for depreciation expense and for plant, was allocated among accounts 361 to 368 according to the total amount of plant in these accounts in the Company's filed cost of service study. The reduction to general plant was likewise allocated among accounts 390 to 392. Since each of these accounts are allocated by the

same allocator, this last assumption does not affect the results in any way. The increase to accumulated depreciation was spread among all distribution plant accounts. I have relied on the COS model to calculate income taxes, so the total Company results are not identical to those produced by Mr. Effron. However, this COS should be very close to final results. I would recommend that the Company make these modification to reflect costs by account more accurately.

Q. WHAT ARE THE RESULTS OF THESE CHANGES?

A. The summary page of the COSS with the 4 rate groups, resulted from revising the Company's COSS to reflect my allocation changes and Mr. Effron's recommendations, is attached as Schedule LS-2. The Company's COSS model summary page does not actually show the total revenue requirement, but it does show the changes in separate cost components. Total operating and maintenance expenses allocated to the residential class decrease by $15.5 million, while depreciation and amortization expenses decrease by $4 million. Rate base allocated to the residential class decreases by $88.8 million. I have calculated that the return based on the rate of return utilized by Mr. Effron decreases by $11.7 million. The Company's COSS model does not show the reduction in income tax that should result from this reduction in income, either for the total company or for the residential class. I have estimated that income tax would decrease proportional to the decrease in return. The final result, shown in Schedule LS-3, is that the residential class revenue requirement declines by $35.2 million. The revenue requirements of all other classes also decrease. I recommend that rates be designed in the manner I have recommended, using appropriate billing determinants, to collect these revenue

requirements.

Q. HAVE YOU DETERMINED WHAT THE RESIDENTIAL RATES SHOULD BE?

A. No. As discussed earlier, I recommend that customer charges should mirror the bundled rate. I cannot determine my recommended per kwh charges because Illinois Power has not provided the correct billing determinants. I reserve the right to address this issue in rebuttal testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX E

GEORGE R. McCLUSKEY

LA CAPRA ASSOCIATES
Senior Consultant

George McCluskey is a ratemaking and planning specialist with over 20 years experience in utility economics. Since joining La Capra Associates in 1999, Mr. McCluskey has provided advise to several clients on a variety of restructuring, cost of service, merger and asset valuation issues. Previously, Mr. McCluskey directed the electric utility restructuring division of the New Hampshire Public Utilities Commission ("NHPUC."). Before that, Mr. McCluskey was manager of least cost planning, directing and supervising the review and implementation of electric and gas utility least cost plans and demand-side management programs. Mr. McCluskey has testified before the NHPUC in numerous electric and gas rate proceedings on cost of service analysis, rate design, power supply portfolio planning, and the integration of demand and supply-side resources. Mr. McCluskey has also testified before the FERC on prudence and stranded cost issues related to requirements power contracts.

RELEVANT EXPERIENCE

- Project manager for case before the Public Utility Commission of Texas requiring expert testimony on unbundled cost of service, cost allocation and rate design for three restructured transmission and distribution utilities.
- Directed the NHPUC's investigation into the application of marginal cost principles to gas utility ratemaking. Also prepared and presented expert testimony on behalf of NHPUC Staff that addressed all areas of disagreement including the methodology for calculating production-related marginal costs and the determination of class revenue requirements.
- Provided advice on pricing policy issues to electric distribution companies in England and Wales. This work involved translating the cost messages contained in the Central Electricity Generating Board's marginal cost based wholesale tariff into retail tariff messages for small and large consumers.
- Participated in the economic evaluation of power contracts entered into by the California Department of Water Resources valued at about $43 billion over ten years. This work was conducted on behalf of the Bureau of State Audits.
- Prepared and presented direct and supplemental testimony in a proceeding to establish the NHPUC's policy on the unbundling of firm and interruptible gas services. Also presented testimony on illustrative gas transportation rates for commercial and industrial customers.
- Advised the General Staff of the Arkansas Public Service Commission regarding Entergy Arkansas Inc.'s application to transfer ownership and control of transmission assets to an RTO. Includes cost-benefit analysis of the proposal to

create a Transco and the retail rate implications of transferring transmission assets to a FERC jurisdictional utility.

- Directed the preparation of the NHPUC 's plan to restructure New Hampshire's electric utility industry.
- Supervised the design and implementation of New Hampshire's first in the nation retail competition pilot program.
- Prepared and presented expert testimony before the NHPUC regarding the stranded cost aspects of the Restructuring Settlement Agreement submitted by Public Service Company of New Hampshire ("PSNH") and various settling parties. Testimony presents an analysis of PSNH's stranded costs and makes recommendations regarding the recoverability of such costs.
- Prepared and presented expert testimony on behalf of the NHPUC before the Federal Energy Regulatory Commission regarding the Order 888 calculation of wholesale stranded costs for utilities receiving requirements power supply service.
- Presented expert testimony on the rate and revenue requirement implications of embedded and marginal cost-of-service studies prepared by New Hampshire distribution companies.

EMPLOYMENT HISTORY:

La Capra Associates — Boston, Ma
Senior Consultant — *1999 - present*

New Hampshire Public Utilities Commission — Concord, NH
Director, Electric Utility Restructuring Division — *1993 - 1999*
Manager, Least Cost Planning, Economics Department
Gas and Electric Utility Analyst, Economics Department

Electricity Council — London, England
Pricing Specialist, Retail Tariff Policy Section, Commercial Department — *1977 - 1987*
Information Officer, Secretary's Office

EDUCATION

University of Sussex Space Physics Laboratory — Sussex, England
Ph.D. candidate in Theoretical Plasma Physics — *1977*
Withdrew in 1997 to accept position with the Electricity Council.

University of Sussex — Sussex, England
B.S., Theoretical Physics — *1975*

RECENT REPORTS

Comments on Proposed Restructuring Settlement Agreement Filed by Unitil Companies, March 2002, prepared for the Staff of NHPUC.

California Energy Markets: Pressures Have Eased, but Cost Risks Remain, December 2001, prepared for the California State Auditor, Bureau of State Audits.

Report of the Fair Market Value for Millstone Generation Assets, April 19, 2001, prepared for the Town of Waterford, Connecticut.

Restructuring New Hampshire's Electric Utility Industry: Final Plan, February 1997, principal author, prepared for New Hampshire Public Utilities Commission.

TESTIMONY

Forum	Client	Topic
Arkansas Public Commission	General Staff of the claim of EAI	Testimony regarding application by EAI to form RTO. 2001
Arkansas Public Service Commission	General Staff of the Arkansas Commission	Surrebuttal testimony regarding the stranded cost claim of EAI. December 4, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the stranded cost claim of Entergy Arkansas Inc. ("EAI"). September 19, 2000
Ohio Public Service Commission	Ohio Office of the Consumer Counsel	Testimony regarding the stranded cost claims submitted by the AEP Companies. April 2000
Federal Energy Regulatory Commission	New Hampshire Public Utilities Commission	Affidavit attached to Motion to Reopen regarding methodology to calculate stranded costs. June 2001
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff Advocates	Testimony regarding restructuring settlement submitted by PSNH. November 30, 1999
Federal Energy Regulatory Commission	New Hampshire Public Utilities Commission	Cross-Answering Testimony in Docket No. ER98-1440. March 11, 1999
Federal Energy Regulatory Commission	New Hampshire Public Utilities Commission	Answering Testimony in Docket No. ER98-1440. January 26, 1999
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff Advocates	Testimony regarding restructuring settlement submitted by Unitil Companies. October 7, 1998
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff Advocates	Testimony regarding restructuring settlement submitted by NEES Companies. April 15, 1998
New Hampshire Public Utilities Commission	Governor of the State New Hampshire	Testimony proposing interim stranded cost charges for PSNH. December 1997
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding restructuring filing submitted by PSNH. October 17, 1997
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding integrated least cost resource plan of the NHEC. May 17, 1995

New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding integrated least cost resource plan of PSNH. October 3, 1994
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding renegotiated rates for biomass SPP. June 27, 1994
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding transportation rates for natural gas company. June 20, 1994
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding demand-side programs submitted by the NHEC. April 15, 1994
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Suppl. testimony regarding power purchase contracts for renewable resources. December 20, 1993
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding power purchase contracts for renewable resources. December 1, 1993
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding costs and benefits of a partial purchase of a nuclear plant. September 17, 1993
New Hampshire Public Utilities Commission	New Hampshire Comm. Staff	Testimony regarding integrated least cost resource plan of PSNH. May 7, 1993

LEE SMITH

LA CAPRA ASSOCIATES
Senior Economist

Ms. Lee Smith is a Managing Consultant and Senior Economist at La Capra Associates. Ms. Smith has twenty years experience in utility economics and regulation. Her work has encompassed all aspects of utility pricing, cost analysis, forecasting, and both demand-side and supply planning in electric, gas, and water utility cases. Ms. Smith has analyzed issues of electric rate design, including rate unbundling and appropriateness of utility costs in 17 different states for a multitude of utilities and other entities. As a consultant, her clients have included gas and electric utilities, regulatory commissions and other public bodies. Previous to La Capra Associates, Ms. Smith was employed as the Director of Rates and Research at the Department of Public Utilities.

RELEVANT EXPERIENCE

- Modified cost of service allocations and testified on delivery service rate design on behalf of Illinois consumer advocates.
- Estimated retail class generation rates under continued regulated and retail access Arkansas Public Utilities Commission Staff; analyzed proposed change to System Resource Agreement by Entergy.
- Assisted the Arizona Corporation Commission in developing unbundled rates for all Arizona utilities; preparing positions, and negotiating with utilities on stranded cost and rate design.
- Advised Pennsylvania Office of the Public Advocate staff in restructuring proceedings; presented testimony on cost functionalization and rate unbundling in eight cases.
- Developed allocated cost of service studies and rates for a number of small utilities that required use of borrowed load data.
- Represented the Massachusetts Department of Energy Resources at NEPOOL committees engaged in developing the New England Independent System Operator, and an Open Access Transmission Tariff for New England.
- Directed Nantucket Electric Company in development of full load research program for small island utility for use in cost allocation and load forecasting.

EMPLOYMENT HISTORY

La Capra Associates — Boston, MA
Managing Consultant — *1984 - present*

Department of Public Utilities — Boston, Ma
Director of Rates and Research — *1982 - 1984*

EDUCATION

Tufts University — Medford, MA
Ph.D. in Economics, all but dissertation — *1966 - 1969*
Economics Department Fellowship

Boston College — Boston, MA
Study of Statistics — *1966*

Brown University — Providence, RI
B.A. with Honors, International Relations and Economics — *1965*
Prize in International Relations

PROFESSIONAL

Bunting Institute Fellowship — *1970 - 1971*

RECENT PUBLICATIONS

Non-price Issues in Gas Supply Planning, NATIONAL REGULATORY RESEARCH INSTITUTE, Biennial Regulatory Research Conference, 1994

The Economic Impact of Hurricane Agnes on the Chesapeake Bay in Maryland, JOHN HOPKINS PRESS

"*Development and Implementation of Restructuring in New England*", Institute of Public Utilities at Michigan State University Williamsburg Conference, December 1995

"*Planning for Gas and Electric Reliability*", NARUC Biennial Regulatory Information Conference, Vol. II, 1994

DESCRIPTION OF SELECTED PROJECTS

Arizona Corporation Commission Staff *2002*
Citizens request for increase in PPFAC to recover $87 million in power costs.

Massachusetts Water Resources Authority *2002*
Testified against BECo request to raise delivery service rates.

Illinois Citizens Utilities Board *2001*
Testified on appropriate distribution cost allocation and rate design.

Arkansas Public Service Commission Staff *2001*
Analysis of generation prices under competition and under deregulation, supported by testimony.

Pennsylvania Office of the Consumer Advocate *2001*
Testified against GPU's request to increase its Provider of Last Resort Rates.

Texas Retailers Association *2000*
Testified as to the appropriate cost of service for three major Texas utilities, focusing on transition costs, transmission plant increases, and support services costs allocated to regulated affiliates.

Burlington Electric Department *2000*
Testimony on Transportation Rate proposed by Vermont Gas Systems.

Arkansas Public Utilities Commission *2000*
Estimated retail class rates under continued regulated and retail access.

Hawaii Division of Consumer Advocacy *2000*
Prepared allocated cost of service study and rate design for the Hawaii Electric Company.

Arizona Corporation Commission *2000*
Helped develop Codes of Conduct for Electric Affiliates; testified in stranded cost case for Arizona Electric Cooperative.

Arkansas Public Utilities Commission *1999*
Assisted in market power docket, standard offer and default service policy development, rate unbundling.

Ohio Consumer's Counsel *1999*
Advised OCC on stranded generation costs and retail market generation costs.

Arizona Corporation Commission *1998*
Assisted ACC in cases that will develop unbundled rates for all regulated Arizona utilities; testified on stranded cost and retail access for AEPCO, APS, and TEP.

Maryland Office of the People's Counsel *1998*
Advised on stranded cost, prepared analysis and testimony on rate unbundling for PEPCO and Delmarva.

Burlington Electric Department *1998*
Prepared testimony on interruptible gas transportation rate for an electric generator.

Pennsylvania Office of the Consumer Advocate *1997*
Analyzed and prepared testimony on rate unbundling in eight major utility cases; advised OCA on stranded cost; assisted in testimony on stranded cost and market price; assisted in settlement discussions.

Maine Office of the Public Advocate *1997*
Prepared testimony on Bangor Hydro Electric emergency rate and normal rate proceeding; issues included Maine Yankee, replacement power costs, depreciation rates, and cost mitigation.

Maryland/Pennsylvania Public Advocates *1997*
Advised staff of both public advocates on PJM restructuring, including analysis of FERC filings and ongoing development of market structures and ISO.

Massachusetts Division of Energy Resources *1997*
Assisted DOER in drafting restructuring legislation, negotiating additional restructuring settlements with utilities, and with development of New England ISO.

New Hampshire Public Utilities Commission *1996*
Assisted Commission staff in writing Draft Order on Restructuring; prepared discovery for utilities; prepared discovery questions for hearings on various issues, including corporate unbundling, market structure, transmission, stranded cost theory, measurement, and mitigation.

Massachusetts Division of Energy Resources *1996*
Represented the DOER at NEPOOL committees engaged in developing an Independent System Operator, a revised NEPOOL Agreement, and an

Open Access Transmission Tariff for New England. Assisted the DOER in

other matters including development of model for Boston Edison pilot program based on proxy for competitive market real-time pricing.

CMEEC *1996*
Developed methodological basis for rate unbundling for the five Connecticut municipal utilities that are members of CMEEC.

Black Hills Power and Light Company, South Dakota *1995*
Advised Company on development of ancillary services and open access transmission rates.

Pennsylvania Office of the Consumer Advocate *1995*
Assisted with preparation of comments on restructuring issues.

Maine Office of the Public Advocate *1995*
Prepared alternative marginal cost study on Maine Public Service Company. Presented testimony advocating allocation of excess costs on the basis of generation allocators rather than EPMC.

Massachusetts Division of Energy Resources *1995*
Assisted DOER in all aspects of electric industry restructuring, from rate unbundling to planning and developing revised market structure for the New England Power Pool.

Littleton Water and Light Department, N.H. *1995*
Developed retail wheeling rate; advised on retail wheeling issues.

Boston Edison Company *1995*
Presented rate design workshop for Company personnel to assist in preparing for restructuring.

World Bank *1995*
Developing conditions under which State of Orissa, which is privatizing its electric distribution system, should consider revaluation; assisting with other restructuring issues.

Division of Energy Resources *1994*
Advised DOER on position on changes in Integrated Resource Management, including proposal to open Transmission and Distribution access to meet resource needs.

Black Hills Power and Light Company, South Dakota *1994*
Advised Company on rate treatment and phase-in of major new generating unit,

development of wholesale transmission rate, and response to retail wheeling.

New Hampshire Office of the Consumer Advocate *1994*
Advised Office on retail wheeling concerns; prepared testimony on cost of service, cost allocation and marginal cost presented by an electric utility.

Town of Fort Fairfield *1994*
Prepared response of town to CMP's threat to shut down a renewable energy facility following state-financed buyout of a high-priced unit contract, resulting in settlement.

Constellation Energy *1994*
Projected market price of power, advised developer on potential market.

Stow Electric Energy Study Committee *1994*
Advised committee on setting up new municipal utility, based upon results of response to RFP for provision of power and operations services, negotiated with bidders.

Massachusetts Department of Energy Resources *1993*
Assisted with analysis of economic impact of retiring older generating plants to meet Clear Air Act Targets.

Eastern Energy Associates *1993*
Directed analysis and computation of avoided costs of a major electric utility.

Maine Public Utility Commission Staff *1993*
Directed Staff's case in opposition to Central Maine Power Comp.'s request that it be allow to market power at below marginal cost rates; presented testimony on impact of CMP's proposal.

Office of the People's Counsel, Washington D.C. *1993*
Advised Office, presented testimony on appropriate recovery of deferred and present costs of ongoing Least Cost Planning program.

Plattsburgh Municipal Lighting Department *1993*
Advised utility on selection of least-cost power contracts.

Nantucket Electric Company *1993*
Directed development of long-run end-use load forecast for tourism-based economy.

Massachusetts Municipal Wholesale Electric Company *1992*

Analysis of and testimony on economic inefficiencies created by Bay State pricing of

interruptible gas to Stony Brook generating unit.

Woodsville Water and Light Department *1992*
Advised Department on least-cost power supply and led negotiations with potential suppliers, resulting in significant long-run savings.

Stow Electric Energy Study Committee *1992*
Advised Committee on advisability of separating from municipal electric system currently serving the town; analyzed costs and benefits of different sources of supply.

Boston Edison Electric Company *1992*
Assisted in analysis of customer's demand for experimental color-corrected streetlighting, resulting in settlement of long-standing dispute.

Plattsburgh Municipal Light Department *1992*
Prepared rate case, including revenue needs, allocation of costs, and rate design; directed Company in reorganization of billing data.

Altresco *1992*
Advised on siting, fuel costs, and bidding of potential new intermediate power project.

Middleton Electric Light Department *1992*
Renegotiation of contract for transmission of all power to the utility.

Nantucket Electric Company *1992*
Directed revision of load research sampling (determining appropriate sample size and selection).

Nantucket Electric Company *1991*
Applied load research data to develop detailed (daily) demand and revenue projections.

Nantucket Electric Company *1991*
Assisted in rate case, including allocating costs between customer classes, developing marginal costs, designing rates.

Nantucket Electric Company *1991*
Presented testimony on externalities created by emissions from electric generation on Nantucket Island, and potential impact of inclusion of externalities on ratepayers.

Illinois Office of Public Counsel *1990*

Provided expert advice to consumer advocate group on developing state least-cost planning guidelines for gas utilities.

Plattsburgh Municipal Light Department *1990*
Developed new rate for large, 46 KV service customers, directed development of value of plant serving the proposed class.

Middleton Electric Light Department *1989*
Developed innovative cost-based rate for very large interruptible customer and negotiated with both NEPOOL and customer.

Littleton Water and Light Department *1989*
Updated Company's revenue allocation and rates to reflect new marginal-cost based wholesale power tariff.

Boston Edison Company *1989*
Assisted Company in analysis of jurisdictional cost allocations in major court dispute; developed company response to FERC order on allocation of distribution/transmission plant.

Reading Municipal Light Department *1988*
Analyzed power supply options, determined least-cost options.

Wellesley Municipal Light Plant *1987*
Redesigned rates for municipal utility, including allocating costs, estimating marginal costs, and designing rates, including a time-of-use rate for largest customers.

DANIEL E. PEACO

LA CAPRA ASSOCIATES
Managing Director

Daniel Peaco is an electric industry planning specialist with 20 years of experience. His expertise includes power markets and marketing, strategic planning, pricing and price forecasting, power procurement and contracts, and power systems planning. Mr. Peaco has 10 years of management experience in the utility industry and has significant experience as an expert witness and as an advisor to senior utility managers and public policy officials. His consulting practice has included a range of electric restructuring projects, including stranded cost assessment and mitigation, generation asset valuation, strategic planning, design and pricing of default service, competitive market formation and pricing, and market power. In addition to his tenure at La Capra Associates, he has held management and planning positions at Central Maine Power, CMP International Consultants, Pacific Gas & Electric, and the Massachusetts Energy Facilities Siting Council.

RELEVANT EXPERIENCE

- Led LCA team in review of the California Department of Water Resources 2001 Power Procurement Program. LCA advised and assisted the California Bureau of State Audits conduct its audit of this $43 billion power contracting effort. 2001.
- Led LCA team in review of San Diego Gas & Electric's approach to the California Block Forward Markets during the Fall 1999 to Summer 2000 period. Assist in the formation of testimony presented on behalf of the California Office of the Ratepayer Advocate before the California PUC. 2001.
- Prepared expert testimony and analysis regarding the outlook for benefits from the deregulation of the Arkansas retail generation market on behalf of the General Staff of the Arkansas Public Service Commission in an industry restructuring proceeding regarding the timing and approach to implementation of retail competition. 2000.
- Presented expert testimony before the Arkansas Public Service Commission regarding the design of standard service package, market power, competitive billing services in preparation for retail open access. 2000.
- Directed the analysis of the value of the generating assets of five Ohio investor-owned utilities on behalf of the Ohio Consumers Counsel in Ohio industry restructuring proceedings regarding generation asset value, transition costs, and retail market formation in preparation for adjudication and support of settlement negotiations. 1999 - 2000.
- Presented expert testimony on the reliability, economic and environmental need for new power supplies in New England before the Massachusetts, Connecticut,

and Rhode Island Energy Facility Siting Boards on behalf of seven proposed gas-fired, combined-cycle merchant power plants. 1997 - 2001.

- Directed analysis of Pennsylvania Power and Light's restructuring plan on behalf of the Pennsylvania Office of the Consumer Advocate; assessed the value of PP&L's generation assets and the company's claim for $4 billion in stranded costs. 1997.
- On behalf of seven proposed gas-fired, combined-cycle merchant power plants, prepared and presented expert testimony on the reliability, economic and environmental aspects of the need for new power supplies in New England before the Massachusetts, Connecticut, and Rhode Island Energy Facility Siting Boards. 1997 - 2001.
- Provided litigation support and deposition testimony regarding dispute of pricing provisions in two purchased power agreements on behalf of Central Maine Power Company. 1999 - 2001.
- Directed a market valuation analysis of a 1000 MW New England generation portfolio, including a 360 MW hydroelectric system, assisting a major national generating company with the development of a purchase offer. 1997 - 1998.
- Directed an assessment of an assessment of the engineering, licensing, and economic future of a small scale hydroelectric facility for the Village of Barton, Vermont, including the development of options for a long term relicensing plan and continued ownership. 1998 - 1999.
- Directed market valuation studies for three New England merchant power plant developers, supporting their project prospectus for potential lenders and equity participants. 1997 - 1998.
- Directed the analysis of Pennsylvania Power and Light's restructuring plan on behalf of the Pennsylvania Office of the Consumer Advocate; assessed the value of PP&L's generation assets and the company's claim for $4 billion in stranded costs. 1997.
- On behalf of Central Maine Power (CMP), prepared and presented expert testimony before the Maine Public Utilities Commission on the economic benefits of a proposed 30 year, 1000 MW power contract with Hydro Quebec. 1987 - 1988.
- Directed CMP's power system planning activities, assessing power system economics, evaluating numerous IPP power sales contract economics, forecasting long-term market prices, preparing power system development plans, and preparing economic studies for the federal relicensing applications of several of CMP's hydropower facilities. 1987 - 1993.
- Assessed the economics and reliability of PG&E's hydropower system, identifying opportunities for capital improvements and options for operations management. 1983 - 1985.

EMPLOYMENT HISTORY

La Capra Associates — Boston, MA
Managing Director — *1996 - present*

Central Maine Power Company — Augusta, ME
Manager, Industrial Marketing and Economic Development — *1986 - 1996*
Principal, CMP International Consultants
Director, Power Supply Planning
Power Supply Planning Analyst

Pacific Gas & Electric Company — San Francisco, CA
Power Supply Planning Analyst — *1981 - 1986*
Hydropower Planning Analyst
Cogeneration Contracts Analyst

Massachusetts Energy Facilities Siting Council — Boston, MA
Planning Engineer — *1978 - 1979*

EDUCATION

Thayer School of Engineering, Dartmouth College **Hanover, NH**
M.S. in Engineering Sciences, Resource Systems and Policy Design — *1981*

Massachusetts Institute of Technology **Cambridge, MA**
B.S. in Civil Engineering, Water Resource Systems — *1977*

PROFESSIONAL

Registered Professional Engineer, State of Maine — *Current*

Board Member, Greater Portland Economic Development Council — *1995 - 1996*

Chairman, New England Power Pool's Power Supply Planning Committee — *1993*

Central Maine Power representative, New England Power Pool's Power Supply Planning Committee — *1990 - 1993*

Central Maine Power representative, Utility Planning Task Force, Electric Power Research Institute — *1993*

RECENT REPORTS

Califonia Energy Markets: Pressures Have Eased, but Cost Risks Remain, California Bureau of State Audits, December 21, 2001. Lead Consultant and a Principal Author.

Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas, Arkansas General Staff's Report, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 4, 2001. Principal Author.

Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas, Arkansas General Staff's Report, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 29, 2000. Principal Author.

Wholesale Market Development: Timing and Issues Survey of Activity in Other Regions, FERC Initiatives, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 29, 2000. Principal Author.

Retail Market Development: Timing and Issues Survey of Other States, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 29, 2000. Principal Author.

The Progression toward Retail Competition in Arkansas' Neighboring States, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 29, 2000. Principal Author.

Arkansas General Staff Proposal and Initial Comments, In The Matter of a Generic Proceeding to Establish Uniform Policies and Guidelines for a Standard Service Package, Docket No. 00-148-R, June 13, 2000. Principal Author.

Arkansas General Staff Initial Comments, In The Matter of a Generic Proceeding to Determine if Metering, Billing, and Other Services Are Competitive Services, Docket No. 00-054-U, March 31, 2000. Principal Author.

Arkansas General Staff Initial Comment and Proposed Market Power Analysis Minimum Filing Requirements, In The Matter of a Generic Proceeding to Establish Filing Requirements and Guidelines Applicable to Market Power Analyses, Docket No. 00-048-R, March 28, 2000. Contributing Author.

Vermont Electricity Prices: Regional Competitiveness Outlook; Implications of Restructuring in New England and New York, February 2000 Edition, prepared for Central Vermont Public Service. Principal Author.

Projected Retail Price of Electricity for Massachusetts Electric Company, Boston Edison Company, and Western Massachusetts Electric Company, September 1999, prepared for Massachusetts Municipal Wholesale Electric Company. Principal Author.

Comments of the Commonwealth of Massachusetts Division of Energy Resources, in the Investigation by the Department of Telecommunication and Energy into Pricing and Procurement of Default Service, July 1999 (Initial and Reply Comments). Contributing Author.

Need for Power Supply: The New England Power Pool and the State of Rhode Island, March 1999, prepared for Indeck – North Smithfield Energy Center.

Vermont Electricity Prices: Regional Competitiveness Outlook; Implications of Restructuring in Northeast States, a Report to the Working Group on Vermont's Electricity Future, November 1998, prepared for Central Vermont Public Service. Principal Author.

TESTIMONY

Forum	Client	Topic	
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas.	
		Prefiled Testimony	September 4, 2001
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas.	
		Prefiled Testimony	September 29, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the establishment of uniform Policies and guidelines for a Standard Service Package.	
		Staff Proposal and Comments	June 13, 2000
		Reply Comments	July 21, 2000
		Sur reply Comments	August 2, 2000
		Oral Testimony	August 8, 2000
		Petition for Rehearing	
		Rebuttal Testimony	November 15, 2000
		Oral Testimony	November 29, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the determination of the merits of declaring retail billing services competitive effective At the start of retail open access.	
		Oral Testimony	June 27, 2000
		Prefiled Rebuttal Testimony	June 23, 2000
		Prefiled Testimony	June 16, 2000
		Oral Testimony	May 10, 2000
Arkansas Public	General Staff of the	Testimony regarding the minimum filing requirements	

Service Commission	AK Public Service Comm.	for market power studies to be filed by the Arkansas Electric utilities and affiliated retail companies.	
		Oral Testimony	June 1, 2000
Amer. Arb. Assoc. No. 50T 198 00197-98	Vermont Joint Owners	Testimony regarding economic damages resulting from alleged breach of a long-term purchase power agreement between Hydro-Quebec and Vermont utilities (VJO).	
		Oral Testimony	May 25, 2000
		Prefiled Rebuttal Testimony	February 10, 2000
		Prefiled Testimony	August 13, 1999
Rhode Island Energy Facilities Siting Board	Indeck-North Smithfield, L.L.C.	Testimony regarding economic, reliability and environmental need for power in the Rhode Island and New England power markets regarding the need for new, merchant power facility.	
		Prefiled Testimony	August 16, 1999
		Oral Testimony	August 17, 2000
		Prefiled Testimony	January 26, 2001
		Oral Testimony	March 23, 2001
Civil Litigation Maine Superior Court Docket No. CV-98-212	Central Maine Power Co.	Factual and expert witness in litigation regarding pricing provisions of a purchased power agreement between Central Maine Power and Regional Waste Systems.	
		Deposition Testimony	May 5, 1999
Connecticut Energy Facilities Siting Council Docket No. 190	PDC – El Paso Meriden LLC	Testimony regarding economic, reliability and environmental need for power in the Connecticut and New England power markets regarding the need for new, merchant power facility.	
		Prefiled Testimony	January 25, 1999
Rhode Island Energy Facilities Siting Council Docket No. SB-98-1	R. I. Hope Energy, L. P.	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	November 4, 1998
		Prefiled Testimony	October 30, 1998
Massachusetts Energy Facilities Siting Council Docket No. EFSB-91-101A	Cabot Power Corp.	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	May 27, 1998
		Prefiled Testimony	August 15, 1997
Massachusetts Energy Facilities Siting Council Docket No. EFSB-97-2	ANP Blackstone Energy	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	April 6, 1998
		Prefiled Testimony	January 23, 1998
Massachusetts Energy Facilities Siting Council Docket No. EFSB-97-1	ANP Bellingham	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	February 3, 1998
			January 28, 1998
Rhode Island Energy	Tiverton Power Associates LP	Testimony regarding economic, reliability and environmental	

Facilities Siting Board Docket No. SB-97-1		need for power in the Rhode Island and New England power markets regarding the need for new, merchant power facility. Oral Testimony Prefiled Testimony	 October 15, 1997 October 1, 1997
Maine Public Utilities Commission Docket No. 92-102	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the prudency of power purchase contract decisions with regard to contract awards and ongoing contract management. Oral Testimony Deposition Testimony Prefiled Rebuttal Testimony Prefiled Testimony	 July 1993 February 25, 1993 March 1, 1993 June 7, 1993 June 15, 1992
Maine Public Utilities Commission Docket No. 92-315	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the setting of long-term avoided costs, CMP's Energy Resource Plan, and the relationship of marginal costs of generation to embedded costs. Supplemental Prefiled Testimony Prefiled Testimony	 April 20, 1993 February 17, 1993
Maine Public Utilities Commission Docket No. 87-261 Docket No. 88-111	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the setting of long-term avoided costs, CMP's Energy Resource Plan, and the proposal for a 900 MW power Contract with Hydro Quebec. Oral Testimony Prefiled Testimony	 Summer 1988 October 31, 1987

ROBERT J. HIX

LA CAPRA ASSOCIATES
Director, Denver Office / Managing Consultant

Robert J. Hix joined LaCapra Associates as Managing Consultant and Director – Denver Office, to establish a stronger presence in the West. His experience enhances the organizations' ability to meet client needs efficiently in the areas of ratemaking and utility planning, distributed generation, renewable energy public policy and energy efficiency. Prior to joining La Capra Associates, Mr. Hix was appointed Colorado Public Utilities Commission Chairman by Governor Roy Romer and was confirmed by the Colorado Senate. His term expired on January 8, 2001. He is a member of the Advisory Council to the Board of Directors of the Electric Power Research Institute and is a member of the Adequacy Committee of the North American Electric Reliability Council. Previous to his appointment, Mr. Hix was a Senior Engineering Analyst with the Colorado Office of Consumer Counsel, which represents residential, small business and agricultural customers on issues before the Public Utilities Commission. As Senior Engineering Analyst, Mr. Hix testified as an expert in engineering and rate matters at hearings before the Public Utilities Commission. His primary role was to determine the policy and regulatory implications of rate changes and allocation among various customer classes.

RELEVANT EXPERIENCE

- Served as Chairman of the Colorado Public Utilities Commission from May 1994 to July 1999. Continued as Commissioner from July 1999 until May 10, 2001. Regulate transportation, intrastate railroad, water, telecommunications, electric, natural gas and steam utility companies operating in the state of Colorado. Was a member of the National Association of Regulatory Utility Commissioners (NARUC) Committee on International Relations, Committee on Electricity and Subcommittee on Strategic Issues. Earlier, served on NARUC's Committee on Gas. Member of the Advisory Council to the Board of Directors of the Electric Power Research Institute and member of the Planning Committee of the North American Electric Reliability Council. Member of the Advisory Council of the New Mexico State University Institute of Public Utilities.

- Conducted a Regulatory Partnership with the Orissa Electricity Regulatory Commission (state in India). Over a two period, advised the OERC; India's Central Electricity Regulatory Commission (Federal); the Administrative Staff College of India; the Commission for the state of Uttar Pradesh; and the Tata Energy Research Institute.

- Represented the interests of residential, small business, and agricultural customers, testified as expert witness on engineering and rate matters at hearings before the Public Utilities Commission. Primary role was to determine the policy and regulatory implications of rate and regulatory changes among various customer classes. Coordinated activities of outside expert consultants.

- Coordinated activities of the Public Service Company of Colorado division relative to a Management Audit ordered by the Colorado Public Utilities Commission and performed special assignments and contract analysis for the Division Manager.

- Initiated a project to develop procedures and direct activities necessary for initiating, negotiating and managing power contracts. Resulted in being named Power Contracts Administrator responsible for the satisfactory completion of arrangements for Bulk Power Purchase, Transmission Interconnection and Joint Venture Projects with other utilities for power plants and transmission facilities.

- Developed and calculated Fuel Cost Adjustments, Gas Cost Adjustments and refund applications and prepared and submitted applications to the Colorado PUC for Public Service Company.

- Developed Gas Rate Riders for Western Slope Gas Company and Cheyenne Light, Fuel and Power Company and prepared applications to the appropriate Commissions.

- Prepared technical exhibits and data responses for rate proceedings and energy related matters.

- Prepared applications for Special Rate Schedules to the Federal Power Commission (Federal Energy Regulatory Commission).

- Involved with Cost of Service Analysis for Electric Rate Design and actual Electric and Gas Rate Design to produce the revenue requirements of Public Service Company.

- In addition to normal distribution engineering duties for the Public Service Company of Colorado, was responsible for estimation, negotiation and purchase of secondary and "in-building" services from electrical contractors for Public Service Company.

EMPLOYMENT HISTORY

La Capra Associates — Denver, CO
Director / Managing Consultant — *2001 - present*

Colorado Public Utilities Commission — Denver, CO
Chairman/Commissioner — *1994 - 2001*

Colorado Office of Consumer Counsel — Denver, CO
Senior Engineering Analyst — *1985 - 1994*

U.S. Peace Corps — Sigatoka, Fiji
Peace Corps Volunteer, Mathematics and Physics Teacher — *1984*
Lomowai Secondary School

Public Service Company of Colorado — Denver, CO
Electric System Planning Staff Assistant — *1971 - 1983*
Power Contracts Administrator
Special Projects Analyst, Special Projects Division
Rate Engineering Technician, Rates and Regulations Division
Field Engineer, Electric Distribution Engineering Department

EDUCATION

Michigan State University Institute of Public Utilities — East Lansing, MI
Williamsburg Conference, Advanced Regulatory Studies, and Regulatory Studies Program — *1974 - 1987*

University of Colorado — Denver and Boulder, CO
Graduate coursework in Combinatorial Analysis, Management Science, Marketing and Business Statistics — *1974 - 1975*

International Correspondence School
Diploma, Electric Distribution Engineering — *1974*

Regis College — Denver, CO
B.S. in Mathematics with a Minor in Physics — *1970*

PROFESSIONAL

Member of the Advisory Council to the Board of Directors
Electric Power Research Institute — *1999 - present*

Member of the Advisory Council, New Mexico State University
Center for Public Utilities — *1999 - present*

Member of the Planning Committee, North American Electric Reliability Council — *1998 - 2001*

ARTHUR FREITAS

LA CAPRA ASSOCIATES
Analyst

Arthur Freitas has over 4 years experience in the energy industry, in both the natural gas and electric markets. His experience includes cost of service analysis for natural gas and electric utilities, rate design analysis, unbundling analysis, natural gas and electric market price forecasting, retail electric and natural gas market analysis, and retail energy planning and procurement. Since joining La Capra Associates in May 2000, Mr. Freitas has assisted in a number of regulatory proceedings, which include electric and natural gas utility rate cases, electric restructuring hearings, and utility prudency reviews.

RELEVANT EXPERIENCE

- Analyzed the cost of service study submitted by Hawaii Electric Light Company in its 2000 rate case. Assisted in developing expert testimony on behalf of the Hawaii Division of Consumer Advocacy.
- Analyzed the allocated cost of service studies of three Texas distribution utilities in a restructuring proceeding. Assisted in the preparation of expert testimony on the reasonableness of the cost of service studies on behalf of large commercial end users of electricity.
- Prepared and submitted to the Massachusetts utility regulator, the bi-annual Cost of Gas Adjustment factor and the annual Cost of Gas Reconciliation for the Blackstone Gas Company.
- Prepared an embedded cost of service study for Blackstone Gas Company in its most recent rate case. Assisted in developing expert testimony on the reasonableness of the expenses included in the cost of service study.
- While at Boston Gas Company, prepared the Cost of Gas Adjustment factor and Annual Reconciliation and submitted the filing to the Massachusetts utility regulator.
- Prepared the compliance filing for Boston Gas Company's performance based ratemaking authority and performed the rate design to allocate the allowed revenue to the various rate classes.
- Assisted the Massachusetts Water Resources Authority (MWRA) in obtaining an electric power supply for its wastewater treatment plant in Boston Harbor. Analysis included estimating the cost savings of competitive electric supply and examining the best method to utilize MWRA's on-site generation resources to maximize the value of the generation resources.

EMPLOYMENT HISTORY

La Capra Associates — Boston, MA
Analyst — *2000 - present*

Boston Gas Company — Boston, MA
Rate Analyst — *1998 - 2000*

EDUCATION

Marquette University — Milwaukee, WI
M.S. in Applied Economics — *1998*

Marquette University — Milwaukee, WI
B.A., Economics and Finance — *1994*

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ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

Proposal to The North Dakota Public Service Commission

Request for Proposal for Investigation of Montana-Dakota Utilities Company's Gas Rate Increase

Case No. PU-399-02-183

Prepared By

GDS Associates, Inc.

May 30, 2002

Georgia: Suite 800, 1850 Parkway Place, Marietta, Georgia 30067 • (770) 425-8100 • FAX (770) 426-0303
Texas: Suite 800, 919 Congress Avenue, Austin, Texas 78701 • (512) 494-0369 • FAX (512) 494-0205
Maine: 10 Tanning Brook Road, Manchester, ME 04351 • (207) 623-3649 • FAX (207) 623-3649
New Hampshire: Suite 205, 1181 Elm Street, Manchester, NH 03110 • (603) 471-0336 • FAX (603) 471-0376
Wisconsin: Suite 212, 437 So. Yellowstone Drive, Madison, WI 53719 • (608) 273-0182 • FAX (608) 273-0132
Washington: Suite 16, 1000 Harris Avenue, Bellingham, WA 98225 • (360) 734-4525 • FAX (360) 734-4588
Web Site: http://www.gdsassociates.com

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I. INTRODUCTION

The North Dakota Public Service Commission ("Commission") has issued a request for proposals from firms with expertise in natural gas rate matters, including cost of capital, cost of service, and rate design, for assistance with an investigation of Montana-Dakota Utilities Co.'s ("MDU") gas rate increase request in Case No. PU-399-02-183. The selected firm will investigate, analyze, and provide testimony regarding the fairness and reasonableness of MDU's proposed rates. The completion date for the investigation and written testimony is August 30, 2002.

II. DESCRIPTION OF GDS ASSOCIATES, INC.

Founded in 1986, GDS Associates, Inc. ("GDS") is a multi-utility consulting firm headquartered in Marietta, Georgia, with offices in Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; Madison, Wisconsin; Manchester, Maine; and Bellingham, Washington. During the past 15 years, GDS has grown to a 90-person firm that serves clients located in 46 states. GDS is a young, dynamic organization that has grown from a strong commitment to client service, backed by comprehensive experience, and state-of-the-art computer and information resources. With comprehensive consulting services related to public utilities, GDS can address the complex governmental, economic, engineering, accounting, environmental and scientific issues that impact utilities and their customers.

GDS serves a diverse base of clients, customer groups, publicly-owned utilities, municipalities, joint action agencies, law firms, government agencies, public service commissions and other consulting firms.

Major natural gas and electric utility services provided by GDS include regulatory consulting, resource planning, conservation and demand-side management consulting, industry restructuring and deregulated energy market analysis. GDS also has specialized skills in wholesale and retail rate studies and expert testimony; cost-of-service studies; energy efficiency program planning, implementation and evaluation; market research; statistical analysis; cogeneration feasibility studies; economic feasibility studies; RFPs for energy supply; contract negotiations with energy suppliers; financial forecasts; bond certification; load research and load forecasting; property valuation and territorial integrity services; management consulting services; and the development and application of computer models.

GDS consultants have significant experience in providing expert testimony on complex operational and ratemaking issues in regulatory proceedings before state and federal regulatory commissions. Examples of recent GDS projects are provided in Section V. of this proposal. GDS certifies that it complies with applicable provisions of the Americans with Disabilities Act of 1991. Additional information on GDS is available on our website, www.gdsassoc.com.

III. SCOPE OF SERVICES

1. Level of Investment – Work in this area will be limited in scope and will primarily rely on a review of the last rate case and historical comparisons. No cash working capital calculation will be performed. The majority of this work will be performed in the Austin office by Ellen Blumenthal, Jim Daniel and Valerie Anderson.

2. Cost of Capital – MDU's cost of capital includes long-term debt, preferred equity and common equity. The most critical element of the cost of capital is the return on equity component. To accurately determine MDU's appropriate cost of capital, GDS would expect to perform consulting duties including, but not limited to: analysis and review of MDU's filing, preparation of discovery, preparation of written testimony, presentation of oral testimony, cross-examination of expert witnesses, and assistance to staff in the preparation of proposed findings of fact. The majority of this work will be performed in the Marietta office by J. Bertram Solomon.

3. Cost of Service – A critical element of the cost of service is the appropriate level of weather normalized sales. The cost of service portion will also require a strong review of other operating and maintenance expenses. To accurately determine MDU's appropriate cost of service, GDS would expect to perform consulting duties including, but not limited to: analysis and review of MDU's filing, preparation of discovery, preparation of written testimony, presentation of oral testimony, cross-examination of expert witnesses, and assistance to staff in the preparation of proposed findings of fact. This work will be performed in the Marietta office by John Hutts and in the Austin office by Ellen Blumenthal, Simon Peña, and Chuck Loy.

4. Rate Design – In its application, MDU is seeking a significant increase to the monthly basic service charge. Should the Commission not accept this increase, MDU is arguing for the inclusion of a weather normalization adjustment. To develop the appropriate rate design, GDS would expect to perform consulting duties including, but not limited to: analysis and review of MDU's filing, preparation of discovery, preparation of written testimony, presentation of oral testimony, cross-examination of expert witnesses, and assistance to staff in the preparation of proposed findings of fact. The majority of this work will be performed in the Austin office by Jim Daniel and Valerie Anderson.

5. Depreciation Study – As MDU's last depreciation study was conducted in the early 1990's, the Commission may want to have a new study completed for this proceeding. To perform a new depreciation study for MDU, GDS would expect to perform consulting duties including, but not limited to: analysis and review of MDU's filing, preparation of discovery, preparation of written testimony, presentation of oral testimony, cross-examination of expert witnesses, and assistance to staff in the preparation of proposed findings of fact. The majority of this work will be performed in the Marietta office by Cary Cook.

IV. PERSONNEL

GDS has assembled an experienced team of economists, accountants, regulatory analysts and engineers for this project. Ms. Ellen Blumenthal will serve as overall project manager and will direct the analysis, expert testimony, data requests and recommendations. Ms. Blumenthal is a Senior Project Manager with GDS, a CPA and has over twenty years of experience in the utility industry.

The following GDS personnel will be involved in the project:

Name	Title	Location
John Hutts	Principal	Marietta, GA
J. Bertram Solomon	Vice President and Treasurer	Marietta, GA
Jim Daniel	Vice President	Austin, TX
Cary Cook	Senior Project Manager	Marietta, GA
Simon Peña	Senior Project Manager	Austin, TX
Charles Loy	Senior Project Manager	Austin, TX
Valerie Anderson	Project Consultant	Austin, TX
John Kirkpatrick	Associate Analyst	Austin, TX

Resumes for each member of the project team are provided in Attachment 1.

V. QUALIFICATIONS AND PRIOR EXPERIENCE

GDS Associates, Inc. has extensive experience in the natural gas utility industry, with a wide variety of projects such as gas rate case analysis and testimony, gas procurement strategies, analysis of the strategic plans and operating programs of natural gas utilities, benefit/cost analyses of alternative gas marketing and energy efficiency initiatives, contract negotiations, and market monitoring and research. A description of several recent natural gas utility related projects is provided below to give a sampling of GDS' experience in the natural gas industry. For all of the projects identified, GDS has provided the project title, the name of the client, the client's name address and phone number, and a description of the scope of work.

Project Name: **Review of Peoples Natural Gas Company Rate Request (Nebraska)**
Client Organization: Ninety-two Nebraska Municipalities
Client Reference: Roger Cox, Esq.
Harding, Schultz & Downs
P.O. Box 82028
Lincoln, Nebraska 68501-2028
Phone: 402-434-3000

Project Description: During 1995 and 1996, GDS reviewed and analyzed Peoples Natural Gas Company's (PNG) request for rate relief in its largest Nebraska rate area. This work was done on behalf of ninety-two Nebraska municipalities. In Nebraska, municipalities rather than the Nebraska Public Service Commission have jurisdiction over the rates of investor-owned natural gas utilities. Our report to the municipalities identified numerous revenue requirement and rate design issues including the following: (1) acquisition adjustment, (2) manufactured gas plant site clean up costs, (3) capital structure, (4) return on common equity, (5) projected plant additions, (6) self-insurance reserves, (7) income taxes, (8) legislative advocacy expenses, (9) materials and supplies inventory, (10) cash working capital, (11) the regulatory treatment of post-retirement benefits, (12) the allocation of affiliate costs, (13) customer growth, (14) weather normalization, (15) jurisdictional cost allocations and (16) rate design. One of the more controversial issues in the proceeding was the impact of UtiliCorp's acquisition of other gas distribution systems. GDS, in conjunction with municipal representatives and the municipalities' legal counsel, negotiated a settlement of the rate case with PNG. A similar rate review was conducted by GDS regarding PNG's proposed rate increase in 1991 and 1992.

Project Manager: Jim Daniel

Project Name: **Cost of Service Testimony in Arkansas Western Gas Company Rate Case**

Client Organization: Arkansas Attorney General

Client Reference: Shawn McMurray, Deputy Attorney General
Office of Arkansas Attorney General
CURAD Division
323 Center St., Suite 200
Little Rock, Arkansas 72201
501/682-2007

Project Description: GDS reviewed the cost of service study and proposed rate design of Arkansas Western Gas Company in Arkansas Public Service Commission Docket No. 97-019-U. Testimony was filed regarding the distribution of Arkansas Western's proposed revenue increase and regarding rate design issues. GDS also assisted in negotiating a settlement in the case.

Project Manager: Jim Daniel

Project Name:	**Natural Gas Procurement Strategy for the City of Chicago**
Client Organization:	City of Chicago
Client Reference:	Tyrone Evans Deputy Commissioner City of Chicago Department of General Services 30 North LaSalle Suite 3700 Chicago, IL 60602 Phone: (312)774-6045
Project Description:	GDS was retained by DMG-Maximus, a consulting firm, to assist the City of Chicago in preparing a natural gas procurement strategy. The City purchases gas on an aggregated basis to serve City facilities and has an option to participate in a gas purchasing consortium of other cities, government agencies and school districts. GDS identified and reviewed current strategy, conducted a market research survey, recommended a natural gas procurement strategy for short-long term conditions and assisted in the implementation of strategy.
Project Manager:	Simon Peña and Jim Daniel

Project Name:	**Testimony in U.S. Tax Court – Natural Gas Reg. Issues**
Client Organization:	Internal Revenue Service-Administrative Service Center
Client Reference:	Thomas E. Ritter, Esq. Office of Chief Counsel Internal Revenue Service North Florida District 400 W. Bay Street, Room 564 Jacksonville, FL 32202 Phone: 304-256-6000
Project Description:	GDS assisted the Internal Revenue Service (the Service) in its review of the proposed tax treatment of demand-side management and energy conservation project costs of Peoples Gas System, Inc., a local gas distribution company and subsidiary of Lykes Energy. GDS filed an expert opinion report with the U. S. Tax Court on behalf of the Service. Lykes Energy and the Service subsequently reached a favorable settlement in this proceeding.
Project Manager:	Jim Daniel

Project Name:	**Unbundled Natural Gas Cost of Service and Rate Study**
Client Organization:	Westfield Gas and Electric Light Department
Client Reference:	Joyce Bodak, Gas Supply Manager City of Westfield, Massachusetts P. O. Box 990 Westfield, Massachusetts 01086 Phone: 413-572-0100
Project Description:	In response to utility restructuring legislation in Massachusetts, GDS prepared an unbundled cost of service study of the City's natural gas utility and developed unbundled gas rates. The City's unbundled gas rates were subsequently implemented. The project also involved the review and analysis of unbundled rate and utility restructuring filings of investor-owned natural gas local distribution companies in Massachusetts.
Project Manager:	Jim Daniel

Project Name:	**Acquisition of Gas Distribution Facilities**
Client Organization:	City of Wahoo, Nebraska
Client Reference:	Paul Erickson, Utilities Director City of Wahoo, Nebraska 605 N. Broadway Wahoo, Nebraska 68066 Phone: 402-443-3222
Project Description:	GDS assisted the City of Wahoo, Nebraska in its planned acquisition of the gas distribution facilities of Peoples Natural Gas Company (PNG) within the city limits. The City offered to purchase PNG's facilities but was turned down by the Company. GDS provided expert testimony before the Condemnation Court appointed by the Supreme Court of Nebraska in litigation regarding condemnation proceedings.
Project Manager:	Jim Daniel

Project Name:	**Lone Star Pipeline Gas Transportation Rate Case**
Client Organization:	City of Garland, Texas
Client Reference:	Lambeth R. Townsend, Esq. Lloyd, Gosselink, Blevins, Rochelle, Baldwin & Townsend, P.C. 111 Congress Ave., #1800 Austin, Texas 78704 Phone: 512-322-5800
Project Description:	GDS assisted a coalition of cities in Texas review and analyze a proposed gas transportation rate (city gate rate) increase case by Lone Star Pipeline Company. Testimony was presented before the Texas Railroad Commission on revenue requirement issues related to operating expenses, income taxes, affiliate transactions, other

	revenues and Y2K costs. In addition, competition and merger-related issues were addressed.
Project Manager:	Jim Daniel

Project Name:	**Revise Current Electric, Natural Gas and Water Extension Policies**
Client Organization:	City Utilities of Springfield, Missouri
Client Reference:	John Twitty City Utilities of Springfield Missouri P. O. Box 551 Springfield, Missouri 65801 Phone: 417-831-8527
Project Description:	GDS is to review and revise City Utilities' current line extension policies so as to be more responsive in the emerging competitive and restructured utility environment. In addition, GDS is to survey the utility industry to obtain information about extension policies and practices of other utility companies and compile this information into a set of "most common" policies and unique and innovative policies. GDS will also develop a program for City Utilities and GDS to use in presenting the revised extension policies to the "public".
Project Manager:	Jim Daniel

Project Name:	**Review of Sales Forecast and Weather Normalization Adjustments**
Client Organization:	Michigan Attorney General
Client Reference:	Orgiakor N. Isiogu, Assistant Attorney General Attorney General's Office, Special Litigation Division 630 Law Building, P. O. Box 30212 Lansing, Michigan 48909 Phone: 517-335-0817
Project Description:	On behalf of the Michigan Department of Attorney General, GDS analyzed Michigan Consolidated Gas Company's (MichCon) sales forecast, weather normalization adjustments and other issues in two proceedings before the Michigan Public Service Commission. The two proceedings are MichCon's Gas Cost Review (GCR) filing, Case No. U-10105, and MichCon's application for a general rate increase, Case No. U-10150.
Project Manager:	Jim Daniel

Project Name:	**Texas Unbundled Cost of Service/Excess Cost Over Market Dockets**
Client Organization:	Texas Office of Public Utility Counsel
Client Reference:	James Rourke Assistant Public Counsel Texas Office of Public Utility Counsel 1701 M. Congress Ave., Suite 9-180 Austin, Texas 78711 Phone: 512 936 7500
Project Description:	Participated in gas price forecast workgroup, evaluated utility-filed model results and testimony, developed discovery and testimony on stranded cost quantification in several contested cases.
Project Manager:	Scott Norwood

VI. COST ESTIMATE

GDS has developed a fixed price to provide all services sought in the RFP. The fixed price is based on our past experience with similar cases, our expectations regarding the amount of time each component will require, and our current fee schedule. The price for each component of the project is as follows:

COMPONENT	COST
1. Level of Investment	
Professional services fees	$12,500
2. Cost of Capital	
Professional services fees	$35,000
Travel expenses	1,500
3. Cost of Service	
Professional services fees	$32,500
Travel expenses	1,500
4. Rate Design	
Professional services fees	$15,000
Travel expenses	1,500
5. Depreciation Study	
Professional services fees	$35,000
Travel expenses	1,500
6. Additional necessary costs	
Copying, printing and postage	$1,000
Long distance telephone and fax	750
Data processing	750
Total Cost Estimate	
Professional services fees	$130,000
Travel Expenses	6,000
Additional costs	2,500
TOTAL	$138,500

The above cost estimates assume that there will be one technical hearing and that it will last for two consecutive days (October 7 and 8, 2002). The estimated travel expenses for each project component include the travel expenses for one expert to attend the technical hearing and include airfare, hotel, rental car and per diem expenses.

VII. CLIENT REFERENCES

Please refer to Section V.

ATTACHMENT
1

EDUCATION:

University of Texas at Austin
Bachelor of Arts in Journalism, 1975
Certified Public Accountant in Texas, February 1977

PROFESSIONAL MEMBERSHIPS

American Institute of Certified Public Accountants
Texas Society of Certified Public Accountants

EXPERIENCE

GDS Associates, Inc., March 2002 to present

Senior Project Manager of GDS Associates, Inc., Engineers and Consultants, Corpus Christi, Texas. Provides financial analysis for natural gas and electric markets; assists consumers in acquiring power needs in the competitive markets; provides analysis in gas, electric, telephone and water utility rate increase filings and presents expert testimony in regulatory proceedings on behalf of interveners. Issues addressed in testimony include all aspects of revenue requirement determination.

Independent Consultant, June 1982 to February 2002

Financial analysis for natural gas and electric markets; Provided analysis and expert witness testimony in gas, electric, telephone and water utility rate increase applications on behalf of interveners.

C. H. Guernsey & Co., Consulting Engineers & Architects, November 1980 - June 1982

Title: Regulatory Accountant and Financial Analyst

Duties included preparation of financial and accounting aspects of rate filings for electric cooperatives for presentation before the Public Utility Commission of Texas. Testified as an expert witness on accounting matters before the Public Utility Commission of Texas. Advised electric cooperatives on accounting and regulatory matters. Participated in review of rate increase applications of investor-owned utilities and prepared and presented expert witness testimony based on such review. Participated in special projects such as cost-benefit analyses related to owner participation in power plants and alternative regulatory treatments for nuclear generating stations.

Public Utility Commission of Texas, May 1977 - November 1980

Title: Chief Accountant III

Duties included providing expert witness testimony in investor-owned and cooperative telephone, electric and water utility rate cases filed with the Commission in the following areas: Fuel and purchased power, Operation and

maintenance expenses, Federal income taxes, Taxes other than federal income taxes, Affiliate transactions, Oil and gas exploration and development. Reviewed the books and business records of public utilities to determine the reasonableness of rate requests. Reviewed public utilities' implementation of fuel adjustment clause and other rate schedules to determine compliance with tariffs approved by Commission.

Sample List of Testimony Filed and participation in Regulatory Proceedings:

TXU Gas Distribution Application to Change Distribution Rates in its South Region on behalf of affected Texas municipalities, Fall 2002.

TXU Lone Star Pipeline Application to Change the City Gate Rate, Texas Railroad Commission Docket No. 8976 on behalf of the Aligned Cities, January 2000.

Santa Fe Pipeline Partnership, L.P., FERC Docket No. OR92-8-000, *et al* on behalf of Refinery Holding Company, L.P., January 1996.

Peoples Natural Gas Company, Rate Area Three on behalf of the Municipalities Served, December 1995.

Compliance review of Southern Union Gas Company's fuel cost recovery in the City of El Paso on behalf of the City of El Paso, Texas, Spring 1995.

Kansas Pipeline Partnership and Kansas Natural Partnership, Kansas Docket No. 190,362-U on behalf of Citizens' Utility Ratepayer Board, September 1994.

KN Energy, Inc., Kansas Corporation Commission Docket No. 186,363-U on behalf of Citizens' Utility Ratepayer Board, September 1993.

Peoples Natural Gas Company, Kansas Corporation Commission Docket No. 180,416-U, on behalf of the Citizens' Utility Ratepayer Board, August 1992.

Kansas Public Service Company, Kansas Corporation Commission Docket No. 179,484-U, on behalf of the Citizens' Utility Ratepayer Board, April 1992.

Greeley Gas Company, Kansas Corporation Commission Docket No. 177,142-U, on behalf of the Citizens' Utility Ratepayers Board, November 1991.

Peoples Natural Gas Company, Rate Areas Two and Three on behalf of the Municipalities Served, November 1991.

Southern Union Gas Company El Paso Service Area, Public Utility Regulatory Board of El Paso on behalf of the City of El Paso, November 1991.

Rio Grande Valley Gas Company, Texas Railroad Commission Docket No. 7604, Consolidated, on behalf of the Intervener Cities, May 1990.

Southern Union Gas Company El Paso Service Area, Public Utility Regulatory Board of El Paso on behalf of the City of El Paso, October 1990.

Rio Grande Valley Gas Company, Texas Railroad Commission Docket No. 4717, 1984 and Docket No. 3858, on behalf of the Rio Grande Valley Cities, March 1982.

Reliant Energy HL&P Application for Approval of Unbundled Cost of Service Rates, Texas PUC Docket No. 22355 on behalf of the City of Houston and the Coalition of Cities, December 2000.

TXU Electric Company Application for Approval of Unbundled Cost of Service Rates, Texas PUC Docket No. 22350 on behalf of the Office of Public Utility Counsel, October 2000.

Texas-New Mexico Power Company Application for Approval of Unbundled Cost of Service Rates, Texas PUC Docket No. 22349 on behalf of the Office of Public Utility Counsel, January 2001.

Houston Lighting and Power Company, Texas PUC Docket No. 12065 on behalf of Office of Public Utility Counsel, November 1994.

El Paso Electric Company, Texas PUC Docket No. 12700 on behalf of Office of Public Utility Counsel and The City of El Paso, Texas, June 1994.

Application of Central and South West Corporation and El Paso Electric Company For Approval of Acquisition, PUC Docket No. 12700 on behalf of Office of Public Utility Counsel, June 1994.

El Paso Electric Company, Public Utility Regulation Board of The City of El Paso, Texas on behalf of the City of El Paso, Texas, May 1994.

City of Austin Water and Wastewater Utility before City Counsel on behalf of residential and small commercial ratepayers, October 1993.

Texas Utilities Electric Company, Texas PUC Docket No. 11735 on behalf of Certain Cities Served by Texas Utilities Electric Company, September 1993.

Complaint of General Counsel against Cherokee County Electric Cooperative, Inc. regarding application of Cherokee's switchover tariff, Texas PUC Docket No. 11351, on behalf of the Cooperative, June 1993.

Texas Utilities Electric Company, Texas PUC Docket No. 11735 on behalf of the Office of Public Utility Counsel, April 1993.

Application of Entergy Corporation and GSU for Sale, Transfer or Merger, Texas PUC Docket No. 11292, on behalf of Office of Public Utility Counsel, January 1993.

Complaint of NBC Telecommunications, Inc. against Southwestern Bell Telephone Company, Texas PUC Docket No. 10762, on behalf of complainant, September 1992.
Central Texas Telephone Company, Texas PUC Docket No. 9981, on behalf of the Office of Public Utility Counsel, December 1991.

Texas-New Mexico Power Company, Texas PUC Docket No. 10200, on behalf of the Office of Public Utility Counsel, December 1991.

City of Round Rock, Texas Water Commission Docket No. 8600-M, on behalf of Brushy Creek Municipal Utility District, October 1991.

El Paso Electric Company, Texas PUC Docket No. 9945, on behalf of the Office of Public Utility Counsel, April 1991.

Houston Lighting & Power Company, Texas PUC Docket No. 9850, on behalf of the Office of Public Utility Counsel, February 1991.

Greeley Gas Company, Kansas Corporation Commission Docket No. 170,588-U, on behalf of the Citizens' Utility Ratepayers Board, August 1990.

Texas Utilities Electric Company, Texas PUC Docket No. 9300, on behalf of the Intervener Cities, April 1990.

Gulf States Utilities Company, Texas PUC Docket No. 8702, on behalf of the Intervener Cities, July 1989.

Central Power & Light Company, Texas PUC Docket No. 8646, on behalf of the Intervener Cities, June 1989.

Lower Colorado River Authority, Texas PUC Docket No. 8400, on behalf of several wholesale customers, February 1989.

Lower Colorado River Authority, Texas PUC Docket No. 8032, on behalf of several wholesale customers, June 1988.

Tawakoni Water Utility Corporation, Texas Water Commission Docket No. 7368-R, on behalf of Tawakoni Water Consumers Association, January 1988.

Hill Country Waterworks Company, Texas Water Commission Docket No. 172-W, on behalf of the City of Hill Country Village and the City of Hollywood Park, July 1987.

Detroit Edison Company, Michigan PSC, Case No. U-8683, on behalf of North Star Steel Michigan, May 1987.

Gulf States Utilities Company, Texas PUC Docket No. 7195, on behalf of North Star Steel Texas, January 1987.

Mustang Telephone Company, Texas PUC Docket No. 6635, July 1986, on behalf of intervener cities.

Lower Colorado River Authority, Texas PUC Docket No. 6027, on behalf of several wholesale customers, March 1985.

Fannin County Electric Cooperative, Texas PUC Docket No. 4940, on behalf of the Cooperative.

Dewitt County Electric Cooperative, Texas PUC Docket No. 4919, on behalf of the Cooperative.

Houston Lighting and Power Company, Texas PUC Docket No. 4540, August 1982, on behalf of the City of Houston.

Houston Lighting & Power Company, Texas PUC Docket No. 3320, September 1980, on behalf of the Texas Public Utility Commission.

Inquiry by Public Utility Commission of Texas into Certain Affiliate transactions of Texas Electric Service Company , Texas Power and Light Company and Dallas Power and light Company, Texas PUC Docket Nos. 1517, 1813 and 1903, February 1979, on behalf of the Texas Public Utility Commission.

EDUCATION: Master of Business Administration, Georgia State University, 1990
Concentration: Finance and Decision Sciences
Bachelor of Business Administration, The University of Texas at Austin, 1978.
Concentration: Statistics and Operations Research

PROFESSIONAL MEMBERSHIP: American Statistical Association (ASA)

EXPERIENCE:

1986-Present GDS Associates, Inc.

Responsibilities include the direction of statistical services provided by GDS and supervision of supporting project staff. Areas of expertise include long-term and short-term forecasting, sample design, consumer surveys, load research, weather normalization, database management, and decision support systems.

1980-1986 Southern Engineering Company

Responsibilities included participation and project management of projects focusing on statistical applications, including load forecasts and consumer surveys.

Specific Project Experience Includes:

Designed, implemented and currently manages load forecasting systems for thirteen electric utilities in Texas. Forecasting systems provide long-term (15 year) and short-term (12-month) forecasts for resource and financial planning and are supported by a network of econometric and end-use models. Consumer attitude and appliance stock surveys are conducted every three years. Outputs of the system include load forecast reports, consumer surveys, oral/written testimony, and documentation to regulatory agencies.

Developed and implemented an electric load forecasting system for the Public Service Authority of South Carolina. Short-term models were based on ARIMA techniques, and long-term models were developed using both econometric (SAS software) and end-use models (EPRI's REEPS model, Residential End-Use Energy Planning System). Project highlights included: (i) extensive data collection and development of the end use model, and (ii) on-site industrial customer interviews.

Developed load forecasts for electric utility systems in Alabama, Alaska, Georgia, Kentucky, Illinois, Indiana, Mississippi, North Carolina, Ohio, South Carolina, Texas, and Virginia. Methodologies included econometric modeling, end-use modeling, trending, and delphi techniques.

Currently manages ongoing consulting services to an Atlanta, Georgia based marketing services firm in applications regarding consumer research in the retail industry. Primary areas of service focus on project management, statistical issues and analytical expertise regarding consumer surveys. Specific services provided include: definition of consumer market trade areas,

development of survey questionnaires, implementation of data processing procedures, development of sampling methodology, interpretation of survey results, and preparation of final survey reports. Developed a process for merging economic/demographic data (sources: U.S. Census and Bureau of Economic Analysis) with survey data. Developed models used to estimate average consumer expenditure in response to influential characteristics, including: area of residence, average household income, age, and gender.

Managed residential consumer survey projects for utilities in Texas, South Carolina, and Alabama. Developed questionnaire, identified population frame, designed sample, validated responses, tabulated results, and documented conclusions and methodology. Developed applications software to select stratified random sample (Dalenius/Hodges and optimum allocation), produce mailing labels, tabulate responses, and calculate confidence bands by stratum and by total sample. Software was developed using the Statistical Analysis System (SAS) software package.

Provided consumer survey services to a Marietta, Georgia based consulting firm for a series of surveys administered to banking customers at branches located throughout the north Georgia area. Provided cross-tabulations of survey results, developed local demographic and economic profiles of households located in the branch areas, and created indexes as a means of comparing banking customers to the general population.

Presented expert testimony before the Georgia Public Service Commission on behalf of the Staff Adversary team. Testimony addressed issues regarding Georgia Power Company's Load and Energy Forecast filed with the company's 1998 and 2001 Integrated Resource Plans.

Presented expert testimony before the Michigan Public Service Commission on behalf of the state of Michigan, Office of the Attorney General. Testimony addressed the review, conclusions and recommendations regarding the load forecast presented by Consumers Power Company.

Presented expert testimony before the Public Utility Commission of Texas on behalf of Wood County Electric Cooperative. Testimony addressed the defense of load research results utilized in the cooperative's rate filing.

Conducted load research for ten electric cooperatives in Texas. Project involved sample design, sample selection, translation of pulse data, computation of class CP and NCP estimates, and development of relationship between class NCP and kWh sales. Results provided input for cost of service and rate design studies.

TRAINING SEMINARS CONDUCTED:

1. Load Forecasting Techniques: Georgia Public Service Commission Staff
2. Econometric Modeling using SAS: Public Service Authority of South Carolina
3. Customer Surveys in the Retail Industry: Morris & Fellows, Inc.

SOFTWARE EXPERTISE:

Statistical Analysis System (SAS),
Microsoft Office Products
MetrixND
EPRI Residential End-Use Energy Planning System (REEPS),
Energy 2020,
Micro TSP,
Lotus 1-2-3,
@Risk

FILED TESTIMONY:

Georgia Public Service Commission
Michigan Public Service Commission
Texas Public Utility Commission

EDUCATION: Bachelor of Science, Economics, Georgia Institute of Technology, 1973
Post Graduate Work in Accounting, Georgia State University, 1974

EXPERIENCE:

Mr. Daniel has over twenty-five years of experience in the natural gas, electric, water and telecommunications utility industries. As manager of GDS Associates, Inc.'s Texas District Office, he has both administrative and project management responsibilities. The administrative duties involve personnel management, staffing, strategic planning, service development and marketing. A description of examples of his prior client project responsibilities follows.

1986-Present GDS Associates, Inc.:

Vice President and Manager, Texas Office of GDS Associates, Inc., Engineers and Consultants, Austin, Texas. Provides analysis of natural gas, electric, telephone and water utility rate increase filings and presents expert testimony in regulatory proceedings on behalf of intervenors. Issues addressed in testimony include revenue requirements, cost allocation, and rate design. Other project responsibilities involving rate expertise include the preparation of rate studies for publicly-owned utilities. In the energy procurement area, Mr. Daniel provides electric and gas procurement assistance, including the preparation of RFPs, the analysis of supply and delivery proposals, and contract negotiations with investor-owned utilities on behalf of various wholesale and retail customers. Additional experience in load management and energy conservation studies, power requirements studies, and economic analysis of alternate power supply sources.

1983-1986 Southern Engineering Company:

Manager, District Office of Southern Engineering Company, Austin, Texas. Provided expert testimony before various regulatory agencies on issues related to utility rate design, cost allocation, revenue requirements, and utility economics. Prepared comments on generic rulemaking issues before regulatory agencies and presented ratemaking seminars or courses before various organizations. Also involved in power supply negotiations, litigation support, rate studies for publicly-owned utilities and energy conservation studies.

1979-1983 R.W. Beck and Associates:

Supervising Analyst, R.W. Beck and Associates, Phoenix, Arizona. Prepared rate studies for publicly-owned electric, gas, water and wastewater utilities, including the development of revenue requirement studies, cost of service

studies, and rate design studies. Also presented expert rate testimony before various regulatory commissions on behalf of utility customers. Additional experience in the preparation of municipal utility bond financing feasibility studies.

1974-1979 Southern Engineering Company:

Consultant, Southern Engineering Company, Atlanta, Georgia. Analyzed utility rate increase applications and presented expert testimony on behalf of utility customers. Also developed economic analysis of alternate power supply sources and generation and transmission feasibility studies.

Specific Project Experience:

James W. Daniel has conducted technical economic analyses of gas, electric, telephone, water and wastewater cases involving over 45 investor-owned utilities and 20 publicly-owned utilities in 25 states. Presentation of expert testimony has been made by Mr. Daniel before the following regulatory commissions: Federal Energy Regulatory Commission; Public Utility Commission of Texas; Texas Natural Resource Conservation Commission, the Railroad Commission of Texas, Arizona Corporation Commission; South Dakota Public Utility Commission; New Mexico Public Service Commission; Louisiana Public Service Commission; State Corporation Commission of Kansas; Arkansas Public Service Commission; and the Illinois Commerce Commission. He has also presented testimony at public hearings and at the Condemnation Court Appointed by the Supreme Court of Nebraska. Mr. Daniel has submitted an expert opinion report before the United States Tax Court. In addition, Mr. Daniel has presented utility ratemaking training seminars and has presented utility related workshops for the National Rural Electric Cooperative Association. The following is a list of utility related proceedings in which Mr. Daniel presented expert testimony and/or analysis:

Texas Utilities Company Lone Star Pipeline, before the Texas Railroad Commission in GUD Docket No. 8976, on behalf of the City of Denton, et.al, 2000.

Peoples Natural Gas Company, before the Condemnation Court Appointed by the Supreme Court of Nebraska in Docket No. 101, on behalf of the City of Scribner, Nebraska, 1998.

Peoples Natural Gas Company, before the Condemnation Court Appointed by the Supreme Court of Nebraska in Docket No. 13880, on behalf of the City of Wahoo, Nebraska, 1997.

Peoples Natural Gas Company, before PNG's Rate Area Three Municipalities, on behalf of 90 Nebraska municipalities, 1995.

ENSTAR Natural Gas Company, before the Alaska Public Utilities Commission, on behalf of Elmendorf Air Force Base, 1986.

Lykes Energy, Inc., before the United States Tax Court in Dockets No. 7685-96 and 4979-97 on behalf of the Internal Revenue Service, 1997.

Arkansas Western Gas Company, before the Arkansas Public Service Commission in Docket No. 97-019-U on behalf of the Office of Arkansas Attorney General, 1997.

Houston Lighting & Power Company, Texas PUC Docket No. 9850, on behalf of the Coalition of Cities, 1990-91.

Sharyland Utilities, L.P., before the Texas Public Utility Commission in Docket No. 22348, on behalf of Sharyland Utilities, L.P., 2000.

Sharyland Utilities, L.P., before the Texas Public Utility Commission in Docket No. 21591, on behalf of Sharyland Utilities, L.P., 1999.

Central Power and Light Company, before the Texas Public Utility Commission in Docket No. 21528, on behalf of Texas Retailers Association and Texas Hospital Association, 1999.

Central and South West Corporation and American Electric Power Company, Inc., Texas PUC Docket No. 19265, on behalf of the East Texas Cooperatives, 1999.

Sharyland Utilities, L.P., before the Texas Public Utility Commission in Docket No. 20292, on behalf of Sharyland Utilities, L.P, 1998.

Entergy Gulf States, Inc., before the Federal Energy Regulatory Commission in Docket No. EL-99-6-000, on behalf of Sam Rayburn G&T, Inc., 1998.

Entergy Texas, before the Texas Public Utility Commission in Docket No. 16705 on behalf of High Load Factor Commercial Customer Group, 1997.

Longbranch Associates, L.P. dba Coppertree Apartments, before the Texas Natural Resource Conservation Commission in Docket No. 96-0652-UCR on behalf of the City of Houston, Texas, 1996.

Texas Utilities Electric Company, before the Texas Public Utility Commission in Docket No. 15638 on behalf of Tex-La Electric Cooperative of Texas, Inc., 1996.

Central Power and Light Company and West Texas Utilities Company, before the Texas Public Utility Commission in Docket No. 15643 on behalf of Rio Grande Electric Cooperative, Inc., 1996.

Commonwealth Edison Company, before the State of Illinois Commerce Commission in Dockets No. 96-0245 & 96-0248 on behalf of the Citizens Utility Board, the City of Chicago, Illinois, and the Office of the Attorney General, 1996.

Public Utility Commission, before the Texas Public Utility Commission in Docket No. 15296 on behalf of the City of Bryan, Texas, 1996.

City of Bryan, Texas, before the Texas Public Utility Commission in Docket No. 15766 on behalf of the City of Bryan, Texas, 1996.

Central Power and Light Company, before the Texas Public Utility Commission in Docket No. 14965 on behalf of H. E. Butt Grocery Company, 1996.

City of College Station, Texas, before the Federal Energy Regulatory Commission in Docket No. TX96-2-000 on behalf of the City of Bryan, Texas, 1996.

Southwestern Electric Power Company, before the Texas Public Utility Commission in Docket No. 14435 on behalf of Northeast Texas Electric Cooperative, Inc., and Upshur-Rural Cooperative, Inc., 1995.

West Texas Utilities Company, before the Texas Public Utility Commission in Docket No. 13369 on behalf of the City of San Angelo, Texas, 1995.

Houston Lighting and Power Company, before the Texas Public Utility Commission in Docket No. 12065 on behalf of the City of Houston, Texas, 1995.

Central Power and Light Company, before the Texas Public Utility Commission in Docket No. 12820 on behalf of H. E. Butt Grocery Company, 1994.

Kansas Natural Pipeline and Kansas Natural Partnership, before the Kansas Corporation Commission in Docket No. 190-362-U on behalf of Citizen's Utility Ratepayer Board, 1994.

KN Energy, Inc., before the Kansas Corporation Commission in Docket No. 186-363-U on behalf of Citizens' Utility Ratepayer Board in a natural gas rate case, 1994.

Lower Colorado River Authority, Texas PUC Docket No. 9427, on behalf of New Braunfels Utilities, Guadalupe Valley Electric Cooperative, Inc., DeWitt County Electric Cooperative, Inc., San Bernard Electric Cooperative, Inc., 1990.

Central Power and Light Company, Texas PUC Docket No. 9561, on behalf of South Texas Cotton Ginners, 1990.

El Paso Electric Company, Texas PUC Docket No. 9165, on behalf of El Paso Community College, 1990.

Texas Utilities Electric Company, Texas PUC Docket No. 9300, 1990; Docket No. 6677, 1986; Docket No. 5640, 1984; on behalf of Tex-La Electric Cooperative of Texas, Inc.

Lower Colorado River Authority, Texas PUC Docket No. 8032, on behalf of Guadalupe Valley Electric Cooperative, Inc. 1988.

Peoples Natural Gas Company, before PNG's Rate Area Two and Three Municipalities, on behalf of 33 Nebraska municipalities, 1991-1992.

Central Louisiana Electric Company, Louisiana Public Service Commission Docket No. U-16150, on behalf of England Air Force Base and the Federal Executive Agencies, 1986.

Gulf States Utilities Company, Federal Energy Regulatory Commission Docket No. ER85-538-001, on behalf of Cajun Electric Power Cooperative, Inc., Sam Rayburn G&T, Inc., Sam Rayburn Municipal Power Agency, and Louisiana Energy and Power Authority, 1985.

Texas Utilities Electric Company, Texas PUC Docket No. 5709, Rusk County Electric Cooperative, Inc. 1984.

Gulf States Utilities Company, Texas PUC Docket No. 5560, on behalf of North Star Steel Texas, Inc., 1984.

Texas Power & Light Company, Texas PUC Docket No. 5294, on behalf of Tex-La Electric Cooperative of Texas, Inc. 1983.

Arizona Public Service Company, FERC Docket No. ER81-179, on behalf of Electrical District No. 6, Roosevelt Irrigation District, Maricopa County Water Conservation District, Electrical District No. 3, Buckeye Water Conservation & Drainage District No. 7, Arizona Power Electrical District No. 1, 1981.

Citizens Utilities Company, Arizona Corporation Commission Docket No. 9962-E-1032 (Phase II), on behalf of GK Technologies, Inc. and McCulloch, Corp., 1980.

Public Service Company of Indiana, Federal Energy Regulatory Commission Docket No. ER78-153, on behalf of Wabash Valley Power Association, Inc., 1980.

Northwestern Public Service Company, South Dakota Public Utilities Commission Docket No. F-3055, on behalf of the Commission staff.

REGULATORY EXPERIENCE:

Mr. Daniel has presented expert reports and/or testimony and exhibits in rate and cost-of-service matters before the following regulatory commissions or courts:

Arizona Corporation Commission
Arkansas Public Service Commission
Condemnation Court Appointed by the Supreme Court of Nebraska
Illinois Commerce Commission
Kansas Corporation Commission
Louisiana Public Service Commission
Nebraska Municipality Rate Area
New Mexico Public Service Commission
Public Utility Commission of Texas
Railroad Commission of Texas
South Dakota Public Utility Commission
Texas Natural Resource Conservation Commission
United States Tax Court
Federal Energy Regulatory Commission
(Formerly Federal Power Commission)

EDUCATION: Master of Business Administration - Finance, Georgia State University, 1973
Bachelor of Industrial Management, Georgia Institute of Technology, 1972

EXPERIENCE:

Mr. Solomon has extensive experience in electric utility ratemaking and power supply contracting. This broad experience includes projected future power cost and power supply analysis; allocated cost-of-service and rate design analysis; revenue requirements and rate of return analysis; avoided cost analysis, presentation of expert testimony before the Federal Energy Regulatory Commission in wholesale rate cases and before state utility commissions in wholesale and retail rate cases, least cost integrated resource planning and certificate of convenience proceedings; negotiation of wholesale and retail full requirements, partial requirements, economic development, interruptible, and transmission rates and contracts; preparation and presentation of depreciation studies; analysis of management audits of electric utilities; preparation and evaluation of merger and acquisition analyses; participation in bankruptcy proceedings; and valuation of electric utility distribution systems.

Mr. Solomon has also been heavily involved in assisting clients in the electric industry restructuring process. He has participated in evaluating, negotiating and testifying on independent system operator/regional transmission organization ("ISO/RTO") formation and implementation and other industry restructuring issues. He has experience with the PJM ISO, New York ISO, Midwest ISO, Alliance RTO formation and has been actively involved in the Cincinnati RTO collaborative process since its initiation by FERC Order No. 2000. In addition, Mr. Solomon has testified in industry restructuring proceedings in Virginia, Arkansas, Texas and Ohio.

Mr. Solomon was employed by Southern Engineering Company from January 1975 until February 1986. While at Southern Engineering, Mr. Solomon provided electric utility ratemaking services to rural electric cooperatives, municipally-owned utilities, large industrial firms, and governmental agencies advancing from rate analyst to Assistant Vice President, Economic and Regulatory Services. In February 1986, Mr. Solomon participated in the founding of GDS Associates, Inc. where he continues to provide regulatory consulting services, expert testimony on electric and gas utility pricing and service matters, and power supply contracting services.

Mr. Solomon has presented expert testimony before numerous regulatory bodies in the following areas: the cost of capital and required rate of return for both privately-owned and publicly-owned utilities; accounting as applied in ratemaking and the effects of appropriate alternative accounting methods on expenses, income taxes, revenues, rate base and cost of capital; proper methods of cost allocation; proper methods of measuring working capital requirements; the proper development of test year revenue requirements; rate design; least cost integrated resource planning; industry restructuring issues; stranded cost analysis; and the development of competitive electricity markets through properly designed ISOs, Transcos and RTOs.

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(770) 426-0303 - Fax
Butch.Solomon@GDSAssociates.com - E-Mail

Mr. Solomon has testified extensively before the Federal Energy Regulatory Commission (formerly Federal Power Commission) in proceedings involving full and partial requirements wholesale rates and terms and conditions of service, mergers and acquisitions, market-based rate applications, regional restructuring and implementation of an ISO and energy exchange, transmission rates and service terms, coordination service rates, service reliability, fuel adjustment provisions, customer filed complaints and special accounting dockets. Mr. Solomon has also testified before the Arkansas Public Service Commission, the Florida Public Service Commission, the Georgia Public Service Commission, the Public Service Commission of Indiana, the Kentucky Public Service Commission, the Maine Public Utilities Commission, the Michigan Public Service Commission, the Public Utilities Commission of Minnesota, the Nevada Public Utilities Commission, the New Jersey Board of Public Utilities, the North Carolina Utilities Commission, the Public Utilities Commission of Ohio, the Pennsylvania Public Utility Commission, the Public Utilities Commission of the State of Rhode Island, the Public Utility Commission of Texas, and the Virginia State Corporation Commission in matters similar to those before the FERC plus the appropriate costing and design of interruptible, economic development and special contract rates and prudent integrated resource planning practices. In addition, Mr. Solomon has participated in the successful negotiation of settlements in many cases thereby eliminating the requirement for the filing of testimony.

In addition to filing expert testimony, Mr. Solomon has participated in the preparation of comments for submission to the FERC and state regulatory commissions in generic rulemaking proceedings on the following subjects: income tax normalization; changes to FERC Form 1; rate of return on common equity; CWIP in rate base; interest rate on refunds; treatment of captive fuel operations; cash working capital; changes in filing requirements; price squeeze; and pricing of electricity sales.

Additionally, Mr. Solomon has testified before the U.S. Senate Committee on Energy and Natural Resources, Subcommittee on Energy Regulation concerning the "Construction Work in Progress Policy Act of 1983" (S.817 and S.1069) and before the Utilities Committee of the Mississippi House of Representatives regarding valuation of electric distribution systems.

EDUCATION: Georgia Southern University; BBA, Management, 1966-1970
Woodrow Wilson College of Law; JD, 1972-1975
Certified Public Accountant, 1987

PROFESSIONAL MEMBERSHIPS: American Institute of Certified Public Accountants
Georgia Society of Certified Public Accountants
Society of Depreciation Professionals

EXPERIENCE:

Mr. Cook has extensive experience in the electric utility industry. This experience includes preparation of cost of service studies and revenue requirements analysis; development of depreciation studies, development of rate study models, preparation of merger studies, cost of capital analysis and negotiation of wholesale and retail revenue requirements and rates.

Mr. Cook was employed by Ebasco Business Consulting Company from March 1978 through June 1982. While at Ebasco Mr. Cook served as Project Manager in the utility rates division where he provided cost of service, revenue requirements and FERC reporting services to investor-owned and municipal electric utilities. In June 1982 Mr. Cook joined Southern Engineering Company as a Project Manager where he continued to provide cost of service and revenue requirements assistance to rural electric cooperative and municipal electric utilities. In February 1986 Mr. Cook joined GDS Associates, Inc. where he has served as Senior Project Manager. He has provided cost of service, revenue requirements, depreciation analysis, mergers and acquisitions studies, FERC and state reporting and other ratemaking services to electric cooperative, municipal, industrial and governmental organizations. Mr. Cook has also provided electric rate negotiation services on behalf of electric utilities.

Mr. Cook has prepared testimony and has testified before several regulatory agencies. Mr. Cook has filed testimony regarding the preparation of utilities' cost of service, o & m expenses, depreciation, taxes other than income taxes, a & g expenses, other revenues, income taxes and rate base on behalf of various electric utility clients. Mr. Cook has testified before the Georgia Public Service Commission, the Texas Public Utilities Commission and the Alaska Regulatory Commission. Mr. Cook has also participated in the filing of comments regarding generic ratemaking dockets including, Construction Work in Progress (CWIP), cash working capital and return on common equity.

Specific Project Experience Includes:

Prepared 1997 cost of service analyses regarding Cleveland Electric Illuminating Company on behalf of Cleveland Public Power.

Reviewed and prepared cost of service analyses regarding 1997 Southern Company open access transmission filing on behalf of Southeastern Federal Power Customers, Inc.

Reviewed and analyzed Florida Power & Light Company's 1997 depreciation filing on behalf of Seminole Electric Cooperative, Inc.

Prepared 1997 transmission rate cost of service analyses regarding South Carolina Electric & Gas Company on behalf of Southeastern Federal Power Customers, Inc.

Prepared 1997 cost of service analyses of Western Resources/KCPL merger filing on behalf of Kansas Electric Power Cooperative.

Prepared 1997 analyses of SEPCo's depreciation rate study on behalf of Georgia Public Service Commission.

Provided 1998 cost of service and rate assistance to Georgia Public Service Commission regarding Georgia Power Company retail rate filing.

Provided 1999 litigation support and analysis on behalf of Niagara Mohawk Power in counterclaim regarding Baesha Engineering Associates.

Provided 1999 cost of service and rate analysis assistance to Southeastern Federal Power Customers regarding SEPA/TVA proposed rate increases. Reviewed and provided recommendations regarding reasonableness of costs.

Prepared 2000 testimony regarding depreciation issue in Reliant HL&P filing on behalf of City of Houston and others. Provided 2001 testimony on behalf of City of Houston at retail rate proceeding.

Prepared 2000 testimony regarding appropriate administrative & general expense of Chugach Electric Association 1997 revenue requirements study on behalf of Matanuska Electric Association. Provided 2001 testimony on behalf of Matanuska at rate proceeding

Prepared 2000 testimony regarding recommended revenue requirements and wholesale cost of service of Pennsylvania Electric Company on behalf of Allegheny Electric Cooperative, Inc.

Prepared 2001 testimony regarding appropriate administrative & general expense of Chugach Electric Association 1998 revenue requirements study on behalf of Matanuska Electric Association.

EDUCATION: AAS, Petroleum Technology, Bee County College, Beeville, Texas
Our Lady of the Lake University, San Antonio, Texas
U.S. Department of Transportation Safety Institute, Oklahoma City, OK

PROFESSIONAL MEMBERSHIPS:

Texas Gas Association (TGA)
American Public Gas Association
American Gas Association
Past Director, TGA
Past Chairman, TGA Distribution Committee
Chairman, TGA Membership Committee
Chairman, TGA Scholarship & Community Affairs Committee

EXPERIENCE:

Over seventeen years of experience in operations, financial, construction, marketing, customer service, regulatory compliance and training for the natural gas pipeline industry. Currently a natural gas consultant/project manager for the Cities of Brady, Castroville, Corpus Christi, Dilley, Port Aransas, and Starr County Gas System, gas gathering companies, GDS Associates, Inc., Universal Ensco, Inc., Pipeline Accident Prevention Service and the Texas A & M University System. Have taken special courses in pipeline safety regulations-application and enforcement of pipeline systems, business, and management. Received the Outstanding Service Award to the Railroad Commission of Texas in 1987, the Texas Gas Association Service (TGA) Award in 1995, 1996, 1999, and 2000 and Distinguished TGA Carrying the Flame Award in 1996 for outstanding contributions to the natural gas industry. Bilingual in Spanish.

Present GDS Associates, Inc.

Senior Project Manager/Consultant, GDS Associates, Inc. Currently assisting the Navigant/GDS Team in conducting a Utility Privatization Study for the Department of Navy. The study consists of evaluating existing inventory, operations, maintaining, capital improvements data, and to create a replacement cost for natural gas and other utilities on a 25-year life cycle for the purpose of future privatization consideration. The Bases that have been evaluated are: USMC, Barstow, California; USMC, Yuma, Arizona; Naval Bases, NAWS & CBC, Ventura County, California; and NPS, Monterey, California. Project Manager on a City of Dilley rate adjustment study. Project Manager on a regulatory review for the Cities of Port Aransas, Castroville, Dilley and Bay City Gas Company. Project Consultant on a Cost of Service Study for the Cities of Westfield, CN and Dilley, TX. Project Manager on creating an energy procurement strategy for the Cities of Chicago, Illinois and Corpus Christi, Texas. Project Manager in gas supply contracts negotations for the Cities of Dilley and Port Aransas, Texas. Conducted research and development of operator qualifications program with Pipeline Accident Prevention Service. Project

Consultant in a review of fixed price option by Peoples Gas to the City of Norfolk, Nebraska. Project Manager on a system lost and unaccounted investigation for the City of Cotulla, Texas.

1997- 2001 Peña & Associates

Natural Gas Consultant, Peña & Associates. Assisting various gas distribution (public/private) and transmission companies throughout Texas in their dealing with issues concerning operations, construction, marketing, training and regulatory compliance. Served as an expert witness for Griggs & Harrison, Houston, Texas. An advisor and instructor to the Texas A & M University System's Engineering Extension Service, Public Sector Division, Pipeline Operator Qualification Program. Provide consulting services to Universal Ensco, Inc., a pipeline-engineering firm conducting pipeline evaluations on military Bases. Providing Training services for the Texas Gas Association and Pipeline Accident Prevention Service members/clients.

1997-1999 Pipeline Accident Prevention Service (PAPS)

Director, Business Development, Pipeline Accident Prevention Service (PAPS). Worked in the development of PAPS and consulting. PAPS is a consulting, training, and field service provider in the natural gas pipeline industry. Provide training and consulting services for Gas Natural del noroeste in Hermosillo, Sonora, Mexico and Igasamex, Integrated Gas Services De Mexico, Mexico City, Mexico.

1989-1997 Gulfside Industries Ltd.

Executive Vice President and Director, Gulfside Industries Ltd., Somerset, Texas. Managed the operations and administration of a natural gas utility in South Texas with approximately 2600 meters for 7 ½ years. President of Paladin Resources, Inc., a wholly owned subsidiary Oil and Gas Production Company of Gulfside for 2 ½ years.

1984-1989 Texas Railroad Commission

Engineering Technician IV, Transportation/Gas Utilities Division, Pipeline Safety Section for the Railroad Commission of Texas for 5 years. Performed routine technical work relating to pipeline safety and compliance for the Pipeline Safety Section of the Transportation/Gas Utilities Division. Conducted routine safety evaluations, accident and special investigations, responded to emergency situations, prepared necessary reports and completed administrative functions for gas distribution and transmission systems, small and major. Served on the training committee and was an instructor in Commission seminars and workshops.

1982-1984 City of George West, Texas

Gas Technician, City of George West, Texas. Studied and suggested improvements for gas system.

1980-1994 Independent Contractor

Self Employed Contract Gauger, Independent Contractor. Gauged natural gas and oil well production.

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(512) 494-0205 - Fax
simon.pena@gdsassociates.com

EDUCATION: BBA Accounting, University of Texas at Austin
Certified Public Accountant, Texas

PROFESSIONAL MEMBERSHIPS: National Association of Water Companies
Texas Society of Certified Professional Accountants

EXPERIENCE:

Mr. Loy has over 20 years experience in Public Utility regulation and financial matters.

2001-Present GDS Associates, Inc.: Sr. Project Manager – Mr Loy started with GDS in June of 2001. His focus is on regulatory accounting and finance. He is experienced in electric, gas, water, and wastewater regulatory and accounting matters. While at GDS, Mr. Loy has assisted with the financial analysis of purchase power and aggregation projects as a result of the recent deregulation of the electric industry in Texas. Further, he assisted in the analysis of the TXU Gas Distribution South Region Rate Case filed before various municipalities in Texas.

1999-2001 AquaSource Inc.: General Manager Rates and Regulatory Affairs - AquaSource Inc., a wholly owned subsidiary of DQE Inc and parent of Duquesne Light. AquaSource was formed in 1997 to take advantage of the consolidation in the water and wastewater industries and spent three years and more than $400 million acquiring water and wastewater companies.

Mr Loy's duties included directing the compilation and filing of rate cases, acquisition analyses and related filings, commission staff relations, and governmental relations in the twelve states in which AquaSource operates. Additionally, he supervised a professional staff located throughout the country and assisted in business development, contract negotiations and other special projects.

His appointment came in the middle of AquaSource's aggressive acquisition phase. Accordingly, his first year was spent primarily working to clean up a very chaotic regulatory environment. In so doing, he introduced order and process where before there was none.

1993-1999 Citizens Utilities Company: Manager, Regulatory Affairs – Mr. Loy served as Project Manager of four multiple-company rate case filings, including two in Ohio, six in Illinois, five in Pennsylvania and six in Arizona. In those cases, he prepared and presented testimony, developed revenue requirement calculations, generated revenue and expense pro forma adjustments, performed working capital lead/lag studies, and evaluated rate design/cost of service issues. He proposed surcharge mechanisms for purchased water, a reverse osmosis process, and

contract waste treatment. Additionally, Mr. Loy designed and directed the development of the multiple company revenue requirement models that generated filing schedules. In the fall of 1997, Citizens promoted Mr. Loy to Manager Regulatory Affairs, after which he reported to the Vice President of Regulatory Affairs. In the new position, he supervised the staff responsible for all regulatory activity involving gas, electric and water/wastewater in ten states. The last project he was involved with before leaving Citizens was planning and directing the preparation of a rate filing for the Company's electric distribution system in Vermont

Other Accomplishments and Relevant Experience:

- Played a key role in the acquisition of three water and wastewater companies and their inclusion in the rate case of three other Citizens companies.
- Analyzed several likely municipal and private acquisitions, and developed and analyzed cash flow forecasts to determine their value and potential. These projects included evaluating a trade of Citizens wastewater treatment plants for a municipal water system.
- Directed a team of accountants assembled to develop common accounting procedures for the Arizona, Illinois, Indiana, Ohio and Pennsylvania water/wastewater properties. This helped position the company to compete more efficiently in the unregulated O&M contract business.
- Developed the accounting and regulatory strategy for Citizens Public Works Services Company, a wholly owned unregulated subsidiary involved in the O&M contract business. The treatment established accounting for future projects and precedents for future commission decisions regarding affiliated transactions with unregulated subsidiaries.
- Contributed to project with Citizen's Lake Michigan pipeline that was seeking an unregulated status. This was the first privately-owned water pipeline of its kind in a major metropolitan market.
- Key contributor on a team which successfully competed with other major utilities and O&M companies for a major water/wastewater franchise serving 12,000+ customers in the Phoenix area. Mr. Loy worked in developing the proposal, actively participated in the final negotiations, and prepared the regulatory filings.
- Mr. Loy served on a team that developed the accounting and regulatory strategy for the implementation of Citizens Business Service Company, a wholly owned unregulated subsidiary.

1989-1993 Southern Union Gas Company: Rate Manager – Mr. Loy joined Southern Union as Sr. Internal Auditor. In that capacity, he contributed to multiple projects pertaining to the upcoming merger with a large publicly traded corporation. These projects included supervising audits of gas purchases, accounts receivable,

accounts payable and oil and gas holdings. He was promoted to Rate Manager reporting to the Vice President of Regulatory Affairs. In that capacity, he supervised a team of four directing the preparation and implementation of 16 rate increase applications before various municipal and state regulatory bodies, and led negotiating sessions with elected and municipal officials. Under Mr. Loy's direction, the Regulatory Affairs Department reduced the preparation time of rate applications from approximately 6 months to 8 weeks.

Other Accomplishments and Relevant Experience:

- Performed analysis and due diligence for numerous municipal and private acquisitions.
- He was a member of a team that reviewed, analyzed and selected financial and customer billing software for the company. The team accomplished this objective under budget and on schedule.
- Mr. Loy served on a team that re-engineered the meter testing and maintenance department. The result was a 50% reduction in costs and the department was eventually sold at a sizable profit.

1987-1989 Diversified Utility Consultants, Inc.: Sr. Accounting Analyst - Diversified Utility Consultants (DUC) is a consulting firm which represents consumers' interests in rate case proceedings. The firm's clients include municipalities and various state-supported consumer agencies. As a Sr. Accounting Analyst, Mr. Loy worked on seven electric rate cases, two gas rate cases and one water rate case. Additionally, he worked on various utility related assignments which included electric rate design for municipalities and the review and analysis of nuclear power plant decommissioning costs.

Prior to 1987 Mr. Loy spent summers in college roughnecking, both offshore and onshore, on oil and gas drilling rigs. His first job after college was in the oil & gas industry where he started in accounts receivable and specialized in collecting past due accounts. He was in the Joint Interest Auditing Department where he reviewed drilling costs and negotiated refunds for the company and its joint interest owners.

EDUCATION: Bachelor of Arts, Economics and French, Simmons College, Boston, Massachusetts, 1995

Brethren Colleges Abroad (BCA), Strasbourg, France
BCA Honors Program, Institut d'Etudes Politiques, Faculté des Lettres and Faculté de Théologie Protestante, 1994

EXPERIENCE:

Ms. Anderson has over six years of experience in the utility industry, with an emphasis on utility rate regulation and electric industry restructuring.

2001-Present GDS Associates, Inc.:

Analysis of electric and natural gas utility rate increase filings, rate unbundling proposals and restructuring policy. Provide assistance in the preparation of testimony and discovery in federal and state regulatory proceedings in areas including revenue requirements, cost allocation and rate design.

2000-2001 The Center for Business Intelligence, Woburn, Massachusetts:

Conference Producer for CBI's Energy Team. Conducted extensive market research to generate commercially viable topics and develop high quality, targeted conferences for the domestic energy industry. Interviewed, recruited, negotiated with and managed senior executive speakers. Led a production team for marketing, operations and sponsorship sales initiatives. Produced and managed conferences with revenues totaling over $500,000 on topics such as load profiling and forecasting, CRM, RTO market structure, fuel cells, desalination, electric asset valuation, electric distribution reliability, Clean Air Act compliance, pricing in wholesale and retail electric markets utility mergers and acquisitions and distributed generation.

1999-2000 La Capra Associates, Boston, Massachusetts:

Analyst. Developed forecasts of retail electric prices to help clients evaluate their position in the competitive marketplace. Provided analytical services to clients in multiple areas, including price forecasting, load profiling, stranded cost modeling and rate unbundling. Supported a team of consultants in areas such as regulatory policy, energy planning, market analysis, and pricing in the electric, natural gas, and water industries in the U.S. and abroad. Primary author of a comprehensive study of the history and status of electric industry restructuring in Massachusetts. Assisted in the preparation of expert testimony for presentation before Public Utility Commissions in several U.S. states in the areas listed above.

1998-1999 COM/Energy Services Company, Regulatory and Industry Affairs Division, Cambridge, Massachusetts:

Regulatory Analyst. Prepared rate cases, discovery responses, special contracts, rate reconciliation and review of purchased power agreements for filing with the MA DTE. Identified, analyzed, assessed, and followed emerging regulatory issues in the domestic electric and gas industries. Participated in the Massachusetts Gas Unbundling Collaborative. Assisted in the development and communication of policies and procedures consistent with and responsive to federal and state regulatory requirements. Provided project management and litigation support services for business and regulatory issues, including rate regulation, rate administration, and rate design. Assisted in maintaining and updating the company's Intranet site and oversaw the Y2K compliance activities of the company.

1995-1998 Massachusetts Department of Telecommunications and Energy, Electric Power Division, Boston, Massachusetts:

Economist. Reviewed and analyzed utility company filings pertaining to fuel and energy procurement, electric industry restructuring, energy conservation, and rate adjustments. Assisted in the development of a legislative proposal and regulations necessary to initiate competition in the electric utility industry in Massachusetts. Developed discovery and cross examined expert witnesses on testimony in public hearings before the Commission. Served as technical staff in settlement negotiations. Prepared and presented policy recommendations to the Commissioners of the Department. Represented the Commonwealth in the Massachusetts and Rhode Island Renewable Energy Collaborative groups, Massachusetts Energy Conservation Services Public Advisory Committee and DTE (Electric Industry Restructuring) Speakers Bureau.

1995 The Tax Equity Alliance for Massachusetts, Boston, Massachusetts:

Intern. Conducted an econometric analysis of the Earned Income Credit's (EIC) labor market effects and anti-poverty effectiveness. Assisted in the coordination of the 1995 EIC Campaign. Worked jointly with the Internal Revenue Service to maintain the EIC hotline and provide tax preparation assistance.

EDUCATION/CERTIFICATIONS:

AutoCAD 2000 – Basic; D.C. CADD Company
Y2K Readiness Certification, Lower Colorado River Authority
Microsoft Excel - Advanced; University of Texas MCC
Adobe PageMaker - Intermediate; University of Texas MCC
Microsoft Office 97 - Advanced; New Horizons
Building & Managing Internetwork; Wave Technologies
Downsizing & Client/Server Systems; Wave Technologies
LAN Fundamentals; Wave Technologies
Windows/LAN Conferences; Microsoft
Lotus 123 Training - Advanced; Dun & Bradstreet
C.Itoh Technical Certification, C.Itoh
dBase Programming - Advanced; Ashton-Tate
CNC Robotics Training, NASA
IBM Technical Certification, IBM
dBase Programming - Intermediate; Ashton-Tate
SALT Computer Aided Instruction Conferences; NASA
Cromenco Technical Certification
Apple Technical Certification, Apple
Computer Science; University of Houston

EXPERIENCE:

Mr. Kirkpatrick has had diversified experience in the micro computer field including installation and training for word processors, graphics, communications, spreadsheets, and databases. He exhibits expertise in the setup and repair of numerous DOS/Windows PC compatible systems, Palm Pilots, much of the Apple line of computers, and many other computer types. Computer languages that Mr. Kirkpatrick uses include Visual Basic, Lotus 123 and Excel macro scripts, dBase/xBase, Paradox PAL, Basic, Pascal, C, C++, some Fortran, Cobol, RPG II, Z80, and 6502 assembly. Mr. Kirkpatrick is also well versed in several Computer Aided Instruction authoring languages. Advanced database and spreadsheet skills are utilized in rate design and Cost-Of-Service modeling that Mr. Kirkpatrick is called on to develop, review, and customize. A description of his responsibilities follows:

1988-Present GDS Associates, Inc.:

Analyst, GDS Associates, Inc., Austin, Texas. Utilizing a broad technical training of both hardware and software, Mr. Kirkpatrick planned, installed and currently administers the Austin network and assists with other GDS corporate and client networks. Current project duties include the creation of gas and electric wholesale rate design models, Cost-Of-Service and Unbundled Cost-Of-Service models, aggregation of load data, water/wastewater inventory & cost estimation systems, extensive database system planning, implementation, and maintenance

as needed. Additional responsibilities include presentation layout and graphics design, software/hardware training and help desk duties responding to both corporate and client needs.

1986-1988 Rex Supply Corporation:

Salesman, Rex Supply Corporation, Houston, Texas. Duties included inside sales, outside sales and field delivery, and concurrent training in company supported Computerized Numerical Control (CNC) lathes.

1984-1986 Kirkpatrick Consulting:

Duties included on-call software and technical consulting to multiple small PC stores and contractual consulting to small businesses. Responsibilities included needs assessment, purchasing, installation, personnel training for hardware and software, custom database programming, and maintenance of wide varieties of micro computer systems.

1982-1984 Heliflight Systems, Inc.:

PC Specialist, Offshore Logistics Inc., Conroe, Texas. Responsibilities included installation, periodic maintenance, and repair of remote computer/training systems throughout Texas and Louisiana, and administration of an Apple II based Local Area Network at Heliflight headquarters. Primary duties included creation of Computer Aided Instruction (CAI) programs used by flight instructors for the initial training of foreign helicopter pilots, and used by maintenance department management and personnel to meet annual federal recurrent training requirements.

1978-1982 Retail Computer Stores:

Service Manager, Computer Technician, Salesman
Duties included inventory management, preparation and installation of new hardware and software, on-site installation and training, maintenance, system repair, sales and contract programming.

SPECIFIC PROJECT EXPERIANCE:

AquaSource Utility Inc., Texas

Development of a valuation of purchased assets database for 270 water/wastewater systems. Assisted in development of internet based facilities reporting system.

Citizens Utility Ratepayer Board

Provided gas Cost-Of-Service and rate design analysis.

City of Wahoo, Nebraska

Provided analysis of the Minnegasco acquisition.

Dayton Power and Light, Dayton Ohio

Creation of PC based data filtering program with operator definable parameters to handle anomalies and fully approximate corrupted records for data stemming from Time Of Use experiment for mainframe MIS department. This filtering system generates daily system status, record error reports, and historic error reports to enable Dayton Power and Light to investigate possible equipment problems.

Guadalupe Valley Electric Cooperative, Inc.

Aided in development and maintenance of Cost-Of-Service and rate design models. Helped to develop and maintain annual lease payment and net benefits analysis.

HEB Grocery Stores

Cost-Of-Service and rate design analysis in Central Power and Light, Entergy/Gulf States Utilities, Texas Utilities, and Texas-New Mexico Power rate cases. For Load Aggregation Pilot and Full Competition Power Supply Contracting projects, helped to identify potential suppliers, develop issue and pricing proposals, evaluate responses and provide analysis for negotiation of final contracts.

League Of Nebraska Municipalities

Provided gas Cost-Of-Service and rate design analysis.

Reliant Energy/Houston Lighting And Power

Aided in development and maintenance of cost allocation and unbundled Cost-Of-Service models. Provided analysis in fuel cases, assisted in water and sewer rate case, worked on FY2002 power cost budget analysis.

Rio Grande Electric Cooperative, Inc.

Analysis of issues in Central Power and Light, and CSW rate and transmission cases, assist in Transmission Cost-Of-Service filing package. Provided statistical analysis for Legislation Proposed in Rio's 76th Texas Legislature. Analyzed and graphed of West Region - Market Clearing Prices and produced aggregated load data files for West Texas Utilities and Lower Colorado River Authority.

Sharyland Utilities, L.P.,

Analyze preliminary transmission and distribution costs and assist in Certificate Of Convenience And Necessity filing. Co-developed Cost-Of-Service, Transmission Cost-Of-Service, and Unbundled Cost-Of-Service models and tariff sheets.

Tex-La Electric Cooperative of Texas, Inc. (Tex-La,) East Texas Electric Cooperative, Inc. (ETEC) ,and Northeast Texas Electric Coop (NTEC,)

Installation and maintenance of the multi-user document tracking database system, Case Information System by D-M Information Systems, Inc. Annual Southwestern Electric Power Company (SWEPCO) formula rate review and rate analysis.

ATTACHMENT
2

CONFLICT OF INTEREST DISCLAIMER

GDS Associates, Inc. (GDS) does not presently, nor has in the past, performed any professional services for Montana-Dakota Utilities Company (MDU). We are not aware of any conflicts of interest that may arise if GDS is chosen by the North Dakota Public Service Commission to investigate MDU's gas rate increase request in Case No. PU-399-02-183.

James W. Daniel
Vice President
GDS Associates, Inc.

Request for Proposal, Case Number PU-399-02-183

May 30, 2002

Stone & Webster Consultants™
A Shaw Group Compal

ORIGINAL

13 PU-399-02-183 Pages. 72

Response to Request for Proposal

by Stone & Webster Consultants a Shaw Group Comp

05/29/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Stone & Webster Consultants, Inc.

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Stone & Webster Consultants™
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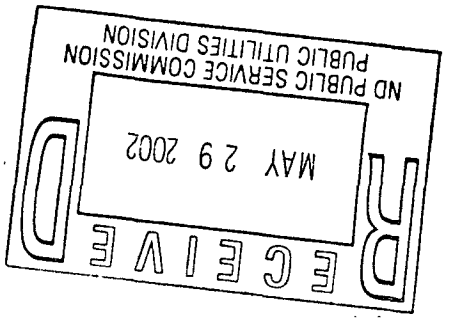
June 28, 2002



Mr. Mike Diller
Director of Accounting
North Dakota Public Service Commission
State Capital, 12th Floor
Bismarck, ND 58505-0480

Dear Mr. Diller:

Re: Proposal in Response to RFP Case No. PU-399-02-183 to Assist the Commission Staff in its Investigation of MDU's Gas Rate Increase Request

Stone & Webster Consultants, Inc. (Stone & Webster Consultants) is pleased to submit the enclosed technical proposal to provide consulting services to The North Dakota Public Service Commission (NDPSC) in connection with assisting the Commission Staff in its investigation of Montana-Dakota Utilities Co.'s (MDU's) gas rate increase request. Our proposal covers each of the five areas of the Commission's investigation. They are:

1. The appropriate level of investment;
2. The appropriate cost of capital;
3. The correct cost of service;
4. The appropriate rate design; and
5. Depreciation study.

We are very experienced in support of rate cases for commissions and for various types and sizes of utilities. Our experience covers the analysis of cost drivers, cost allocation, functionalization of costs, customer segmentation studies, cost of service and rate policies and their application, regulatory policy and regulatory strategy, rate design, performance based ratemaking issues and design and depreciation studies. In our appraisal studies performed for commissions, utilities and appellate tax boards, we regularly analyze the cost of money assumptions necessary for a litigated review of appropriate asset appraisals.

We recognize the importance of this effort to NDPSC and its responsibility as regulator, to assure that all stakeholders receive fair and equitable treatment. Stone & Webster

Consultants staff pledges to work closely as a team member with NDPSC staff to ensure that the objectives of this investigation are fully realized.

Stone & Webster Consultants is a premier international consulting firm in the electricity, gas, water and broader utility sectors. We have offices throughout the US, Canada and the UK. We are dedicated to providing strategic, economic, business, and technical services that offer value, insight, and expertise to clients worldwide. We are a knowledge-based firm with a reputation for delivering superior business solutions through an integrated set of products and services. Our client base is broad --- we serve companies in the electric, gas, and water businesses; investment and commercial banks; bilateral and multilateral institutions; and regulatory bodies and governments worldwide.

As a result of powerful global, regulatory, technological and economic forces at work throughout the energy and utility industries, our clients demand and receive customer-tailored business solutions that create real value. Stone & Webster Consultants offers its clients a comprehensive array of consulting services --- assisting the client in developing its vision and strategic plan, identifying and selecting economic and technical solutions which add value to their businesses, and providing on-site implementation services through the development and training of client employees.

Fundamental changes in the structure of the North American electric sector leading to a new competitive market are producing opportunities as assets are sold and companies merge and diversify. Stone & Webster Consultants is providing services to asset owners in the process of divesting and to asset buyers in their efforts to acquire, assets. Transaction support services include plant technical descriptions, competitive market evaluations and unit evaluations. In cases where companies are merging, Stone & Webster Consultants has provided independent appraisal services as well as assessments of and implementation of efficiency improvements. We have a staff of more than 250 consultants, with many more available when supplemented and complemented by our sister companies and business partners in Canada and the US, who are available to us as required.

Stone & Webster Consultants also offers the services of Power Technologies International (PTI), a leader in transmission and distribution consulting and software analysis and planning tools. PTI is a division of Stone & Webster Consultants.

Benefits of Choosing Stone & Webster Consultants

Stone & Webster Consultants has provided diverse services to clients worldwide from which this project can directly benefit – we are effective and efficient in our project approach, and bring professionals with broad knowledge of all aspects of the energy market. Stone & Webster Consultants has professionals with extensive supply knowledge, in both, electricity and gas markets. We bring a combination of business and technical knowledge to provide diverse analyses and strategies to our clients. We have advised executives, middle managers and technical staff – providing us a diverse set of experiences from which to draw. Highlighted below are a few of the excellent and targeted qualifications Stone & Webster Consultants will bring to this assignment:

☛ **We have performed more than 100 bundled and unbundled and marginal cost of service studies and rate design development in the US and Canada.**

Stone & Webster Consultants staff have completed segmentation analysis, cost analysis, and studies to assist utilities in their development and application of cost based rates. We are extremely knowledgeable in these areas and will contribute our extensive experience to the issues facing the NDPSC.

☛ **We have modeled and evaluated numerous domestic and international power generation, electric transmission, and natural gas pipeline facilities.**

Stone & Webster Consultants has reviewed existing and new electric generating facilities throughout the United States and in Canada. These reviews have been performed as a part of the following activities:

- utility asset sales –assisting both sellers and buyers,
- utility asset and equipment appraisals of value for use in asset sales or tax reviews;
- financings associated with asset purchases,
- financings associated with utility restructuring (transfer of assets to an unregulated subsidiary), and,
- financings of new merchant power facilities.

This experience affords us a global view of the impacts of utility financial issues, and costing and rate decisions.

☛ **We offer the services of a noted expert in depreciation studies for this effort.**

We have completed more than 126 depreciation studies since 1986, of which 47 have been for electric properties for commissions and utilities throughout our history. Our primary consultant for this effort has 39 years of experience as a consultant with Stone & Webster Consultants and four years experience as an independent consultant, including retention to perform Stone & Webster Consultants' depreciation studies. Our experts have provided testimony 48 times in 25 jurisdictions since 1986.

☛ **Our professional staff have completed more than twenty electric market pricing studies in the past year that assess the ability of a new generation unit to profit in the competitive market in the regions of interest.**

These studies involve an assessment of the bid based clearing price, potential capacity payments, and ancillary service revenues, while considering transmission load flows and potential constraints in the system.

- **We are committed to start and complete the assignment in a timely manner while ensuring stability of assigned staff.**

We have also conducted numerous consulting assignments throughout the country in support of regulators and regulatory strategy and issues for utilities and have a committed staff to support the requirements of this assignment.

- **NDPSC will have access to a broad range of experts.**

We have assembled a team of industry and functional experts with first-hand knowledge in utility economics, fully-allocated and marginal cost of service, rate design, valuation and financial studies, adjustment clause mechanisms and depreciation studies. We expect to work with you to ensure we have a full understanding of your concerns, and that the results of this study are meaningful.

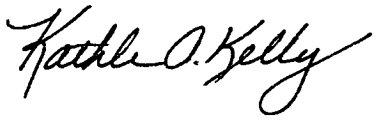
Compensation Proposal

Our estimate for services in each of the areas is set forth in the Fee Proposal section of this proposal. Our fee estimate (prior to preparation of testimony and presence at hearings) is based on a flat hourly rate of $185 per hour for all levels of consultants assigned to this project. This includes senior consultants through vice presidents at $185, with the exclusion of administrative support services that will be provided at $50 per hour as needed.

Closing

Stone & Webster Consultants sincerely appreciates this opportunity to present our proposal and qualifications. If selected, we will devote our best professional efforts to this assignment to assure a product of high quality and lasting value to the NDPSC. We trust you will find our proposals to be fully responsive to the requirements of your request-for-proposal. If you have any questions or need additional information please call me at 617-589-5215.

Sincerely,



Kathleen A. Kelly
Vice President and Practice Leader

CC: Mr. A. M. Ferrer

Proposal in Response to RFP Case No. PU-399-02-183
to Assist the Commission Staff in its Investigation
of MDU's Gas Rate Increase Request

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1. Experience

Stone & Webster Consultants is a leader in providing strategic, economic and technical review, study and engineering services for domestic and international Clients. We have considerable experience working in all segments of the utility industry having supported utility companies with asset divestiture, banking houses as lender's engineer including expert engineering analysis and financial evaluations and appraisal services to the industry. We provide a balance of technical and business services that include business and product strategies, regulatory and restructuring policy and strategy, utility economics, utility commission audits and rate case reviews, rate case unbundling and rate design studies, and collaborative facilitation services of a technical support nature. Stone & Webster Consultants provides the above multi disciplined full service capability for the power, gas, water and waste water industry in the United States and the world.

Stone & Webster Consultants, Inc. has extensive expertise in all aspects of energy planning, regulation, and restructuring issues. We have served the energy industry for over one hundred years and more recently played a crucial role assisting utilities and commissions with business strategy, deregulation issues, market dynamics, energy procurement, and energy saving strategies. Our broad and deep utility experience covers national and international energy issues.

With over 250 employees including economists, transaction advisors, financial analysts, institutional specialists, engineers and scientists, Stone & Webster Consultants is uniquely positioned to provide our clients the range of skills and experience required to meet the challenges of today's market.

Stone & Webster Consultants is a leader in providing strategic, economic and technical review, study and engineering services for domestic and international Clients. We have considerable experience working in all segments of the utility industry having supported utility companies with asset divestiture, banking houses as lender's engineer including expert engineering analysis and financial evaluations and appraisal services to the industry. We provide a balance of technical and business services that include business and product strategies, regulatory and restructuring policy and strategy, utility economics, utility commission audits and rate case reviews, rate case unbundling and rate design studies, and collaborative facilitation services of a technical support nature. Stone & Webster Consultants provides the above multi disciplined full service capability for the power, gas, water and waste water industry in the United States and the world.

Stone & Webster Consultants is part of The Shaw Group of Companies which includes our parent company Stone & Webster, Inc., an engineering and

construction company with a distinguished heritage of providing services to the energy and infrastructure sectors since 1889. Our geographic coverage includes work in 60 countries on more than 20,000 projects, and offices or representatives in over 27 countries.

With offices in the United States and around the world, Stone & Webster Consultants is staffed by specialists in private sector participation, regulation, utility economics, finance and institutional design.

Market and Regulatory Strategy Practice

Stone & Webster Consultants has provided Market and Regulatory Strategy Services for over 50 years to the electricity, water and natural gas industries. Stone & Webster Consultants formulates strategies and implementation tactics which inform management decision-making. Stone & Webster Consultants has been involved in the industry restructuring process from the outset and can aid electric and gas utilities, power retailers, power producers and aggregators in identifying opportunities and solutions as the new energy market emerges and evolves. Our staff is multi-disciplined and is equipped with the resources and experience necessary to assist every client in assessing the impact of changing markets on each client's operating environment and crafting strategies to create value for its shareholders.

Stone & Webster Consultants staff is skilled in strategic and market planning, utility finance and economics, utility regulation, energy market forecasting and resource planning, and customer information system development. We routinely design and utilize the most up-to date analysis tools in the energy industry. Tools such as cost of service and allocation models, market-pricing models, resource planning models, financial forecasting systems, and economic models, are frequently requested in responding to a client's request for service. We understand energy markets issues from the viewpoint of a variety of constituencies, including investor-owned utilities, cooperative distribution and generation and transmission utilities, municipal system operators, state and federal regulators, customers, and the newer market participants such as merchant plant operators and retail marketers or aggregators.

As a result of powerful global, regulatory, technological and economic forces at work throughout the energy and utility industries, our clients demand and receive customer-tailored business solutions that create real value. Stone & Webster Consultants offers clients a comprehensive array of consulting services --- from assisting the client in developing its vision and strategic plan, to identifying and selecting economic and technical solutions, right through implementation of the plan and follow-up.

1.1. RELATED EXPERIENCE HIGHLIGHTS

Several related projects are highlighted below that utilize the skill sets required for this type of assessment.

Alternative Rate Plans

Ms. Kelly reviewed testimony and exhibits filed in several jurisdictions relative to PBR in order to analyze the impacts and recommend the appropriate solution for one utility in the US. This required a review of gas, telecommunication, and electric PBR constructs to adequately reflect the intent of PBR as well as the revenue implications and implementation issues that might arise. Ms. Kelly testified to the positions in several regulatory forums.

Ms. Kelly and Mr. Boudreau have implemented a real-time pricing program, customer retention rates, interruptible rates, economic development rates, and other "new" rate designs. Implementation of such rates requires thoughtful anticipation of the trade-offs that may be encountered and simplicity in communication to customers.

Ms. Kelly implemented a demand-side management load curtailment program involving ten extremely large customers while at a Northeast utility. This required developing the incentive rate, persuading customers to participate, developing regular communication tools to hold their interest, managing monthly meetings of the customers to respond to questions and obtain suggestions for improvement, implementing a computer program to provide real time load and price information, and reporting the results to management and regulators. The program effectively reduced the utility's peak by nearly 30 MW at needed times.

Customer Retention Rates

Mr. Greneman completed the cost and rate studies that led to the development and implementation of customer retention rates at Southern Indiana Gas & Electric Company, Barbados Light and Power, Centra Gas, and China Light & Power, to name a few applications.

Mr. Greneman worked with Barbados Light and Power and Midland Electric Power Cooperative within the past year on the development of cogeneration rates.

Ms. Kelly and Mr. Boudreau initiated special contract rates designed to retain customers and attract retail customers with a choice of supplier in their positions at a Northeast Utility. In these same positions, they sought and received approval for manufacturer retention rates for large customers and economic development rates to attract large customers to the metropolitan area.

Rate Design and Cost of Service

The following is a description of recent cost of service and rate design projects completed by our consulting team.

Centra Gas of Manitoba, Inc.
Worked with utility staff to assess the policy implications and need for an inter-utility rate for gas service. Reviewed consistency of recommendation with corporate policies and regulatory policy. Developed inter-utility rate consistent with accepted rate designs and prepared documentation in anticipation of regulatory investigation.

Burlington Water Department
Prepared cost of service analysis and revised rate design for northeast water utility. Developed and implemented rate design alternatives designed to increase annual load and the utility's competitive position. Presented results to city managers.

Winnipeg Hydro
Reviewing cost of service study and providing recommendations for alternative functionalization and allocation methodologies based on client objectives.

China Light & Power Company, Ltd.
Performed a comprehensive review of this utility's cost of service and tariff system and made recommendations for tariff changes over the next five years in light of the current regulatory, economic and political environment in Hong Kong. A significant focus of the study pertained to structuring rates to encourage retention of industrial load that was closing operations, moving out of the service territory, or installing self-generation.

Midland Electric Power Cooperative (IA)
Provided testimony and exhibits in support of this cooperative's backup rates for cogeneration customers.

Regulation and Restructuring

New Jersey Board of Public Utilities - Electric Restructuring Audit
Engaged in a project on behalf of the New Jersey Public Utility Commission to audit, evaluate and critique the electric restructuring, stranded cost, and rate unbundling filings of one of the investor-owned electric company's in the state. Reviewed and audited the filings for accuracy, completeness, and compliance with New Jersey restructuring policy. Met with key utility staff to assess the extent of the efforts undertaken internally. Recommended modifications and additions to the filing where appropriate. Prepared and provided testimony on recommendations.

Colorado Public Utilities Commission
Forecasted wholesale prices in Colorado and the other sub-regions of the Western Systems Coordinating Council (WSCC) and utility stranded costs through 2017 under various policy scenarios, in support of legislative restructuring effort

New Jersey Board of Public Utilities – Market Assessment
Forecasted wholesale power prices in sub-regions of Pennsylvania-New Jersey-Maryland (PJM) interconnection, sub-regions of New York Power Pool (NYPP), and the other regions of the Eastern Interconnection, through 2015. Forecasted annual operating income and estimated market value and stranded costs of generation plants in New Jersey as part of the Board's review of restructuring changes.

Cost of Service and Rate Issues - Restructuring

Southwest Louisiana Electric Membership Corporation
Prepared an unbundled cost of service study and associated unbundled rates for an electric restructuring filing before the Louisiana Public Service Commission. Provided filing strategy advice and support for the case. Provided testimony and exhibits to unbundle costs and rates into power supply and distribution components. Developed a power adjustment clause mechanism, which the Commission recommended as a model for use by all cooperatives within Louisiana.

In a follow-on effort, prepared restructuring position white papers and regulatory support documents for submission before the Commission in its investigation of industry restructuring. Worked with the client to evaluate the business impact on the cooperative in anticipation of adoption of the various restructuring policies proposed in the state.

Montana-Dakota Utilities Co., (Montana)

Completed a marginal cost study and prepared expert testimony in support of a gas rate increase application.

Holyoke Gas and Electric Department
Completed an extensive cost of service effort for this East Coast municipal utility system with gas, electric, and steam operations. The project objective was a fully unbundled component cost of service study that properly separated the costs of providing service to each business line. Critiqued the utility's then current cost allocation procedures and provided recommendations for modifications that would better comply with the emerging competitive markets in that region. Conducted extensive cost and profitability analyses to determine the financial impacts of steam operations elimination upon the remaining gas and electric systems.

Consolidated Edison Company of New York
Developed menu-driven fully unbundled cost of service studies for electric, gas and steam operations for use in the company's restructuring filings before the New York Public Service Commission.

Southern Indiana Gas and Electric Company
Provided ongoing regulatory support including fully unbundled electric and gas cost of service studies, development of fair value rate base, rate design and preparation of testimony and exhibits. Unbundled cost of service studies were heavily relied on in developing new projects and successfully attracting new business to the service territory, including an automobile assembly plant.

Northern Indiana Public Service Company
Developed fully unbundled cost of service study for electric operations in preparation for restructuring and support of current rates.

Commonwealth Edison Company
Developed fully unbundled electric cost of service studies and testimony for rate cases, including a functional unbundling study in support of the company's Distribution Services Tariff proceeding pertaining to restructuring in Illinois.

Edison Sault Electric Company (MI)
Provided ongoing regulatory support including fully unbundled cost of service and rate design studies, supported by preparation of testimony and exhibits.

Barbados Light and Power Company, Ltd.
Developed unbundled cost of service study and provided recommendations for changes to rate structure with the objective of retaining industrial customers considering self-generation.

Western Municipal Utility
Prepared first unbundled cost of service for the client, developed recommendations for changes in accounting and reporting to facilitate updating study. Assessed the changes necessary to rate structure relative to the unbundling of costs. Advised client on California restructuring issues and implications for their financial viability. Recommended the treatment of potential stranded asset costs and developed an implementation plan for recovery.

Resource Planning And Acquisition

Santee Cooper - Generation Resource Planning Study
Performed a comprehensive generation resource planning study for Santee Cooper in 1998. This study included a comprehensive assessment of all potential supply-side options including self- and joint-ownership, cogeneration, and all types of purchased power and sales. The study consisted of six major tasks: (1) Project initiation, (2) Resource bid solicitation, (3) Supply-side analysis, (4) Integration and evaluation, (5) Sensitivity and risk analysis, and (6) Report and presentation. A key part of the study was to prepare a letter and specifications to solicit bids from potential power suppliers, and to evaluate/rank the bids received in comparison to other supply-side options. To perform the "integration" analysis of the power supply bids and supply-side options we used the EGEAS optimization model to determine the least-cost generation resource plan.

Kissimmee Utility Authority (KUA)
Assisted KUA with development of an integrated resource plan for the years 1996 through 2015. Specifically, assisted KUA with the development of a system load forecast, evaluation of DSM and supply-side planning alternatives, financial analysis of the resulting plans, and evaluation of the risk associated with the various scenarios and futures that were considered to be realistically possible.

City of Tallahassee
Performed the initial integrated resource plan for the City of Tallahassee and a subsequent update that determined the timing and type of the most cost-effective resource to add to the system. Based upon the results of the IRP the

City of Tallahassee issued an RFP solicitation for new capacity. Assisted the City in the development of the RFP and also performed the bid evaluation including a detailed sensitivity and risk assessment. The City of Tallahassee accepted our recommendation for the best bid. Appeared before the Tallahassee City Council in support of the recommended project and the City Council approved the recommendation.

Lansing Board of Water & Light (LBW&L)
Evaluated electric and steam supply-side planning alternatives to complete an integrated resource plan. Created a "base case" which modeled existing generation resources, then evaluated and modeled generic power supply options as well as existing repowering options. Finally, created a checklist of unit data requirements for all electric and steam options to be evaluated in the final IRP.

Barbados Light & Power Company
Performed the generation and transmission expansion study for the island of Barbados. As part of that study performed a retirement study on the existing generation in addition to developing a list of candidate resources to be used for future resource additions. The generation expansion plan analysis took into consideration site locations and the cost of site impacts on transmission expansion. Determined the reliability criteria to be used in the study as a function of loss of load probability. The impact of renewable resources such as wind energy and municipal solid waste were evaluated for economic feasibility and their impact on reliability.

Public Service Company of New Mexico (PNM)
Performed all aspects of the RFP process associated with the solicitation of a peaking capacity resource. Provided oversight to the design of the RFP and developed the structure by which bids were evaluated. Facilitated the development of the non-price criteria. Performed the price evaluation of all bids and incorporated the non-price evaluations into a combined ranking. PNM accepted our recommendation for the short-listing of bids. Also performed the price evaluation of the short-list bids including a sensitivity and risk assessment. Testimony for this study was provided.

Union Bank of California, BZW Division of Barkleys
Used the Pennsylvania-Jersey-Maryland EGEAS database to determine the market value of the Warrior Run power plant. The model assumed the unit was running within the PJM system to determine the capacity and energy savings that would be obtained if the Warrior Run plant was included in the system.

Wisconsin Public Service (WPS)
Assisted WPS in a resource plan filing. Demand-side and supply-side alternatives were evaluated. Completed several EGEAS computer runs to be

used in their integrated resource plan. Risk and financial analyses were also completed as a part of this study effort.

Southern Indiana Gas & Electric Company (SIGECO)
We periodically carry out an investigation and analysis of the economic, social, and technological factors that effect energy sales over a 20-year forecast period. Our work covers a wide range of socioeconomic factors, among which are national, state, and local trends; population; migration; birth rates; housing and energy economics for the residential, commercial and industrial sectors. The basic approach of this study is end-use analysis for the residential class and a combination of econometrics and end-use techniques for the small commercial and industrial classes. An examination of appliance saturation coupled with appliance efficiencies and the impact of competitive fuels (particularly natural gas) is included in addition to an evaluation of the social and economic trends of the area.

Stone & Webster Consultants has performed various IRP studies for SIGECO's electric and gas systems. The studies included a comprehensive analysis of all supply-side and demand-side options and the development of an integrated resource plan. Also provided support with pre-filed testimony and served as expert witnesses in regulatory hearings before the Indiana Utility Regulatory Commission.

Oklahoma Gas & Electric (OG&E)
Integrated Resource Plan - Assisted OG&E Electric Services with development of an integrated resource plan. Assisted OG&E with the evaluation of DSM and supply-side planning alternatives, environmental strategies, financial analysis of plans, and the risk associated with the various scenarios and futures that were considered to be realistically possible.

Market Analysis

The experience outlined below in many cases was completed for clients that wish to remain confidential. The wholesale price studies were developed and cover all the NERC regions of the US considering interconnections, market rules, plant ownership and operation, expected introduction of customer choice, fuel price forecasts, and merchant plant operation characteristics. These studies provide dispatch information, operating characteristics, capacity market prices, energy market clearing prices and the resulting plant revenue expectations. A summary of the numerous studies undertaken is provided below.

Type of Study	# of plants	Regions Modeled
New Unit(s)	5 thermal	ECAR, FRCC, PJM, MAIN, MAPP, NPCC, SERC, SPP
Repowering	1-thermal	SERC
Asset Valuation	1-hydro	NPCC
Portfolio Valuation	4-thermal	PJM, NPCC
Asset Valuation	10-thermal	ECAR, FRCC, PJM, MAIN, MAPP, NPCC,SERC, SPP
New Unit(s)	1-thermal	Mexico
New Unit(s)	1-thermal	Poland
Asset Valuation	19-thermal	Poland
Asset Valuation	>30 hydro and thermal	WSCC
Repowering	1-renewable	WSCC
New Unit(s)	2-thermal	ECAR, MAIN, MAPP, SERC, SPP
Many Market Price Only Studies	Various units and combinations of units	Various regions

Aggregation and Resource Acquisition

Rhode Island League of Cities and Towns
Worked with a Municipal agency to assess and incorporate the electricity purchasing requirements of its members into a designed RFP, reviewed supplier bids, negotiated a five-year contract, and evaluated actual savings for members. Represented members and organization in regulatory investigation into restructuring implementation planning. Providing ongoing advice relative to contract issues and regulatory investigations.

Rhode Island Public Transit Authority
Developed and issued RFP to procure gas service for existing and under construction structures. Reviewed bids and market to recommend successful negotiation partner. Contract negotiations underway with selected bidder(s).

University of Michigan
Developed and issued an RFP for electric and gas energy procurement for large campus. Worked with the client to assess needs, reviewed bids and assisted in the contract development.

Industry Restructuring Issues

Stone & Webster Consultants has been very active in the market development process in the majority of restructured states within the US as well as in privatization activities internationally. Stone & Webster Consultants has actively participated in:

- Legislative language development;
- Policy consideration and recommendations (including PBR);
- Negotiation of legislative language and utility settlements;
- Developing unbundled cost and rate studies,
- Reviewing customer retention policies and alternative rate structures (RTP, PBR),
- Developing competitive markets for electric generation;
- Assisting commissions with review of plans and assessing impacts;
- Establishing the rules of competition for suppliers and distributors;
- Evaluating stranded cost calculation and impacts on the market; and
- Developing market interaction requirements and settlement.

New Jersey Board of Public Utilities - Electric Restructuring Audit
Engaged in a project on behalf of the New Jersey Public Utility Commission to audit, evaluate and critique the electric restructuring, stranded cost, and rate unbundling filings of one of the investor-owned electric company's in the state. Reviewed and audited the filings for accuracy, completeness, and compliance with New Jersey restructuring policy. Met with key utility staff to assess the extent of the efforts undertaken internally. Recommended modifications and additions to the filing where appropriate. Prepared and provided testimony on recommendations.

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plants in New Jersey as part of the Board's review of restructuring changes.

Indiana Public Service Commission
Provided a fair value study or valuation of rate base for SIGICO.

California Public Service Commission
Valuation of the transmission and distribution system for sale of PG&E.

Ontario Energy Board
Developing a Performance Based Ratemaking standard for electric utilities in the province.

Expert Testimony

Most of our staff has provided testimony before regulatory commission on various subjects.

Mr. Greneman has provided rate case testimony to the following:

Delaware Public Service Commission
Federal Energy Regulatory Commission
Indiana Public Service Commission
Iowa Utilities Board
Kentucky Public Service Commission
Louisiana Public Service Commission
Michigan Public Service Commission
Montana Department of Public Utilities

Ms. Kelly has presented testimony in many cases before the Massachusetts Department of Telecommunications and Energy (MA DTE) and the Energy Facilities Siting Council (EFSC).

- Investigation into the restructuring plans of Orange & Rockland before the New Jersey Board of Public Utilities (1998).

Mr. Strand has provided testimony on depreciation studies 48 times since 1986 in 25 jurisdictions.

Mr. Green has provided valuation testimony in litigated valuation cases involving electric transmission and distribution systems, gas distribution systems, water and wastewater systems and power generating facilities. He has prepared dozens of appraisals of all types of utility property over the past two decades with most of them prepared in anticipation of litigation (i.e. either condemnation or property tax disputes). In all cases, the proper cost of capital or discount rate is a fundamental element of the appraisal process and must withstand challenge in a litigated context.

2. Technical Approach

2.1.1. The appropriate level of investment in North Dakota

In keeping with the NDPSC's limited focus on the appropriate level of investment, Stone & Webster Consultants will rely on a review of the last MDU rate case along with historical comparisons. Annual reports filed with the Commission will provide a principle source of all rate base components. Stone & Webster Consultants assumes that the scope of the NDPSC investigation in this RFP does not include a review of the propriety of any rate base allocations between the North Dakota jurisdictional customers and other jurisdictions and/or affiliates. If such review is indeed desired, Stone & Webster Consultants is extremely qualified to perform this work. However, the fee estimate does not include this effort.

2.1.2. The appropriate cost of capital

Stone & Webster Consultants will perform an extensive review of MDU's cost of capital filing including a critique of their fundamental assumptions and their selection of comparable companies, capital structure, data sources, model application and final recommendation. This analysis will not include our own independent cost of capital study using our preferred data sources and methodologies, but will instead include our recommendation resulting from our review and/or correction of MDU's filing.

2.1.3. The appropriate cost of service

Stone & Webster Consultants will perform an extensive review of MDU's operating and maintenance expenses including actual test-year expenses as well as pro forma, annualization and normalization adjustments. The review will be done on an account by account basis and focus on the appropriate level of the expenses and assessed against past expenses, industry norms, company issues and circumstances as well as Commission mandates. A significant effort in this task will focus on the level of gas cost, which is dependent on weather-normalized sales. We will perform a thorough review of MDU's weather normalization procedure.

Stone & Webster Consultants assumes that the scope of the NDPSC investigation in this RFP does not include a review of the propriety of rate base allocations between the North Dakota jurisdictional customers and other jurisdictions and/or affiliates. If such review is indeed desired, Stone & Webster Consultants is extremely qualified to perform this work. However, the fee estimate does not include this effort.

2.1.4. The appropriate rate design

Stone & Webster will perform a thorough review of MDU's proposed rate design, including level of monthly customer charge, usage block structure and rate provisions. In performing this task, we will rely on unbundled cost components as detailed in the company's cost of service study, as available, customer class composition, class usage characteristics, competitive and other relevant concerns. As indicated in the RFP, in the event the Commission does not accept the basic service charge increase, MDU is arguing for the inclusion of a weather normalization adjustment. To this end, Stone & Webster Consultants will assess the appropriateness of MDU's proposed $11.70 customer charge against the customer-related cost to serve and the components included, e.g., minimum system, services, meters, billing, collecting, etc. We will also perform a intensive review of MDU's weather normalization adjustment mechanism. As appropriate, Stone & Webster Consultants will make alternate recommendations to the NDPSC for ways to stabilize revenues due to year-to-year weather variations.

2.1.5. Depreciation Study at the Request of Staff

If requested, SWC will conduct a depreciation study of the Company's depreciable properties using established proven techniques. We propose to conduct the study using the broad group (or average life) procedure, remaining life technique and straight line method. Determinations of average service lives and estimated mortality patterns (Iowa curves) will be based where possible on the simulated plant balance methodology using the Company's historic database. The effect of estimated gross salvage and cost of retirement/removal will be included in the depreciation rates, and will also be based to the extent possible on the Company's specific experience.

As an integral input to the judgment required in conducting a depreciation study, it may be very helpful in talking with several staff members regarding pending or possible changes in specifications, operating policies or other factors which have a bearing on plant service lives, extraordinary retirements, and the like. This might include inspections of major and representative assets.

A depreciation study follows a certain general path, with inevitable variations. Some of the activities may be carried on together; others may be done in different sequencing. In general, the procedure is as follows:

- The data required for the study is obtained and edited. The data comprises, for each
- primary plant account to be reviewed, annual dollar additions and retirements for the history of the account. (Should this history be extremely long for certain accounts, 40 or so years will suffice). Some accounts will have comparatively short

histories. The actual need for a certain span of years depends on the nature of the property. Also required are dollar amounts of annual gross salvage and/or retirement cost (negative salvage) if any, for each separate account but only for the most recent 10-12 years. The final need is for the current plant balance and reserve for depreciation for each account. Only the most recent year is required for this data.

- Editing each account means it is checked for being in balance. All additions ever made less all retirements ever made should equal the current balance. If not, some adjustment is needed. Editing also attempts to place accounting adjustments of account-to-account transfers or year-to-year adjustments in the pertinent year instead of the year in which the accounting change was made.
- One of the outputs of the editing process are the results of first in-first out turnover testing, an old and still useful tool for service life study.
- The accounts with adequate data, in terms of total years of length and number of years with retirements, are then tested by means of the simulated plant balance technique. This means that computer simulations of a span of years' worth of plant balances is compared with the actual historical balances. The account's actual record of annual additions is analyzed under a wide variety of service lives and mortality dispersions (Iowa curves) to create a number of simulated balances by calculating and summing the surviving plant from past annual additions. Generally one life and curve combination will produce balances close enough to the actual balances to permit the conclusion that this fairly represents the performance of the account historically.
- The move to the next step involves considerable judgment and experience. It must be decided whether each account can be expected to continue in its present apparent life pattern, or whether there are reasons for a change in the future. Company managers may have knowledge of changed plans, conditions or regulations which could affect service lives, remaining lives or salvage factors. There may be other reasons for change, as well.
- After lives, curves and salvage factors are selected, the estimated future service life of the dollars surviving from each annual addition is calculated, in accord with the life and Iowa curve factors, and the dollar weighted average remaining life of the whole account determined. Typically in a simulated plant balance study an account's vintage survivors are calculated in accordance with the dictates of the chosen Iowa curve. This is

also usually necessary as most utilities can not provide plant balances as a summation of vintage year survivors.

- The depreciation rate appropriate for each account is produced by means of a spread sheet as follows: the current plant balance is increased by some percentage representing the amount needed for future retirement or removal cost, or decreased by some percentage expected as gross salvage upon retirement. This amount is then reduced by the amount of the current reserve for depreciation to obtain the undepreciated amount in the account. That result is then divided by the years of remaining life to produce an annual amount of depreciation accrual to adequately provide for the retirement of the dollars in the plant balance over their future expected life. The accrual amount, divided by the plant balance, produces a depreciation rate (percentage) that may be used over a reasonable period into the future to depreciate past survivors, as well as future additions, if they can be expected to have similar characteristics.
- The next step is to present this summary spreadsheet to NDPSC as a preliminary finding and engage in questions, answers, and if warranted, revisions should some information have been overlooked or misinterpreted.
- The final report describes the methodology involved and any information necessary to explain unique situations or deviations from routine test results and the like; the summary spread sheets presenting the depreciation rates, described earlier; and the detailed worksheets computing the remaining life of each account.

2.1.6. Methodology and Process

In association with the above tasks, Stone & Webster Consultants will:

1. Prepare and conduct discovery as necessary;
2. Provide monthly progress reports of discovery, conclusions and recommendations;
3. Prepare and file written and oral testimony;
4. Assist staff in preparing cross-examination of the witnesses of other parties tothe proceeding; and
5. Assist staff in the preparation of proposed findings of fact.

3. Schedule

Stone & Webster Consultants is prepared to begin work within one week of your authorization to proceed and will dedicate the resources needed to meet the August 30th completion date for the investigation and written testimony.

4. Personnel

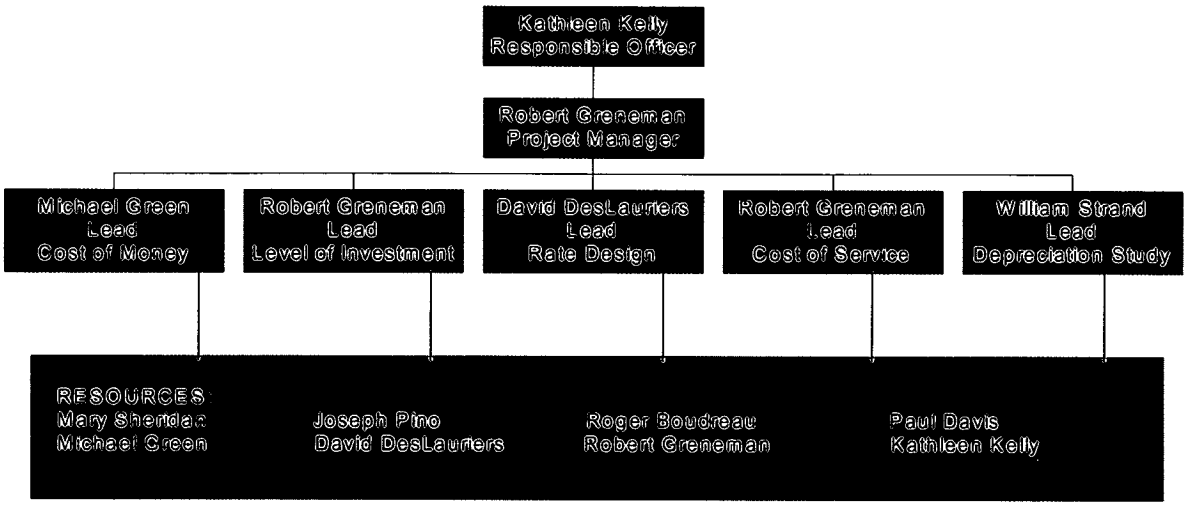
Stone & Webster Consultants will establish one overall project manager reporting to Kathleen Kelly, the corporate responsible officer for this project. This project manager will communicate regularly with NDPSC staff, establish key deadlines, assign appropriate personnel for the effort, and manage the day to day activities as work progresses. We have identified key contributors that will participate in this work effort to provide the technical and management requirements. A summary of our key participants is provided in this section. Resumes for the key team members are provided in Appendix 1.

Ms. Kathleen Kelly is actively involved in the restructuring process in several states and has over 20 years of extensive rate policy, business strategy and planning, consensus building, and regulatory policy experience. Ms. Kelly, located in our Boston office, has presented expert testimony on many subject areas and has recently directed engagements for municipal and cooperative utilities involving industry change and competitive positioning. Ms. Kelly has extensive experience in utility business management, policy and regulatory issues, competitive development, rate issues, load research, forecasting, demand-side management, resource planning, asset valuation, and group facilitation. She has worked with the New Jersey Board of Public Utilities and is currently working with the Ontario Energy Board and Centra Gas BC on application of restructuring and PBR policies. Ms. Kelly has prepared for many rate cases in numerous jurisdictions and is knowledgeable in restructured utility issues.

Ms. Kelly will be assisted by Mr. Robert Greneman, Mr. David DesLauriers, Mr. William Strand, Mr. Michael Green, Mr. Roger Boudreau, Ms. Lisa Vedder, Mr. Paul Davis, Mr. Joseph Pino and Ms. Sheridan. Resumes for each contributor are included in Appendix 1.

Mr. Greneman, Associate Director and Project Manager for this effort, has more than thirty years of experience in electric, gas and water utility cost of service, rate design and analysis. He developed our own SCOST model, which we utilize and license to our clients for cost of service use. He has testified before many commissions and has advised more than 100 utilities across the US, Canada and worldwide on cost of service issues and rate design. He has also prepared a marginal cost study for MDU's Montana division and will contribute his strong technical knowledge in the level of investment, cost of service and rate design areas of the effort. As project manager, he will ensure the technical recommendations are effective and that the personnel are available and efficiently completing the assignments.

Project Organization



Mr. DesLauriers has more than fifteen years of experience with electric, water and gas utilities and commissions with respect to rate case development and review. He brings a balanced view of the rate case, having reviewed utility filings for commissions in the past. He will contribute his knowledge of rate design, cost of service and utility economics to this project.

Ms. Lisa M. Vedder has extensive senior-level experience in the energy industry with emphasis on electric and gas industry restructuring. Her areas of expertise include regulatory policy, rate-making, technical and financial evaluations of power generation technologies, including alternative fuels, energy contracts, and financing of complex sale/leasebacks & swaps.

Mr. Strand has 39 years of experience as a consultant with Stone & Webster. 4 years experience as an independent consultant, including retention to perform Stone & Webster's depreciation studies. He has completed 126 depreciation studies completed since 1986, of which 47 have been for electric properties. He has provided 48 testimonies in 25 jurisdictions since 1986. In addition to the 126 completed studies mentioned above, a considerable number of other small assignments, such as annual updates, have been done.

Mr. Michael Green has nearly twenty years of experience in the valuation of utility property with most of that experience derived from actual or potential litigated valuation cases. His training in finance, working knowledge of the regulated industries and unique appraisal background gives him a "real world" perspective on market required rates of return for utilities. He is well-versed in

the theoretical underpinnings and practical applications of the standard cost of capital models and their various iterations (e.g. multi-staged DCF models, multi-factor build-up models, levered and unlevered beta methodologies, etc.)

Mr. Boudreau has more than thirty years of experience in utility management in the areas of distribution planning, load research and cost of service and rate design. As Manager of Load Research at a northeastern US utility, he implemented a load research effort and managed the accumulation, analysis and use of the data for more than twenty years. He also worked with cost of service studies and rate case development utilizing the load research and cost information he developed.

Mr. Joseph Pino has recently joined Stone & Webster Consultants and brings more than twenty years of experience in data applications, analysis and cost of service and rate design. He has extensive customer information and billing system background and has developed PBR for the utility he recently left. He will work with others in the review process.

Mr. Paul Davis contributes more than thirty years of planning and rate experience to this project. He has modeled all of the NERC regions to establish resource plans and market pricing for deregulated markets.

Ms. Mary Sheridan specializes in the technical and financial review of power generation projects. She has over twenty years of expertise in pro forma economic reviews, contract reviews, performance evaluations, feasibility studies, due diligence reviews, and bid evaluations. Ms Sheridan also has extensive regulatory experience at the state and federal level.

5. Fee Proposal and Rates

Based on your RFP, Stone & Webster Consultants estimates a fixed price for each task as set forth below. We welcome the opportunity to meet with you to expand on our qualifications and discuss the scope of the tasks in more detail. At that time, we will be better able to prepare a final fixed price estimate based on a more complete understanding of the work.

TASK	DESCRIPTION	HOURS	COST
Task 1	Level of Investment	80	$15,000
Task 2	Cost of Capital	108	$20,000
Task 3	Cost of Service	162	$30,000
Task 4	Rate Design	108	$20,000
Subtotal (excluding testimony)		460	$85,000
Preparation and presentation of testimony		90	$22,000
Total		550	$110,000
Task 5	Depreciation Study (optional)	270	$50,000

The above fixed price estimates are based on a billing rate of $185 per hour for all level of consultants from senior consultant to vice president, for all efforts excluding testimony. For testimony preparation and actual testimony we offer our standard rates on average $245 per hour for executive consultants or associate directors. We will include the first 80 hours as part of the fixed cost estimate for testimony at $245 per hour; all additional hours will be agreed to by the NDPSC before they are undertaken.

Our actual invoices to the NDPSC will be based on the hours that each consultant worked on the project; as such, the final billing may be less than the final fixed price estimate. We will not exceed the final fixed price estimate without your express authorization, based specifically on reasons such as expanded scope, our unforeseen involvement in specific areas of review, or protracted hearings.

The fixed price estimate excludes travel to your office. All travel costs will be billed at our cost, and are typically 15% of the labor cost for an effort. Anticipated expenses for travel are $10,750, and are only invoiced to you as incurred.

We have also provided our standard contract for your information. We will work with you on mutually agreeable terms under which to conduct this assignment.

6. NDPSC Responsibilities

NDPSC staff is responsible for the following:

- Provision of data, assumptions, constraints and filings in electronic format, if available.
- Timely review of communications provided by Stone & Webster Consultants such that the schedule can be met;
- Access to appropriate information from current studies to facilitate efficiency and eliminate duplication of efforts; and
- Provision of regulatory precedent and orders of importance to the issues under study.

7. References

Bob Banburak
Winnipeg Hydro
234 James Avenue
Winnipeg, Manitoba R3E 3G2
204-986-2304

Geoff Higgins
Manager of Regulatory Affairs
Centra Gas British Columbia, Inc.
1675 Douglas Street
Victoria, B.C., V8W3V3
250-480-4454

Brian Kading
Executive Director
Iowa Association of Electric Cooperatives
Des Moines Iowa
515-727-8941

Mr. Edward Washington II
Bureau Chief-Public Utilities
Illinois Attorney General's Office
100 W. Randolph Street, Chicago, IL 60601

James Rekulak
State of New Jersey
Board of Public Utilities
Bureau of Management Audits
Division of Audits
Two Gateway Center
Newark, NJ 07102
973-648-4516

8. Appendix 1 Resumes of Key Personnel

KATHLEEN A. KELLY

Vice President

An experienced manager with twenty-five years of leadership, supervisory and project management experience. Management consultant with extensive strategic utility experience including retail industry restructuring issues, developing a competitive industry framework, business analysis, market strategy, functional unbundling, market analysis, stranded costs, re-regulation, pricing, and business infrastructure implementation planning and education. Facilitates and advises senior managers on strategic issues and strategy development and implementation. Experienced in corporate planning, forecasting, management, valuation, market research, rate design and cost unbundling, utility management, and Demand-Side Management (DSM) planning, implementation and evaluation. Provides expert testimony on retail restructuring, rate design, forecasting and DSM.

PROFESSIONAL EXPERIENCE

1997 - Present **Stone & Webster Consultants, Inc. Boston, MA**

Vice President

Highlights of Recent Consulting Engagements:

Completed efforts with several clients to *value a potential acquisition* of utility assets including auctions of assets.

- Provided decision tools including pro forma income statements including assessment of potential risks. Directed the efforts of a team of experts reviewing data room materials to assess the revenue and cost impacts of the available information. Prepared market assessment for generation opportunities in various markets. Assets analyzed include generation, transmission, distribution and competitive businesses.
- Advised a client in the assessment of opportunities, risks and financial alternatives in the consideration of an acquisition.
- Reviewed the business plans, financial proformas, and assessed the potential business value for more than 15 power facilities worldwide. This effort included an assessment of upside value potential.

Completed a three-phase project working with the *Iowa Association of Electric Cooperatives*. Phase one involved the facilitation of a restructuring task force comprised of member cooperatives working together to strategize and formulate their joint restructuring position. Developed written educational material on key restructuring issues and outlined alternative positions on those issues, identified potential cooperative business impacts, and facilitated

discussion and documentation. Phase two relied required both facilitation and technical knowledge and focused on negotiation strategy and implementation of that strategy, resulting in a cooperative leadership role in state restructuring legislation development. Phase three developed and implemented an education series for cooperative managers, directors and employees to prepare for industry restructuring.

Worked with *Centra Gas Manitoba* to develop strategic rate options for customers. Required an assessment of current policies in the United States and Canada for both gas and electric utilities. Worked with the client to develop policy recommendations for management review.

Directing two audits of two major eastern utilities' distribution outage situations to determine the cause and recommend improvements.

Worked with the City of Fayetteville Public Works Commission and the Town Manager to assess the planning for competition by identifying business lines and evaluating appropriate lines of business in a competitive environment. Developed a financial model of the independent business lines from a fully bundled business for use in decision analysis. Presented findings to the governing board.

Arbitrated the development of appropriate pricing for a new unit contract for an island based water and power authority. Presented and defended conclusions before the board. Worked with two clients to establish joint assumptions and methodologies.

Working with a client to assess alternative resource procurement strategies for an aggregation with more than 500MW of electricity consumption.

Directed the procurement effort for gas by the *Rhode Island Public Transit Authority.*

For the *New Jersey Board of Public Utilities* (NJBPU) reviewed Rockland Electric's utility restructuring plan for completeness and compliance with NJBPU guidelines for New Jersey's restructured electric industry. Recommended necessary changes in the proposal, interviewed utility management to gauge implementation activities, and advised and testified on behalf of BPU staff on restructuring implementation planning.

Worked with a collaboration of *Massachusetts utilities* to foster discussion and development of new terms and conditions of service between competitive suppliers and distribution utilities and updating customer terms and conditions of service to reflect standard offer service, default service and changes in customer relationships. Developed meeting strategy, facilitated discussion and closure on issues, provided a central clearinghouse for comments, and

supported discussions with technical knowledge of current and new market requirements.

Developing unbundled costs, rates and rate strategy for a *Southern electric cooperative* and prepared positions and regulatory support documents for restructuring the electric industry in that state. Worked with the client to examine the impact of various policies identified by the state regulatory commission and assessed the potential impacts. Identified alternatives restructuring proposals to provide to the regulatory commission.

Completed a successful energy procurement process for the *Rhode Island League of Cities and Towns*. The effort required an assessment of market opportunities that would provide the greatest savings opportunities to participants. Stone & Webster Consultants developed supporting information, facilitated the definition of needs of the more than thirty cities and towns, and worked with commission staff as needed to obtain information or to influence their decision making process relative to standard offer tariffs. Developed and issued both a short and a long term RFP, evaluated proposals, and negotiated the final contract for services. Presented recommendations to the client's board and to their members as needed.

Worked with *several municipal utilities and joint action power agencies* in separate projects to assess the impact of competition on their operations, developed strategies for the businesses to grow, and facilitated the development of implementation plans for successful growth. Responsibilities included the unbundling of costs and rates, identification of business issues, development of potential strategies, assessment of those strategies on the municipal utility as well as the town government, and presentations at public meetings. Specific restructuring issues include the development and assessment of transition cost recovery methodologies and standard offer or basic generation services.

Facilitated *strategic planning sessions* for several cooperative and municipal utilities to establish strategies for a competitive market framework. Advised the manager and senior management team of a municipal utility on strategic issues and planning for competition, providing a decision analysis tool and developing and evaluating alternative strategies. Worked with the team in assessing the opportunities and risks associated with each strategy.

1977 - 1997 **Boston Edison Company**
Manager of Industry Restructuring

Held various positions within the corporation managing groups of professionals in marketing, analysis, rate design, regulatory issues, business strategy, and DSM planning and evaluation. A summary of key activities is provided below by topic area.

Industry Restructuring

Author of Boston Edison's electric industry restructuring plan, evaluating strategic financial, operational and customer impacts of the proposed plan and building consensus both within and outside the corporation. Negotiated solutions with regulators and third parties resulting in settlement of major issues. Identified the structure and resources necessary to meet the demands of the new competitive energy market. Developed strategies for business infrastructure implementation. Coordinated regulatory strategy and witness preparation. Expert witness on rate design, implementation issues and customer education requirements. Company representative on industry working groups investigating and negotiating statewide restructuring issues. Spokesperson with area trade associations, businesses and customers on industry restructuring.

Market & Competitive Analysis

Developed a competitive marketing plan utilizing market research results in preparation for a transition to a competitive environment. Initiated competitive positioning analysis at a northeast utility by working with senior management to define strategic information and analysis requirements. Completed a first time assessment of competitive customer value of electricity and the utility's competitive position, while completing a competitive positioning analysis of bundled and unbundled electric pricing. Directed the development of in-depth competitor assessments covering market share, pricing strategy, and restructuring positioning and new market strategies.

Utility Regulation

Extensive regulation and regulatory interaction experience. Developed resource plan filings, DSM budgets, DSM evaluation and reconciliation for cost recovery purposes, rate filings and restructuring filings. Testified before regulatory commissions supporting sales forecasting and resource planning, DSM planning, rate structures and restructuring proposals.

Rates and Pricing

Directed the development of cost allocation methods, retail and wholesale tariffs and filing requirements for rate cases. Successfully implemented the use of creative utility pricing tactics. Positioned a utility as the first in the region capable of regional real time pricing through negotiated model development and successful customer pilot of hourly day ahead pricing. Educated and trained corporate personnel on pricing strategy, positioning and tactics.

Developed and implemented successful responses to competitive retention challenges with several major customers. Developed alternative long-term contracts and pricing terms to retain or expand customer base. Designed new product prices for non-core services and products. Designed an individual customer profitability model to segment customer retention strategies and differentiate customers.

Resource Planning

Developed models utilized to predict short and long term electric and steam sales and revenues for all classes of customer. Developed DSM business plans by assessing the most profitable opportunities from a business rather than regulatory framework, and devised a strategy for regulatory filings supporting the business plan. Led a statewide utility team that successfully negotiated a collaborative development of generic DSM programs with non-utility parties. Developed a long term DSM evaluation methodology that was adopted by the state regulators. Efforts gained a national reputation in the industry.

Designed and managed residential and business equipment and attitude surveys used to support the development of long term forecasts. Researched customer satisfaction surveys utilized in customer service improvements and as management incentive assessments.

EDUCATION

MBA, Northeastern University, 1987
BS, Mathematics and Economics, University of Massachusetts, 1976

AFFILIATIONS

Director (1996-2000) and member, Association of Energy Services Professionals
Member of Power Marketing Association

SPEECHES & PUBLICATIONS

Cooperative Restructuring Issues, Paper presented at the 10Th National Energy Services Conference, Tucson, AZ, December, 1999

Several *Industry Restructuring* speaking engagements.

Issues and Trends in Pricing, Professional Pricing Society, Annual Conference, Chicago, IL, October 1995.

Selling Evaluation, Sixth International Energy Program Evaluation Conference, August 1993. Published.

A Brief History of a Measurement and Evaluation Department: Boston Edison Company, Edison Times, IRP Quarterly, April 1993.

Competition in the Energy Markets and its Impact on IRP, National Association of Regulatory Utility Commissioners (NARUC), May 1993.

Managing Evaluations, ACEEE Summer Study Program 1992. Published.

Several *DSM* speaking invitations, 1985 - 1994.

Several *Forecasting* speaking invitations, 1980 - 1984.

Numerous publications on such subjects as *Demand Planning Process, Conservation and Load Management, DSM Monitoring, Evaluation,* and *Forecasting and Business Planning.*

ROBERT D. GRENEMAN, P.E.

Associate Director

A licensed professional engineer with a background in engineering economics and public utility rate and regulatory matters, including cost-of-service studies. Experience also includes electrical design work with responsibility for the design and engineering of power distribution, lighting, and signal systems for various projects.

PROFESSIONAL EXPERIENCE

1986 - Present & 1978 - 1982	Stone & Webster Consultants, Inc. Associate Director
1983 - 1986	The Brooklyn Union Gas Company Senior Rate Engineer
1973 - 1978	Alan J. Schultz, Consulting Engineer Associate Engineer
1971 - 1973	Ebner-Schmidt Associates, Consulting Engineers Electrical Design Engineer

CONSULTING ASSIGNMENTS

Cost of Service and Rate Design

Alpena Power Company	*Cost of Service, Rate Design*
Artesian Water Company	*Cost of Service*
Barbados Light & Power Company, Ltd.	*Cost of Service, Rate Design*
Blackstone Valley Electric Company	*Marginal Cost*
Brockton Edison Company	*Marginal Cost*
Brooklyn Union Gas Company	*Cost of Service, Marginal Cost, Rate Design*
Centra Gas British Columbia	*Rate Design*
Central Illinois Light Company	*Cost of Service, Marginal Cost, Rate Design*
Chesapeake Utilities (Maryland Division)	*Gas Cost of Service*
China Light & Power Co., Ltd. (Hong Kong)	*Review of Cost of Service & Tariff Structure*
Citizens Utilities Company (VT, AZ)	*Electric Cost of Service, Rate Design*
Citizens Utilities - Illinois Water	*Water & Wastewater Cost of Service, Rate Design*
Colorado Electric (West Plains Energy)	*Marginal Cost*
Commonwealth Edison Company	*Electric Cost of Service*
Consolidated Edison Company of NY	*Fully-Unbundled Electric, Gas & Steam Models*

Dayton Power & Light Company	*Gas Cost of Service*
Delmarva Power & Light Company	*Electric Cost of Service*
Delta Natural Gas Company	*Cost of Service, Rate Design*
Edison Sault Electric Company	*Cost of Service, Rate Design*
El Paso Electric Company	*Marginal Cost*
Energy North, Inc.	*Rate Design*
Equitable Gas Company (Pittsburgh PA)	*Cost of Service*
Fall River Electric Light Company	*Marginal Cost*
Federal Energy Administration	*Marginal Cost Pricing*
Florida Public Utilities Corporation	*Cost of Service (Electric, Gas)*
Gas Del Estado (Argentina)	*Cost of Service for Privatization Study*
Gaz Metropolitain, Inc. (Montreal)	*Cost of Service*
Green Mountain Power Company	*Cost of Service*
Guyana Electricity Corporation	*Marginal Cost, Rate Design*
Holyoke MA (Department of Gas & Electric)	*Cost of Service*
Jamaica Water Supply Company	*Cost of Service*
Lake Superior District Power Company	*Cost of Service*
Louisville Gas and Electric Company	*Electric Cost of Service*
Midland Electric Power Cooperative (IA)	*Support for Cogeneration Standby Rate*
Montana-Dakota Utilities Company	*Marginal Cost*
New Jersey Board of Public Utilities	*Rate Initiatives to Lower Summer Peak Demand*
Newport Electric Corporation	*Cost of Service*
Newtown Artisian Water Company	*Development of Continuing Property Records*
Northern Indiana Public Service Company	*Fully-Unbundled Electric Cost of Service*
Oklahoma Natural Gas Company	*Review of Main Extension Policy*
Philadelphia Gas Works	*Allocation of Costs to Electric Marketing Initiative*
Riverbay Corporation (Co-op City)	*Rate Case Intervention*
Roseville Electric (Roseville CA)	*Fully-unbundled & Marginal Cost of Service*
South Jersey Gas Company	*Cost of Service*
Southern Indiana Gas & Electric Co.	*Electric/Gas Cost of Service, Rate Design*
Southwest Louisiana Electric Membership Corp.	*Fully-unbundled Cost of Service*
Suffolk County Water Authority	*Cost of Service, Rate Design*
Tampa Electric Company	*Cost of Service*
U.S. Dept. of Energy/PSE&G	*District Heating Rates*
Valley Gas Company	*Cost of Service, Rate Design*
Vermont Public Service Board	*Cost of Service & Rate Advisory*
Washington Natural Gas Company	*Cost of Service*
Westfield, MA (City of)	*Cost of Service, Rate Design*
Winnipeg Hydro	*Cost of Service Review*

Expert Testimony

Delaware Public Service Commission	Docket No. 829 (Cost of Service)
Federal Energy Regulatory Commission	Docket No. ER-81-557-000 (Cost of Service)
Indiana Utility Regulatory Commission	Cause No. 35780-S4 (PURPA Compliance)
Indiana Utility Regulatory Commission	Cause No. 39593 (Gas Cost of Service)
Indiana Utility Regulatory Commission	Cause No. 39671 (Electric Cost of Service)
Indiana Utility Regulatory Commission	Cause No. 40283 (Gas Cost of Service)
Indiana Utility Regulatory Commission	Cause No. 41746 (Electric Cost of Service)
Indiana Utility Regulatory Commission	Cause No. 42150 (Environmental Tracker Support)
Indiana Utility Regulatory Commission	Cause No. 42151 (Purch. Power Tracker Support)
Iowa Utilities Board	Docket No. FCU-99-3 (C-99-76) (Standby Rates)
Kentucky Public Service Commission	Case No. 90-342 (Cost of Service)
Louisiana Public Service Commission	Docket No. U-17735 (Rate Design, Cost of Service)
Michigan Public Service Commission	Case Nos. U-6354 & U-6434 (Cost of Service)
Montana Department of Public Utilities	Docket No. 95.6.____ (Marginal Cost)

Plant Inspections for Bond Indenture Requirement

Orange & Rockland Utilities
Jamaica Water Supply Company

Annual/Consultants Reports

Energy Services of Pensacola
Philadelphia Gas Works

RELATED BACKGROUND

Costing, Pricing and Ratemaking

Actively involved in electric industry restructuring assignments including, preparation of fully unbundled cost of service study models, unbundled rate alternatives and myriad other issues associated with electric deregulation.

Developed cogeneration rates, load retention rates and strategies. In conjunction with a comprehensive review of the tariff system for China Light & Power Company, focused on ways of structuring rates to retain industrial load that was closing operations, moving out of the service territory or installing self-generation. Developed unbundled cost of service study for the Barbados Light & Power Company and advised client as to recommendations for changes to rate structure with an objective of retaining industrial customers that are considering self-generation. Prepared unbundled electric and gas cost of service studies for Southern Indiana Gas and Electric Corporation that were heavily relied on in developing new projects and successfully attracting new business to the service territory, including an automobile assembly plant.

Developed a power adjustment clause for Southwest Louisiana Electric Membership Corporation and adopted as a model for use by cooperatives within the state of Louisiana. Developed an operation and maintenance adjustment clause mechanism for Alpena Power Company, and automatic adjustment clauses for the Guyana Electricity Corporation to adjust rates for changes in foreign exchange, fuel, labor, and inflation. Provided support Northern Indiana Public Service Company for purchased power and environmental trackers. Compiled an industry survey of characteristics of gas adjustment clause mechanisms of responding utilities in the U.S. and Canada to be presented to the American Gas Association.

Prepared a Glossary of Rate and Regulatory Terms; investigated the costs associated with implementation of time-of-day metering; compared the effects of master metering and individual metering on utility load and revenues; and analyzed the impacts of automatic fuel adjustment clauses on revenues in conjunction with the Public Utility Ratemaking Guidelines Project for the U.S. Department of Energy.

Conducted research for a report on The Evolution of Cost Allocation Methodologies Employed by the FPC and FERC (gas pipelines) in conjunction with providing rate case support for Pan-Alberta Gas, Ltd.

Conducted water system costing and pricing studies including work for a large New York water a authority with over 300,000 customers.

Participated in a comprehensive review of the main extension policy for Oklahoma Natural Gas Company including cost of extensions and recommendations for change on policy and practices to encourage new load.

Valuation

Prepared pro forma income and rate base statements for clients in valuation efforts in connection with the potential acquisition of utility and other business assets.

Organizational Studies

Conducted an investigation of the organization, structure and operation of the rate department of a major Northeast combination utility. Focused on the gas ratemaking function as part of a study to determine if gas should operate as separate business unit from electric.

Power Contract Analysis

Conducted an analysis of a proposed negotiating plan by Westvaco Corporation to modify an electric service agreement with the Potomac Edison Company for purchase and sale of power from Westvaco's Luke Mill Plant.

Energy Procurement

Participated in a study concerning the Niagara Power Project in which Vermont, Pennsylvania and Ohio were competing for a 30-MW block of low-cost hydro power from the Power Authority of the State of New York. Performed load forecasting and research, including coal reserve data for report to show why Vermont could derive the greatest economic benefit.

Load Forecasting

Performed a load forecast for a proposed 650-MW, combined-cycle plant in Georgia, Vermont. Analysis of Vermont's present installed capacity, joint ownership in out-of-state units, and future purchased power agreements versus peak-load forecasts for the state.

Feasibility Studies

Participated in a study to determine the economic feasibility of constructing a 40-MW electric generating plant in Vermont, using wood chips obtained from the state's rough and rotten trees as fuel.

Marketing Studies

Performed an analysis of local market conditions for the disposal of flue gas desulfurization by-products for a major northeastern utility. Conducted research and interviews to determine current and forecasted supply/demand

characteristics for five potential by-products. Recommended which product had the most favorable market for absorption of continuing supplies.

Energy Audits and Electrical Load Surveys

Conducted a study for Riverbay Corporation to determine the quantity of heat generated by its steam plant and transferred for sale via a high-temperature, hot-water system to six nearby public schools. Compared cost with current price of this service to the New York City Board of Education.

Conducted electrical load surveys and cost analyses to determine reasonable charges to be paid for electricity by a customer in billing disputes involving the utility, or the landlord in the case of submetered properties. Clients included Radio New York Worldwide (WRFM), Wometco WWHT, Inc., Key Food Supermarkets, Morningside Heights Housing Corporation, Pavlo Engineering Company, A7A Graphic Arts Studio, Inc. and Fisher Brothers Management Company.

Electrical Systems Design

Responsible for design and engineering of electrical systems including power distribution, lighting, and signal systems for various commercial and educational facilities.

EDUCATION

The City College of New York, Bachelor of Engineering - Electrical, 1970

REGISTRATION

Professional Engineer - State of New York
Professional Engineer - State of New Jersey

AFFILIATIONS (past and present)

American Water Works Association
Institute of Electrical & Electronic Engineers
New York Academy of Sciences
Mensa

ARTICLES & PRESENTATIONS

"A Determination of Fire Hydrant Rental Fees," presentation at the 16th Annual Legislative Dinner of the Long Island Water Conference.

"Utility Rate Design and Structure," *Skylines*, August 1983 (Building Owners & Managers Association).

"Preparing for a Rate Case" and "Electric Utility Cost of Service", Presentation at a General Electric Company Seminar. Schenectady, N.Y., June 1992

"Gas Cost of Service and Rate Design in a Deregulated Environment", Presentation at a joint conference of the American Gas Association (AGA) and the Mexican Natural Gas Association (AMGN) in Mexico City, March 28, 1996.

Speaker on "Gas Cost of Service" and "Gas Marginal Costing" at Stone & Webster's Utility Management and Development Program.

"Setting Up Your Cost Models", Presentation at the INFOCAST Functional Unbundling Program. Chicago, IL, November 2000.

DAVID F. DESLAURIERS

Manager

BACKGROUND SUMMARY

Management consultant to the utility and energy industry with comprehensive experience in industry restructuring, regulation, economics, and retail market issues. Expertise includes: business strategy and quantitative decision support services, energy procurement management services, regulatory affairs and policy, financial forecasting and modeling, competitive assessments, rate unbundling and other rate matters, and other services related to the competitive retail energy markets. Expertise includes power, natural gas, and water industries. Experienced in providing full regulatory support services including expert testimony, regulatory strategy, and quantitative support tools. Expert financial modeling skills related to energy and utility industry.

PROFESSIONAL EXPERIENCE

1997-Present	**Stone & Webster Consultants, Inc.** Sr. Consultant, Markets, Finance & Regulation, Boston, MA
1990-1996	**The Columbia Group, Inc.** Sr. Consultant, Rates & Regulatory Affairs Division, Boston, MA

EDUCATION

- MBA, Finance, *Awarded With Distinction*, Babson College Graduate School of Business Management, Wellesley, MA, 1990
- BA, College of the Holy Cross, Economics, Worcester, MA, 1985

SPEECHES AND PAPERS

- Aggregation Insights into the Competitive New England Energy Market, paper presented at 10th National Energy Services Conference, Tucson, AZ, December 1999. Sponsored by *Association of Energy Services Professionals International, Association of Professional Energy Managers, Edison Electric Institute, and Electric Power Research Institute.*
- "What Every Smart Customer Needs to Know About Billing and Retail Settlement", *INFOCAST,* The New Rules of the Game: Taking Advantage of Electricity Choice in Pennsylvania and New Jersey, June 1998, Philadelphia, PA

- "Buying Electricity in the Future--Easier or More Difficult?", *Edison Electric Institute*, National Accounts Workshop, September 1997, Washington, DC

CONSULTING ENGAGEMENTS

Electric Industry Restructuring Projects

Strategic Services for Competitive Electric and Natural Gas Commodity Purchasing Programs- 1999

Retail Load Aggregation Program-a New England Based Group of Cities and Towns

Provided strategic and technical consulting services to the *Rhode Island League of Cities and Towns* and developed a successful large scale retail competitive energy procurement plan entitled "The Rhode Island Energy Aggregation Program" or "REAP". Provided wide range of strategic, advisory, and technical services that led to participation level of nearly 190 million kWh from local government accounts in the state of Rhode Island. Specific activities included facilitating consensus definition of needs and program objectives, regulatory intervention, monitoring, and communication, RFP development and other retail procurement tools, retail electric market and regulatory analysis, load definition and description, economic and rate analysis, contract negotiation, marketing and outreach services. Project requires in-depth knowledge of New England regulatory and competitive retail market climate and familiarity with local government decision making processes and group dynamics.

Competitive Purchasing of Natural Gas for Local Government Agency

Currently spearheading an effort to assist the *Rhode Island Public Transit Authority* to establish a competitively supplied natural gas purchasing program for its fleet of natural gas powered buses and its operating facilities. Facilitated goal and objective setting process and developed RFP for competitively supplied retail level natural gas. Project requires keen understanding of competitive natural gas markets and local government operations. Currently assisting in the review of responses to RFP and the selection of winning bidder for program.

Strategic, Regulatory, and Legislative Activity Projects- 1997-1999

Mid-Sized West Coast Municipal Electric Utility

Conducted a strategic review of electric utility's electric restructuring options. Assisted in development of competitive assessment leading to recommendations for services and pricing in competitive electric markets. Conducted in depth cost studies and led review of utility's stranded costs.

Evaluated options to recover stranded costs and recommended unbundled rate and stranded cost recovery mechanisms.

Southeastern Electric Cooperative Utility
Prepared electric restructuring filing for mid-sized electric cooperative in Louisiana. Filing presented unbundled cost of service analysis and proposed restructuring positions which addressed Louisiana Public Service Commission restructuring orders. Worked with clients to examine impact of various policies itemized by the LPSC and prepared comments filed with LPSC outlining restructuring positions.

Southeastern United States Electric Utility
Currently providing strategic decision making support to southeastern utility facing electric industry restructuring. Assisting in the facilitation of a consensus based strategic and qualitative evaluation of industry restructuring options available to the utility. Employing numerous policy, management review, and business planning techniques to build to a future vision consensus for the utility. Building quantitative business decision analysis model which forecasts financial impacts upon utility of various business direction alternatives

Rockland Electric Company (NY) on behalf of New Jersey Board of Public Utilities
Critically evaluated the rate unbundling filing of large New York-based electric company with service territory in New Jersey. Critiqued company's unbundled rates filing for completeness and compliance the New Jersey Board of Public Utility's order addressing electric industry restructuring. Provided recommendations for modification to filing and accompanying proposed rate design to achieve improved compliance with Board restructuring policy and other appropriate ratesetting and restructuring standards. Submitted report on findings to Board and presented expert written and verbal testimony before Board in support of recommendations.

New England Municipal Utility- Electric Restructuring Quantitative and Qualitative Support
Prepared a comprehensive business planning and forecasting model for utility to be used as a management decision analysis tool within context of restructuring strategic planning framework. As a scenario-based financial forecast, the model determines the impact of numerous distinct restructuring planning scenarios to each of the utility's separate business units and on a system wide basis. Model also contains an unbundled rate analysis, which calculates the separate unbundled cost levels of the utility's electric rates for each scenario and a sensitivity analysis which provides a detailed review of the relative dynamic financial and rate impacts of each scenario. Results of the model will be used to inform qualitative strategic planning process for utility.

Conducted focus groups with utility personnel designed to stimulate discussion and strategic thought around the important electric restructuring issues to the utility.

Strategic Restructuring Analysis and Legislative Support- Iowa Association of Electric Cooperatives
Currently assisting in an electric industry restructuring task force comprised of member cooperatives to develop an electric restructuring strategic plan and joint restructuring position. Assisting in the development of electric restructuring position statements for the association and in the formulation of draft legislation to be presented to the state legislative body. Assisting also, in providing qualitative support services designed to assist the association with negotiations with other electric restructuring stakeholders in the state.

New England Municipal Utility
Assisted in the preparation of unbundled electric cost of service study and accompanying unbundled rates for New England municipal utility. Assisted in the identification, separation, and allocation of costs between utility's steam and electric facilities. Model separates costs between the utility's gas, steam, and electric operations and then unbundles electric operations costs. Calculated demand allocation methodologies and overall cost shifts between gas, electric, and steam operations as a result of unbundling. Provided recommendations as to specific cost allocation as well as unbundled tariff design consistent with electric industry restructuring issues.

Electric Power Industry Projects-International

Economic Optimization Model for Large South American Utility: Luz Del Sur
Prepared an iterative economic optimization model for large electric distribution and generation utility in Lima, Peru, South America. Devised iterative financial model to identify the optimum economic size and loading of conductors and transformers at various system load requirements for the large electric utility. Work conducted within the context of rate setting proceeding before South American regulatory body, which sets rates, based on an ideally sized system model.

Other Electric Power Projects Involving Local Government

Electric Rate Negotiations on behalf of County and City Governments
Examined large mid-Atlantic electric utilities' jurisdictional cost of service study for rate negotiations conducted on behalf of utility's public authority clients comprised of a league of the cities, towns, and counties of two Eastern Seaboard states. Reviewed classification and allocation methodologies, recommended variations in cost of service techniques, and estimated alternative class rates of return. Participated in negotiations on behalf of clients.

Base Rate Filings-Electricity
Conducted full cost of service review of large Mid-Western electric company's first base rate filing after its merge with another retail electric company. Critically evaluated cost of service study and investigated use of cost of service methodology, revenue allocation among classes of service, setting of customer charge, and issues related to retail wheeling. Measured sensitivity of utility cost of service to changes in cost allocation determinants and assumptions. Provided complete litigation support services including conducting of filing analysis and formulating technical litigation positions, preparing written and telephonic discovery, developing of cross-examination questions.

Prepared electric cost of service study for mid-sized Northern New England municipal utility, which was filed before state commission. Drafted expert testimony and assisted in defending filing before commission.

Electric Cost of Service Study Training Program
Developed electric cost of service training models for two New England municipal utilities. Presented and developed models in dynamic interactive setting. Investigated use of alternative cost allocation methodologies and rate design proposals.

Natural Gas Industry Restructuring: Planning, Regulatory, and Rate Support

Natural Gas Pipeline FERC Filings
Assisted in the review of rate filing of major natural gas pipeline before FERC on behalf of large mid-western natural gas concern. Analysis focusing upon cost of service and rate design and issues related to the pricing of new services as the natural gas markets reshape.

Natural Gas Rate Unbundling
Determined cost based firm transportation rate for two municipal gas utilities. Estimated amount of revenue and consumption change due to implementation of rate. Developed unbundled tariffs and created new balancing terms and conditions.

Prepared specialized rate for high load factor customers of a large municipal gas utility.

Long Range Gas Supply Plan
Prepared long range load forecast for large municipal gas utility. Evaluated and forecasted peak day and annual requirements. Developed econometric model to forecast load. Built regression equations to forecast peak day load and derived load curves. Analyzed future gas supply options in terms of cost, reliability, and feasibility. Conducted sensitivity analyses, which measured

effects of changes in planning assumptions upon peak day and annual requirements

Gas Supply Planning and Management
Critically reviewed several purchased gas adjustment clauses of investor owned natural gas utilities including rulemaking proposals to unbundle the PGA. Prepared PGA rulemaking recommendations designed to improve the way in which gas costs are recovered. Issues included peak day planning, setting of reserve margins, evaluation of balancing rates, and treatment of producer reservation fees. Non-traditional issues included treatment of capacity release and off-system sales revenues, incentive ratemaking, use of hedging techniques, and competitive aspects of the natural gas industry.

Incentive Based Ratemaking Program Reviews-Natural Gas
Critically reviewed proposed incentive based ratemaking program of major Southeastern investor-owned gas utility and developed recommendations to improve program and ratemaking process. Evaluated risk allocation between shareholders and ratepayers and the proper setting of benchmark.

Gas Contracting Reviews
Reviewed over 100 post-Order 636 gas supply contracts of the investor-owned utilities in the Commonwealth of Massachusetts. Analysis focused upon proper pricing, supply assurance and reliability, contract flexibility, and other terms and conditions. Evaluated use of incentive ratemaking for companies involved.

Gas Prudence Reviews
Conducted a gas prudence review of investor-owned natural gas utility. Evaluated prudence of Company's long term gas contracts with its affiliate producer.

Natural Gas Retail Rates
Conducted full cost of service and rate design analysis of over 50 investor-owned natural gas, electric, and water utility base rate filings. Analyses focused upon cost of service methodology, rate design including customer charges, allocation of revenue increase, and policy and rate design issues relating to emerging utility competition.

Developed financial models, which determined sensitivity of utility cost of service to changes in cost allocation determinants and assumptions.

Provided complete litigation support services including conducting of filing analysis and formulating technical litigation positions, preparing written and telephonic discovery, developing cross examination questions, drafting written expert testimony, and providing oral expert testimony.

Water and Wastewater Projects: Planning, Regulatory and Rate Support

Retail and Wholesale Rate Design
Performed annual updates to retail water and wholesale water cost of service studies of large mid-Atlantic municipal utility. Developed wastewater cost of service study for Utility and updated annually.

Prepared cost of service analysis and revised rate design for mid-sized New England water utility. Developed and implemented rate design alternatives designed to increase annual load and utility's competitive position. Proposed comprehensive Economic Development Rate program. Delivered presentation to City fathers regarding merits of new rate design. Developed gas and electric cost of service training models for two New England municipal utilities.

Developed wastewater cost of service model for large Mid-Atlantic municipal utility. Made recommendations to change rate design and updated model annually for several years.

Special Rate Development
Developed pro-forma 30-year rates to determine the feasibility of forming a regional water authority. Conducted extensive cost allocation variations, which considered the operating and financial aspects of numerous participating parties.

Water Rate Training Workshops- New England Water Works Association
Providing ongoing training of financial staff members of New England based water utilities on matters pertaining to water utility economics and rate design.

Expert Testimonies

- Rockland Electric Company: Energy Master Plan Phase II Proceeding
- Connecticut Natural Gas Company
- Connecticut American Water Company
- Philadelphia-Suburban Water Company
- Pennsylvania Gas & Water Company- Scranton Division
- Pennsylvania Gas & Water Company- Spring Brook Division
- Pennsylvania Gas & Water Company- Crystal Lake Division

ROGER C. BOUDREAU
Associate Director

Management consultant with diverse experience in the electric utility industry centering on deregulation, state and federal regulatory proceedings and load research. Joined Stone & Webster Consultants with a Bachelors Degree in Electrical Engineering and over 30 years experience that includes distribution engineering, load research, rates, cost-of-service, load forecasting, market research and load profiling.

PROFESSIONAL EXPERIENCE

2000 - Present	Stone & Webster Consultants, Inc. Associate Director
1965 - 2000	Boston Edison Company Manager of Load Research

BACKGROUND

Team Leader, Load Research

- Reestablished the load research program in anticipation data requirements for the deregulation of the electric utility markets.
- Prepared the designs of new load research surveys to improve the accuracy of estimates in the daily load profiling process.
- Designed graphical representations of customer load profiles analyzing annual usage patterns for competitive suppliers.
- Maintained the Company's load research system and trained other departments in load research practices.

Utility Restructuring

- Served as a key advisor on the open access team that prepared the company for all aspects of oncoming deregulation.
- Configured the load research system to perform daily load profiling for open access.
- Participated in the design of a customer data warehouse to be used in support of open access.
- Managed the outsourcing for the development of load research data and allocation factors for the cost-of-service and rate design associated with the company's rate restructuring filing.

Project Manager of Real-Time Pricing Pilot

- Served as project manager for a real time pricing project requiring the coordination, implementation and direction for this pilot program.
- Prepared quarterly reports to the Department of Telecommunications and Energy (DTE) on the results of the pilot program.

Principal Engineer

- Developed new procedures for forecasting peak demands in the company's service territory.
- Contributed to the development of new procedures for customer billing analysis, unbundled services, cost-of-service, rate design, market pricing and load research.
- Primary contributor in the development of real-time pricing policies.
- Acted as team leader in developing a rate case contingency plan and assisted in the management of a "Pricing" plan for the E-Plan filing.
- Prepared annual report for the Massachusetts utility commission detailing the analysis and results of the Generator Assistance Program that was a DSM project designed to reduce system loads during summer peaks.

Manager, Load Research

- Directed the implementation and management of the company's load research programs, cost-of-service studies and system loss studies.
- Managed a technical division with a staff of five to ten professionals working on regulatory requirements.
- Instrumental in the design and implementation of the time-of-use billing process.
- Crafted a load research program that continuously met with Department of Telecommunications and Energy (DTE) approval.
- Served as member and chairman of the Advanced Metering Technology Task Force.

Principle Analyst

- Assumed progressive responsibilities for the data base management and data analysis of load research surveys.
- Participated in the preparation of rate and load research analysis for rate case filings.

- Provided services for data preparation, data analysis and impact evaluation associated with the company's DSM filings.
- Served as chairman of the Time-Of-Use Billing Task Force.

Distribution Planning Engineer

- Conducted advanced engineering studies in technical areas such as transformer life cycles, streetlighting economics and system losses.
- Produced technical reports with recommendations relating to transformer load management and the power factor policies for streetlighting ballasts.

Distribution Engineer

- Provided the network system design and associated distribution engineering for secondary network system in downtown Boston.
- Prepared new business work orders and met with customers and/or contractors to resolve issues relating to the installation of services for network transformer vaults.
- Updated and maintained a computer load flow model of the five secondary networks.

EDUCATION

BS, Electrical Engineering, Northeastern University

PROFESSIONAL AFFILIATIONS

Institute of Electrical and Electronic Engineers, Member

PAUL DAVIS
Associate Director

SUMMARY

Thirty years of industry experience, consistently leading the industry for implementing innovative, forward thinking, business driven methodologies. Proven ability to enhance corporate growth and effect positive change. Earned reputation as project manager with team building skills and a results orientation. Have been at the cutting edge of utility innovation/restructuring for twenty years. Recognized as expert witness in regulatory hearings concerning planning, economics, econometrics, mathematics, statistics, load research, local/regional economics and demand forecasting. Innate ability to separate the wheat from the chaff in technical analyses.

EXPERIENCE

1999 - Present	**Stone & Webster Consultants, Inc.**
1969 - 1999	**Boston Edison Company**

Joined Stone & Webster Consultants in 1999 bringing thirty years of utility experience from NSTAR (Boston Edison) including a multi-year assignment with the New England Power Pool. Extensive experience in distribution planning, metering, load forecasting, load research, demand side management, deregulated market pricing, asset management, and life cycle planning. Participated in much of the deregulation process in Massachusetts and, more recently was part of the transition to an asset management approach to transmission and distribution resource planning.

Life Cycle Plan Manager (1997-1999)

Responsible for the development and management of the $200 million Distribution Electric Delivery multi-year Life Cycle Plan.

Key Accomplishments

- Developed a multi-year detailed capital and O&M plan to which strives to optimize the cost and performance of the distribution assets.
- Coordinated integration steps between Asset Strategy, Investment Planning, and Field Forces to eliminate "blanket" work orders.
- Budget decreased from $200M to $160M over two years and productivity increased so that more work is being done with lower expenditures.

Principal Engineer/Research Analyst (1983 – 1997)

Responsible for establishing analytical methodologies for evaluation of supply-side/demand-side programs for this $1.5 billion electric utility.

Key Accomplishments

- Implemented the U K. market model as a starting point for the free market system for NEPOOL member utilities.
- Analysis and methodological review of the computer program used to review and evaluate the bids in the "first ever" supply options offering for an electric utility.
- Streamlined the analysis of supply side analysis by implementing the PC version of EGEAS and later modified the PROSYM model for long range supply planning.
- Developed a NEPOOL generation database consistent with the Boston Edison database.
- Built an inter-organizational taskforce of nine professionals from Finance, Engineering, Rates, Forecasting, Marketing and System Programming.
- Implemented and made operational the EGEAS (Electric Generation Expansion Analysis System) as a PC based analysis tool with savings of $200, 0001year.

Head, Forecasting & Demand Research Groups (1978 - 1982)

Responsible for short-run, long-range, and sub-regional forecasts of sales. The Company's budget and construction programs are based upon this Group's forecasts. Responsible for setting up the Company's Load Research Group including metering technology, measurement techniques, load shape analysis and statistical methodologies.

Key Accomplishments

- Originated both groups and instituted a multi-disciplinary approach to forecasting.
- Testified before regulatory agencies as an expert witness.
- Secured approval of annual forecasts and market assessment methodologies.
- Results included a $480 million nuclear plant construction cost recovery.
- Managed nine professionals in each group.
- Implemented a planning and activity report system to increase productivity and accountability.

Senior Load Research Analyst (1977 - 1978)

Responsible for implementing forecasting methods at Boston Edison.

Key Accomplishments
- Established market segment forecast.
- Added price response effects to Company forecasts (a first in New England).
- Introduced demographics as an integral part of forecasting.
- Set the criteria for market research data collection.
- Performed as Massachusetts State Model Manager for the New England Power Pool.

Electrical Engineer (1976 - 1977)

Special assignment to the New England Power Pool.

Key Accomplishments
- Worked with a multi-disciplinary taskforce from other utilities, the New England power Pool, and Battelle-Columbus to design and develop a highly disaggregated state of the art long-range forecasting model.

Electrical Engineer (1969 - 1976)

Worked in three different areas during this time period: Distribution, Metering, and Planning.

Key Accomplishments
- Performed a variety of engineering tasks gradually increasing from small projects (under $100K) to larger transmission and distribution projects ($10 million).
- Instituted risk analysis for distribution system.
- Revised the distribution and substation forecasting model that is still used.

EDUCATION

Post Graduate courses in macro, micro and regional economics

Northeastern University, 1974, M.S. Electrical Engineering

University of Massachusetts, 1969, B.S. Electrical Engineering

JOSEPH F. PINO JR.
Manager

Management consultant with diverse experience in the electric utility industry centering on deregulation, state and federal regulatory proceedings and customer billing. Joined Stone & Webster Consultants with a Bachelors Degree in Mathematics and over 20 years experience that includes rates, cost-of-service, demand side management, performance base rates, pricing, billing and information systems.

PROFESSIONAL EXPERIENCE

2002 - Present	Stone & Webster Consultants, Inc. Associate Director
1981 - 2002	NSTAR / Boston Edison Company Manager - Customer Information System

BACKGROUND

Manager, Customer Information System

- Liaison between information systems and business partners.
- Led NSTAR effort during merger of customer information systems.
- Provided support and resources leading up to merger process.
- Managed implementation of supplier billing using EBT/EDI.
- Managed successful Y2K team effort for the Customer Information System.
- Led team responsible for the daily operation and maintenance of the billing system.
- Implemented several tariff changes to billing system.
- Assisted in the creation of new financial and usage reports.

Utility Restructuring

- Implemented new unbundled tariffs for deregulation.
- Developed method of unbundling cost by rate class.
- Participated in the redesign of a customer billing system for deregulation.
- Assisted in development of Performance Based Rates (PBR).
- Separated street lighting revenue and cost to prepare for municipalization.

Pricing

- Served on team responsible for implementing real time pricing pilot.
- Implemented several rate changes.
- Assisted in development of sample performance base rates (PBR) for PUC.
- Created pricing for several special contracts in competitive situations.
- Set policy and pricing on products, services and special contracts.

Demand Side Management (DSM)

- Developed company's first data warehouse to retrieve billing and customer information for DSM related projects.
- Managed several internal consultants in creating DSM information system.
- Managed external consultants in review of several DSM programs.

Information System Analyst

- Provided data and key contributor to meter technical task force.
- Enhanced and supported customer information system.
- Created customer and billing information files for conversion to new system.
- Implemented software for new billing stock on laser printer.
- Enhanced and supported billing system.
- Assisted in training of new personnel.

EDUCATION

BS, Mathematics, University of Massachusetts - Boston

MICHAEL E. GREEN
Executive Consultant
APPRAISAL DIVISION

SUMMARY

Michael E. Green, ASA, is an executive consultant with over nineteen years of experience in the valuation of public utility and railroad property. He has appraised properties owned by natural gas pipelines, natural gas distribution companies, electric utilities, non-utility generators, short-line and regional railroads, private railcar companies, water and sewer companies, and telecommunications companies. His appraisals have been used in buy/sell decisions, ad valorem tax litigation, condemnation proceedings and fraud litigation. He is also a licensed general real property appraiser with experience in the appraisal of office buildings, apartments, shopping centers, industrial properties and various other types of commercial real estate.

Mr. Green is experienced in the preparation of detailed cost of capital studies using standard corporate finance models (Discounted Cash Flow or "Gordon's Model" and the Capital Asset Pricing Model) and "project finance" structures commonly used in the power generation industry. He routinely prepares detailed cost of capital estimates in conjunction with his appraisals and valuation related consulting assignments and has prepared independent cost of capital studies for utility clients in connection with *ad valorem* tax valuation negotiations.

Prior to his association with Stone & Webster Consultants, Mr. Green was employed by John E. Green & Associates, a firm specializing in the valuation of public utility and railroad property and was a sub-contractor to Real Estate Appraisers, Inc. in Montgomery, Alabama.

PROFESSIONAL EXPERIENCE

1998 to present Stone & Webster Consultants
1982 to 1998 John E. Green & Associates
1982 to 1994 Real Estate Appraisers, Inc. (sub-contractor)

PROFESSIONAL LICENSES

Certified General Real Property Appraiser – Alabama License Number G00193
Ohio License Number 448603
Maine License Number CG1266
New York Temporary License through 3/17/03

PROFESSIONAL ASSOCIATION

American Society of Appraisers – Accredited Senior Appraiser

EDUCATION

Master of Business Administration (1986), Auburn University at Montgomery, Alabama

Bachelor of Science in Business Administration-Finance (1982); Auburn University, Auburn, Alabama

Post-Graduate Studies:

Financial Engineering (2000), Auburn University Graduate School of Business, Auburn, Alabama

APPRAISAL EDUCATION

American Institute of Real Estate Appraisers –

Real Estate Appraisal Principles Course 1A-1, 1981
Basic Valuation Procedures Course 1A-2, 1983
Capitalization Theory and Techniques Part A, 1985
Capitalization Theory and Techniques Part B, 1985
Case Studies Course 2-1, 1986
Valuation Analysis and Report Writing Course 2-2, 1986
Standards of Professional Practice, 1987, 1993, 1995, 1997, 2001

Wichita Workshop – Appraisal of Communications, Energy and Transportation Properties for Ad Valorem Taxation

Annual Attendee, 1983 to present
1994, 1995, 1996 and 1998 Planning Committee Member
Speaker 1996, 1997 and 1998

PUBLICATIONS

Green, Michael E. "Application of the Cost Approach to the Appraisal of Electric Power Generating Plants." *Impacts of Electric Utility Deregulation on Property Taxation.* Cambridge, MA: Lincoln Institute of Land Policy, 2000.

Green, Michael E. "Nuclear Power: Appraising Troubled Assets in a Competitive Market", *Journal of Property Tax Management,* Fall 1997. Originally presented at the Wichita Public Utility Workshop in August 1997.

Green, Michael E., "The Effect of Deregulation on the Market Value of Utility-Owned Generating Plants", *Journal of Property Tax Management,* Winter 1998. Originally presented at the IAAO Public Utility Conference in Nashville, TN, in March 1997.

Green, Michael E. and Terrence J. Benshoof, "Exclusion of Intangibles from the Unit Value", *State Tax Notes*, December 16, 1991. Originally presented at the IPT Conference in Sparks, Nevada.

LISA M. VEDDER
Senior Consultant

SUMMARY OF QUALIFICATIONS

Extensive senior-level experience in the energy industry with emphasis on electric and gas industry restructuring. Areas of expertise include regulatory policy, rate-making, technical and financial evaluations of power generation technologies, including alternative fuels, energy contracts and financing of complex sale/leasebacks & swaps.

EDUCATION

HARVARD UNIVERSITY, JOHN F. KENNEDY SCHOOL OF GOVERNMENT, Cambridge, MA
Masters in Public Administration, June 2000
Methodological Areas of Concentration: Negotiation & Conflict Resolution; and Regulation & Industry Analysis

Women's Leadership Initiative Fellow
Harvard Business School courses: privatization, regulation and deregulation (Dyck); capital markets (Froot); and negotiating complex deals and disputes (Wheeler).

Research Assistant to Henry Lee, Jaidah Family Director Environment and Natural Resources Program

UNIVERSITY OF WISCONSIN – MADISON, Madison, WI
BS in Industrial Engineering, December 1984 – Tau Beta Pi, Alpha Pi Mu

WORK EXPERIENCE

July 2000-present *Advisor,* **London Economics International, LLC** – *Senior* **Cambridge, MA**

- Evaluated expected LRMC of CCGT in Central Europe.
- Provided supporting opinion for reasonableness of interest rate for financing of complex sale/leaseback of USD 110 M fixed telcom assets in Belgium.
- Provided supporting opinion for reasonableness of interest rate for financing of future swap transaction linked to revenues from Austrian electricity & gas network assets.
- Provided supporting opinion for reasonableness of interest rate for financing of future swap transaction linked to convention center complex in Germany.

- Researched & reported upon status of EU natural gas and electricity market liberalization.
- Evaluated Transmission Administrator's function, role and incentive structure in support of re-design of Albertan power market.
- Researched and reported upon ISO-NE's proposed Standard Market Design.
- Designed ISO New England's proposed 2001 self-funding tariff including preparation of expert testimony & associated FERC filings.
- Designed proposed 2001 tariff to assure recovery of industry restructuring costs by NEPOOL.
- Provided expertise in the analysis of PBR regimes for a foreign utility.
- Provided project support to clients on a variety of energy industry assignments.

1998-1999 **Economics And Technology, Inc**, *Senior Consultant*, **Boston, MA**

- Provided policy expertise & authored testimony on synergistic benefits of proposed Bell Atlantic/GTE merger to the California PUC's Office of Ratepayer Advocates (CPUC ORA).
- Provided policy expertise to & authored testimony on electric industry unbundling for the CPUC ORA in the 1999 General Rate Case for Pacific Gas & Electric, with particular emphasis on the treatment of costs associated with support of both regulated and non-regulated (competitive) functions.
- On behalf of the Office of Consumer Advocates for the PAPUC, authored comments at the FERC on terms governing natural gas pipeline capacity (RM98-10-000/RM98-12-000).
- On behalf of a mobile telephony provider, in support of litigation, defended award of an international mobile telephony license and supported cross and direct examination.

1993-1998 **LEVITAN & ASSOCIATES, INC.** *Managing Consultant*, Boston, MA

- Served as key member of the transaction team providing analytical and negotiation support that culminated in the termination of NUG power purchase agreements (PPAs) representing nearly $2 billion in ratepayer savings and 1,000 MW of capacity.
- Supported PPA restructuring and securitization analyses on behalf of utilities and other interested parties.
- Performed generation asset valuations, including creation of dispatch models, supporting bids for generation assets auctioned off by utilities in New England.

- Served as the primary author of reports concerning the future outlook for the New England energy market, including consideration of NEPOOL restructuring, the nuclear sector, natural gas pipeline capacity additions and transmission constraints in Eastern REMVEC.
- Performed technical and financial evaluations of waste-to-energy, waste fuel-fired and conventional non-utility generation (NUG) projects.
- Participated in electric industry restructuring proceedings before various state commissions and legislative bodies including the preparation and submission of testimony.
- Provided "all-energy" (electricity, natural gas and fuel oil) procurement services for large industrials and institutional energy users; managed database development activities associated with energy user load profiling, load aggregation and Btu optimization.
- Provided litigation support, participated in discovery, prepared interrogatories and authored testimony.
- Analyzed natural gas supply, transportation and storage contracts and arrangements.

1991-1993, **ROY F. WESTON, INC.,** *Project Manager*, Burlington, MA & Los Angeles, CA

- Served as co-Project Manager for the City of Los Angeles's $1.2 million Solid Waste Generation Study conducted to ensure full compliance with California law AB 939; responsibilities included making formal presentations on behalf of the City to the Board of Public Works and industry and trade groups, training and overseeing staff, and managing ten sub-contractors.
- Conducted technical and economic analyses of solid waste projects and served as primary author for Consulting Engineer's Feasibility Reports for the financing and refinancing of solid waste processing facilities throughout the US.
- Prepared RFPs and RFQs, performed financial and technical evaluations of proposals, and negotiated contracts for solid waste processing, transportation and disposal services on behalf of municipalities and authorities.
- Performed technology assessments, waste stream quantification and composition analyses, and designed and implemented computer-based technical and financial models.
- Designed a proprietary model to calculate landfill dimensions, estimate landfill development and construction costs, and forecast landfill-operating costs in support of feasibility analyses.

1990-1991 Stone & Webster Engineering Corporation
Information Technology Division – *Engineer* Boston, MA

- Developed and supported computerized solutions in various languages, operating systems and platforms for large diverse engineering and construction projects.
- Enhanced and customized the proprietary relational database package ACCESS for the Massachusetts Water Resources Authority's Boston Harbor cleanup.

1986-1990, **CSI RESOURCE SYSTEMS, INC.**, *Associate*, **Boston, MA**

- Analyzed waste stream compositions and quantities, financial arrangements, risk structures, alternative technologies and facility sizing for solid waste projects.
- Provided procurement support for massburn resource recovery facilities, refuse derived fuel facilities, transfer stations, materials recovery facilities, mixed solid waste composting facilities, yard waste composting facilities and curbside recycling services.
- Prepared RFQs and RFPs, evaluated qualifications and proposals in support of vendor selection.
- Supported service agreement negotiation for solid waste management services.
- Prepared Consulting Engineer's Feasibility Reports for the financing of various solid waste processing facilities.
- Monitored construction and Acceptance Testing of various refuse derived fuel and massburn resource recovery facilities in New York, Connecticut, and Florida.

1985-1986, DYNAMICS RESEARCH CORPORATION, *Operations Research Engineer*, Wilmington, MA

- Designed and integrated a computer simulation model for interface with an existing Materials Requirements Planning (MRP) package.
- Developed a production control module for the Mita-5 gyroscope and integrated this module into the existing MRP package.
- Designed procedural protocols for maintenance and use of magnetic media attached to missile guidance systems. Generated flow charts for components of the MK6 guidance system accelerometer and Mita-5 gyroscope.

PUBLICATIONS

Lee, Henry and Shashi Kent Verma, "Coal or Gas: The Cost of Cleaner Power in the Midwest," BCSIA Discussion Paper 2000-08, ENRP Discussion Paper

E-2000-08, Kennedy School of Government, Harvard University, June 2000 (air pollution section).

REFERENCES

Available upon request.

SPECIAL SKILLS/PERSONAL

Registered Engineer-in-Training in MA

Travel: Traveled extensively throughout the UK, Ireland, Europe, North Africa, New Zealand and South America

Activities: Racing Sailboats, US Sailing Registered Keelboat Instructor #616, fishing and biking.

Appendix 2 Contract Standard

TERMS & CONDITIONS OF CONSULTING ASSIGNMENTS

1. *Scope* - Stone & Webster Consultants, Inc. ("Stone & Webster Consultants") will perform the services set forth in the Letter or Proposal of which these Terms and Conditions ("Terms") are a part and together make up the "Agreement." The provisions of these Terms shall control in the case of conflict with any provisions of the Letter or Proposal or any other contract document.

2. *Fees and Expenses* - Fees: Unless otherwise stated, fees for services provided by Stone & Webster Consultants shall be based upon the rates, at the time the work is performed, of the personnel actually involved in the assignment. Expenses: Report production and printing, reproduction, telephone and computer services will be billed to you at Stone & Webster Consultants' standard charges for such materials or services. Expenses of consultants while on assignment or any other charge incurred or expenditure made on your behalf will be charged at our cost.

3. *Payment* - Stone & Webster Consultants will submit monthly invoices reflecting actual work performed and expenses incurred. Payment shall be due 15 days after the date of an invoice. Amounts past due more than 30 days shall bear interest from the due date until payment is received. The rate of interest applicable during a calendar month shall be the Prime Rate (or in the event a range of Prime Rates is published, the mean of such range) as published in the Eastern Edition of The Wall Street Journal on the first business day of each month that the amount is outstanding. In addition to all other available remedies, Stone & Webster Consultants may, at its option, stop work or terminate the Agreement in the event there is an unpaid balance due for more than 30 days.

4. *Insurance* - Stone & Webster Consultants will maintain comprehensive general and automobile liability insurance with a combined bodily injury and property damage limit of $300,000 and worker's compensation insurance as required by law.

5. *Independent Contractor* - It is understood and agreed that Stone & Webster Consultants shall for all purposes be an independent contractor, shall not hold itself out as representing or acting in any manner for you, and shall have no authority to bind you to any contracts or in any other manner.

6. *Termination* - This Agreement shall be subject to the right of either party to terminate at any time upon not less than ten (10) days' prior written notice to the other party. Upon termination, you shall pay the full amount due for services rendered and costs and expenses incurred and not paid for up to that time, and the costs of returning consultant personnel to home base and other reasonable costs and expenses incurred in effecting termination (including cancellation charges) and returning documents.

7. *Responsibility Statement* - Stone & Webster Consultants' services will consist of reviewing and advising you concerning the subject project and/or facilities for which Stone & Webster Consultants has no engineering, design, construction, operation or maintenance responsibility. Stone & Webster Consultants' review of any information prepared by you or others, including, but not limited to, design, schedule, interface, environmental, permitting, performance, market or economic information, shall in no way serve to transfer to Stone & Webster Consultants responsibility or liability for the accuracy, correctness, or timeliness of such information. Such information shall be timely submitted to Stone & Webster Consultants and Stone & Webster Consultants' advice will be based on and limited by the accuracy, scope, and timeliness of information furnished to Stone & Webster Consultants. Time and scope limitations inherent in Stone & Webster Consultants' performance preclude definitive verification of factors, which may later be shown to have been important to the project. Stone & Webster Consultants' review, therefore, may not uncover all of the significant risks and variables. The parties acknowledge that the actual project economic viability and technical performance depend on many factors not within the control of Stone & Webster Consultants, such as proper design, equipment, construction, operation, maintenance, etc. Therefore, Stone & Webster Consultants specifically does not guarantee, warranty or otherwise underwrite the project, its economic viability or its technical performance. Any engineering, design, construction, operation or maintenance deficiencies shall remain the complete responsibility of the party or parties providing the engineering, design, construction, operation and maintenance services for the project. It is understood that Stone & Webster Consultants shall have no right of authority to stop any work, nor shall Stone & Webster Consultants have any responsibility for the means, methods, techniques or safety programs of the engineer, constructor and/or operator. Stone & Webster Consultants' services are provided for your sole benefit and not for the benefit of or use by any other party. No third party shall be entitled to rely upon Stone & Webster Consultants' work product.

Stone & Webster Consultants agrees that the services provided for herein will be performed in accordance with recognized professional consulting standards for the same or similar services. If, during the performance of these services or within one year following completion of the assignment, such services shall prove to be faulty or defective by reason of a failure to meet such standards, Stone & Webster Consultants agrees that, upon prompt written notification from you of any such fault or defect prior to the expiration of the one-year period following the completion of the services, such faulty or defective portion of the services shall be redone to meet such standards at no cost to you up to a maximum amount equivalent to the cost of the services rendered under this assignment. If the foregoing remedy is not appropriate or suitable under the circumstances, Stone & Webster Consultants shall be liable to you for any extra costs or damages incurred or suffered by you as a direct result of such fault or defect up to 50% of the amount of the fees for services received by Stone & Webster Consultants for this assignment, and this shall be your exclusive remedy.

Notwithstanding any other provision to the contrary in this Agreement, Stone & Webster Consultants' total aggregate liability to you for damages suffered by you under this Agreement shall be limited to 50% of the amount of the fees for services received by Stone & Webster Consultants under this Agreement or, for Stone & Webster Consultants' liability for which there is insurance coverage explicitly set forth in this Agreement, Stone & Webster Consultants' liability shall be limited to the proceeds up to the specific limits of any applicable insurance coverage explicitly set forth in this Agreement. In no event shall Stone & Webster Consultants, its parent corporation, or its or their affiliates, agents, employees, or others providing materials or performing services in connection with this Agreement be liable for any other direct, or for any indirect, incidental, consequential or special loss or damage, whether attributable to breach of contract, warranty, express or implied, tort, including negligence, strict liability, or otherwise. Except as herein provided, you release, indemnify and hold harmless Stone & Webster Consultants, its parent corporation and its and their affiliates, agents, employees, or others providing materials or performing services in connection with this Agreement from and against any and all liability, as well as costs of defense, settlement and reasonable attorney's fees, irrespective of fault or negligence, except where such liability arises out of "gross negligence" or willful misconduct on the part of Stone & Webster Consultants or its assignment personnel or both. "Gross negligence" means any act that was performed with the wanton and reckless indifference and disregard to the harmful consequences on the safety or property of another person or entity.

8. *Confidential Information* - Neither party shall disclose to any third party any Confidential Information of the other, and such Confidential Information shall be identified or marked as confidential at the time of disclosure, for a period of two (2) years after completion of this Agreement. As used herein, Confidential Information includes, but is not limited to, any information that relates to any party's research, development, trade secrets, proprietary products or business affairs, but does not include information that (i) is at the time of its disclosure publicly known or becomes publicly known through no breach of the terms of this Agreement; (ii) was already known by the receiving party at the time of disclosure; (iii) is lawfully received from a third party not bound under a confidentiality agreement with either party; or (iv) is disclosed under legal compulsion. This paragraph 8 shall survive expiration or termination of this Agreement.

9. *Work Product* - Any report or other document prepared pursuant to this Agreement shall be for your use only. Stone & Webster Consultants' prior written consent is required for the use of (or reference to) its report or any other document or information prepared pursuant to this Agreement, including use in connection with a public offering of securities or in connection with any other financing. It is understood and agreed that Stone & Webster Consultants' use of its proprietary computer software, methodology, procedures or other proprietary information in connection with an assignment shall not give you or anyone else any rights with respect to such proprietary computer software, methodology, procedures or other proprietary information, and you agree to keep confidential and not disclose such proprietary information to any third parties. Subject to the confidentiality obligations hereunder, Stone & Webster Consultants may retain and further use the technical content of its work hereunder. This paragraph 9 shall survive termination or expiration of this Agreement.

   The following legal notice shall be affixed to any report or other document furnished by Stone & Webster Consultants hereunder and to any report or other document resulting from this Agreement which may be distributed outside your organization.

"LEGAL NOTICE"

This document was prepared by Stone & Webster Consultants, Inc. ("Stone & Webster Consultants") solely for the benefit of _____. Neither Stone & Webster Consultants, nor parent corporation or its or their affiliates, nor _____, nor any person acting in their behalf (a) makes any warranty, expressed or implied, with respect to the use of any information or methods disclosed in this document; or (b)

assumes any liability with respect to the use of any information or methods disclosed in this document.

Any recipient of this document, by their acceptance or use of this document, releases Stone & Webster Consultants, its parent corporation and its and their affiliates, and _____ from any liability for direct, indirect, consequential or special loss or damage whether arising in contract, warranty, express or implied, tort or otherwise, and irrespective of fault, negligence, and strict liability."

10. *Excused Performance* - Stone & Webster Consultants shall not be deemed in default of any provision hereof or be liable for any delay, failure in performance, or interruption of service resulting directly or indirectly from a force majeure event, including but not limited to acts of God, civil or military authority, civil disturbance, war, strikes or other labor disputes, fires, other catastrophes, or other force, event or condition beyond its reasonable control, whether or not such event may be deemed foreseeable.

11. *Notices* - All notices and communications given under or pursuant to the Agreement shall be in writing and sent by certified mail, telecopied or delivered to Stone & Webster Consultants, Inc. at 1430 Enclave Parkway, Houston, TX, 77077, Fax: 281-368-4491, Attention: General Counsel, and if to Client at the address or telecopy number shown on the Letter or Proposal or such other address or telecopy number as Client may designate by written notice to Stone & Webster Consultants. All such notices and communications shall be effective: (a) if mailed, when received, as evidenced by a Return Receipt; (b) if telecopied, when sent, as evidenced by receipt of a confirmation from the correct telecopier number; and (c) if delivered personally or by courier, when actually received as evidenced by a receipt.

12. *Complete Agreement* - It is understood and agreed that this Agreement embodies the complete understanding of the parties and that any and all provisions, negotiations and representations not included herein are hereby abrogated and these Terms cannot be changed, modified or varied except by written instrument signed by both parties. In the event you issue a purchase order or memorandum or other instrument covering the services herein provided, it is hereby specifically agreed and understood that such purchase order, memorandum, or instrument is for your internal purposes only, and any and all terms and conditions contained therein, whether printed or written, shall be of no force or effect unless agreed to in writing and signed by Stone & Webster Consultants. No waiver by either party of a breach hereof or a default hereunder shall be deemed a waiver by such party of a subsequent breach or default of like or similar nature.

13. *Governing Law* - This Agreement shall be construed and otherwise governed pursuant to the laws of the Commonwealth of Massachusetts, excluding the conflicts of laws principles, and the parties agree to the jurisdiction of the courts of said state.

14. *Dispute Resolution* - The parties shall make a diligent, good faith attempt to resolve by negotiation all disputes arising out of or in connection with this Agreement. If such negotiation is unsuccessful within a period of forty-five (45) days, the parties shall make a diligent, good faith attempt to settle the dispute by mediation pursuant to the American Arbitration Association's Commercial Mediation Rules, except as excluded or varied by this Agreement. If such mediation is unsuccessful within a reasonable period of time, either party may submit any unresolved dispute to arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association. Any such arbitration shall be conducted in Boston, Massachusetts, by the Regional Office of the American Arbitration Association. Any award less than $500,000 shall be final and binding, and may be entered into a court of competent jurisdiction for enforcement. Any award of $500,000 or greater may be appealed to any state or federal court in Massachusetts for a trial de novo.

Each party shall be responsible for its own costs and expenses, including legal fees, incurred in the course of any arbitration or legal proceedings. The fees of the arbitrators shall be shared equally by the parties. The arbitrators shall be bound by the terms of this Agreement and shall not have the power or authority to award costs, expenses, attorney's fees, punitive damages, or consequential damages.

Stone & Webster Consultants, Inc.
1430 Enclave Parkway, Houston, TX 77077-2023
Tel: 281-368-4460 Fax: 281-368-4484/4488/4491

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At Stone & Webster Consultants, a century of experience, an unparalleled network of technical and managerial expertise, and a tradition of quality and integrity stand behind comprehensive consulting services. (Rev 3/01)

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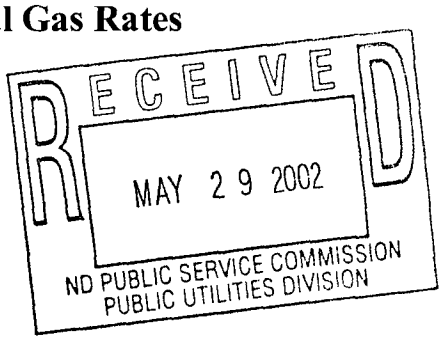
Response To Request For Proposal
To Provide Consulting Services To
The North Dakota Public Service Commission
In The Analysis Of Montana-Dakota Utility Company's
Application For Increased Retail Natural Gas Rates
In North Dakota

Case No. PU-399-02-183



Submitted To:
Mike Diller
Director Of Accounting
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480
(701) 328-4079

Submitted By:

Larkin & Associates

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MAY 29, 2002

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by Larkin & Associates
05/29/2002 CC: Comm Legal Illona, Pat. Jerry Mike

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Appendices

Appendix I – Background and Qualifications – Resumes of Larkin & Associates Professionals
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Appendix III – Background and Qualifications – Resume of Dr. John B. Legler
Appendix IV – Background and Qualifications – Resume of Scott J. Rubin

I. BUSINESS ORGANIZATION

Larkin & Associates

Larkin & Associates, PLLC is a firm of certified public accountants and regulatory consultants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Subcontractors

If the project team is selected to address issues 2 and/or 4, Dr. John Legler and Scott Rubin, each individual subcontractors to Larkin & Associates on this project, would function as the lead consultants and expert witnesses in these areas, respectively.

Larkin & Associates Firm Background

In April 1970, the certified public accounting firm of Larkin, Chapski & Co., was formed by former employees of Peat, Marwick, Mitchell & Co., a big eight accounting and auditing concern. In addition to the auditing, accounting and tax work typical of CPA firms, Larkin, Chapski & Co, specialized in the area of utility regulation. In September 1982, the firm was reorganized into Larkin & Associates, a certified public accounting and consulting firm with Hugh Larkin, Jr., as senior partner. As such, Mr. Larkin has the ultimate responsibility for all regulatory consulting work performed by the firm. Section III of this proposal provides further details on the management of our utility regulatory project team. Larkin & Associates performs a wide variety of auditing and accounting services, but concentrates in the area of utility regulation and ratemaking. The firm has performed regulatory consulting services for numerous clients.

Larkin & Associates performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 300 regulatory proceedings.

Our project team is unusually well qualified to conduct this important study for the North Dakota Public Service Commission. We believe we satisfy the key ingredients for success of this assignment: strong technical skills, utility industry experience, relevant audit experience, extensive experience with natural gas utility rate and regulatory filings, an understanding of the regulatory environment, and demonstrated project management capability.

The distinct advantages of our approach include the following:

Maximum consulting skill applied to each assignment. The effective use of consultants rests on finding the best fit between the client's needs and the skill, knowledge, and experience of the individual consultants who actually work on the assignment. Our approach maximizes the productive time of the senior consultants who work on the engagement. Furthermore, we are not encumbered by the overhead necessary to support a large firm; consequently, our clients receive more pure consulting services for every dollar they spend.

Extensive utility industry experience. Collectively, the consultants available for our assignments have extensive and diverse experience with utilities and regulation. In addition

to possessing the requisite professional skill, our project team brings together people with broad practical experience. The consultants we propose have meaningful prior experience in their field of specialization, which is the public utilities sector.

Proven technical skills. Consulting is a skill-based professional service. Our project team is made up of seasoned, career consultants who have climbed well up the experience curve at each functional discipline. The methodologies we employ have been tested successfully on many engagements. We believe our approach provides the greatest probability of producing both useful and measurable benefits.

Value added approach. Our consulting philosophy emphasizes a collaborative approach. We strive to establish the closest possible working relationship with our client's personnel. We believe that the success of consulting engagements varies directly with the degree of client involvement. Therefore, we encourage our clients to become actively involved in our assignments.

Demonstrated project management capability. We consider project management to be an essential responsibility. We have substantial experience managing a full spectrum of consulting engagements, including many complex, large-scale projects. Senior consultants are responsible for providing direction to the project team, insuring that there is sufficient depth, detail, and balance to work plans. We use the detailed work activity plans and budgets to monitor progress and as a focal point for communications with the client.

Several CPAs on project team. Our project team includes four seasoned CPAs and three CPA candidates, each of whom has devoted his or her career to addressing the issues affecting public utilities. In our extensive public utility consulting work, which encompasses management studies and rate case assistance, we stress the quantification of recommendations. Having several experienced CPAs on our team helps to insure that all of our recommendations are quantified, where possible, and that the underlying facts have been thoroughly verified.

Experience as expert witnesses. Project team members have presented testimony and have been cross-examined on numerous issues in regulatory proceedings. As a result of this experience, our team has a sharper appreciation of the value of rigorous fact verification and documentation of our findings and conclusions. We approach the investigative audit process with the type of discipline that enhances our ability to support our findings in subsequent regulatory proceedings, if and as necessary.

Expertise in developing spreadsheet models. Over the past several years, we have developed significant expertise in developing spreadsheet models to develop revenue requirements and cost of service studies.

Experience with North Dakota utility regulation. Larkin & Associates has extensive experience with North Dakota utility regulation, having assisted the Staff in a variety of utility regulatory projects.

Importance of this engagement. We can offer all of the talents and experience of a large consulting firm. At the same time, we are a small growing business where every client is very important. We strive to give each client a high degree of personalized care and attention. We anticipate being able to bring to this project, a valuable blend of big firm capabilities and small firm commitment, attention, and responsiveness.

II. PROJECT SUMMARY

Approach to Scope of Work

The purpose of the contract will be to have Larkin & Associates, along with Dr. John B. Legler and Scott Rubin, provide comprehensive technical assistance to the North Dakota Public Service Commission ("PSC" or "Commission") Staff ("Staff") in analyzing the rate increase filing made by the Montana-Dakota Utility Company (MDU).

Larkin & Associates will address issue areas 1 (rate base/investment), 3 (cost of service/revenue and expense analysis), and 5 (depreciation). Dr. Legler will address issue 2 (cost of capital), and Mr. Rubin will address issue 4 (rate design). All professionals proposed for this project have worked with each other on other regulatory projects.

The ultimate objective of this project involves presenting our conclusions and recommendations, in the form of oral testimony, before the Commission. We will assess, in light of the Commission's and Staff's regulatory philosophies and goals, an appropriate revenue requirement and rate base for MDU. We will determine a revenue requirement that can be effectively and convincingly supported at the proceeding. In order to meet these objectives, we will perform a thorough review of the filings and supporting workpapers underlying the request for an increase in rates.

Throughout the project, a high degree of communication will be maintained among all members of the project team, as well as with PSC staff members assigned to the project. Communications will be facilitated by regular staff meetings, telephone conference calls, and if necessary, trips to North Dakota to meet with Staff personnel and review data.

Our findings will be presented first in the form of oral telephone discussions and monthly progress reports to PSC staff members working on the project. Upon completion of the analytical work, we will prepare and submit to the appropriate PSC staff members, drafts of testimony. Then, after discussions with, and approval by these persons, our findings will be presented to the Commission in the form of written testimony and exhibits, to be followed with oral direct testimony and cross examination at the hearings. We will respond to interrogatories related to our scope of work issued by any parties to the proceeding. We will also analyze rebuttal testimony, prepare and assist in cross-examination procedures, and prepare and present oral testimony at the hearings. In addition, we will provide PSC Staff with technical support at the hearings, and after the hearings, in preparing proposed findings of fact. In order to present a convincing and accurate case to the Commission, we will utilize to the fullest extent possible, our accumulated expertise in accounting, economics, finance, law, taxation, and utility ratemaking.

Project Team Resources

As founder and senior partner of the firm, Hugh Larkin, Jr., assumes ultimate responsibility for each regulatory engagement the firm undertakes. Mr. Larkin will be available to act as project director of the case and will also be available to provide expert testimony in the proceedings. Mr. Larkin has worked in the regulatory field for over 20 years and has testified in over 300 rate proceedings. On this particular project, Mr. Larkin's role is anticipated to be limited to high level supervision, as necessary.

The Larkin & Associates professional staff includes four CPAs with over 80 years cumulative business public accounting experience and utility related work. Our personnel our familiar with cost of service, rate base, income taxes, lead/lag studies, and accounting adjustments as well as many other issues that have been contested in ratemaking proceedings. This background enables us to analyze these areas and to draw on knowledge gained through comparable studies performed in other utility cases. Resumes of the members of Larkin & Associates who will be participating in this project are included as Appendix I, Background and Qualifications – Resumes of Larkin & Associates professionals. Summaries of Larkin & Associates' prior gas utility rate cases are included as Appendix II, Gas Case Summaries.

Dr. Legler's and Mr. Rubin's qualifications are presented in Appendices III and IV, respectively.

Functional Approach To Work Tasks

The work on this project will be divided into multiple tasks that provide a sensible, chronological series of expected activities, encompassing the required work areas within the established time constraints. The major tasks described below represent the anticipated approach to the overall scope of work. Interaction with Staff is anticipated to coincide with all tasks performed, to provide for substantial input by these persons, so as to optimize project team performance.

1. We will discuss with Staff assigned to the project, the specifics of the approach Staff wishes to follow in this case. In this meeting, we will discuss the areas that are of particular concern. A time line will be agreed upon establishing all critical project deadlines.

2. We will perform a detailed review of the Company's filing in the current case, including its testimony and supporting workpapers. This will include a thorough analysis, review, and evaluation of all pertinent evidence filed on behalf of all parties in the current case. Additionally, we will review testimony, briefs, and orders of the Commission in prior cases to determine what issues were presented by the various parties, and how they were resolved by the Commission. Furthermore, we will determine if there are any new areas of concern that are raised by making a comparison to the testimony and order in the prior case. Based on this analysis, we will advise and recommend an approach to each specific issue.

3. We will conduct discovery of MDU, sufficient to conduct a complete analysis of the Company's case. This will include preparation of a comprehensive array of written requests for information as may be necessary for a thorough analysis of the case. Our discovery files contain many standardized data requests designed to obtain the information necessary to thoroughly evaluate typical issues we have encountered in other rate cases. These standardized requests for information provide an efficient, effective starting point in developing the first set of discovery to be served upon the Company. Additionally, we develop Company-specific data requests to clarify issues, pinpoint problem areas, and obtain follow-up information, as well as address issues and quantifications unique to this Company and rate case.

4. Larkin & Associates will submit periodic progress reports in which we will update Staff of the conclusions and recommendations we have formulated based upon our review of MDU's response to discovery. Such progress reports will also advise Staff of any potential problems we foresee in meeting project deadlines.

5. We will carefully analyze and evaluate the information received in steps 1 through 4. All information gathered as well as analyses and evaluations will be performed in order to consider all possible issues, which come to our attention during the course of our review. Based upon this evaluation, we will discuss our findings with Staff to determine which items should form the basis for proposed adjustments as part of our formal testimony.

6. We will submit drafts of testimony and exhibits in advance of the filing date so that Committee Staff and Counsel assigned to the project will be able to review them. We will thoroughly review, verify, and correct the draft testimony and exhibits to meet the satisfaction of the Committee in order to have finished copies ready for filing sufficiently in advance of the filing deadline.

7. We will assist Staff counsel with the preparation of cross-examination questions. Our tested and effective format for preparing cross-examination includes, for each issue, identification of the appropriate witness; a summary of the issue (what the Company did, why it may be inappropriate, impact on rates, and discussion of relevant discovery responses), specific cross-examination questions (primarily drafted to elicit a "yes" or "no" response to keep the witness on track) and anticipated witness responses.

8. For issues 1, 3 and 5 (rate base, net operating income, and depreciation), Helmuth W. (Bill) Schultz III or Ralph Smith will present expert testimony and undergo cross-examination at the hearings. Both have previously testified before the Commission. For issue 2 (cost of capital), Dr. Legler will be the expert witness. Dr. Legler has previously presented prefiled testimony on cost of capital before the Commission in a prior MDU rate case. For issue 4 (rate design), Scott Rubin will be the expert witness. Mr. Rubin has not previously testified in North Dakota, but has presented expert testimony on rate design before a number of other state regulatory commissions. As a result of our extensive experience in presenting expert testimony before regulatory commissions, we believe that the best preparation for responding to cross-examination by others is to present well-conceived, clearly worded, and thoroughly verified pre-filed written testimony at the onset.

9. We shall assist Staff subsequent to the hearing by preparing proposed findings of fact with respect to issues relevant to our scope of work.

Substantive Approach to Analysis of Each Group of Issues Identified in the RFP

In the following subsections of our proposal, we address our substantive approach to addressing the issues encompassed within each of the five issue groups identified in the RFP.

Approach to Revenue Requirement Analysis (Issues 1, 3 and 5, Rate Base, Net Operating Income and Depreciation)

If Staff selects Larkin & Associates to perform the work on issue areas 1, 3 and 5, we believe that this combined review would produce synergies by having the same consultants and same witness address the revenue requirement issues in this rate case. We propose to review such revenue requirement issues in the following manner. Since we have not yet begun an in-depth study of the project, the following discussion consists of areas that will have to be addressed and general areas that are likely to be of concern, and our approach to them.

Revenue Requirement

We will review the Company's proposed revenue requirement, recommend adjustments, and independently develop a revenue requirement. The revenue level should be sufficient to enable the utility to recover all of its prudently incurred costs found to be includable in the adjusted test year, plus an adequate return of its capital invested in used and useful assets devoted to the provision of jurisdictional utility service. In other words, total allowed revenues should equal total operating expenses plus depreciation, and an adequate return on investment. This is, of course, inclusive of a sufficient level of income taxes to provide an opportunity to earn such return on an after-tax basis.

Test Year

Keeping in mind prior Commission orders and North Dakota law, we will review the test year used by the Company to determine its appropriateness. We will carefully analyze any adjustments proposed by the Company to the test year to ensure that there is a proper synchronization of rate base with revenue and expense levels.

Using a historical test year assumes that revenue and expense levels experienced in the past will continue in the future; this may not be the case. Unusual events, costs, and changes in operations will be evaluated for this purpose. In the event the historical test year does not facilitate the rate recognition of such items as plant being placed into service, we will maintain the test year concept of matching rate base, return, and expenses with appropriate levels of sales.

In the event that the Company has used a projected test year or a partially historic/partially projected test year, we will analyze all budgets and forecasts underlying the projected data. Such projections will be compared to historical data and all unusual increases and decreases in costs will be questioned.

Rate Base Analysis (Issue 1)

We would expect to perform the following analysis pertaining to rate base. As noted in the RFP for issue 1, the rate base determination is not nearly as critical in terms of rate impact as is establishing the appropriate cost of service. Consequently, work in this area will be limited in scope and will commence with a review of the last rate case and historical comparisons, along with a review of MDU's filing. Variations in MDU's filing from the prior case and deviations from Commission precedent will be used as guidance for where to focus the analysis. We understand that Staff does not want the consultant to perform a cash working capital calculation.

Based on the above overall approach, issues concerning the rate base determination that may be encountered include the following:

Review the Company's accounting and budget data to ensure that the per book or forecast balances included in rate base are stated appropriately. Also ensure that all major balance sheet accounts have, in some way, been accounted for through either the rate base or capital structure ratemaking components.

Review all Company adjustments to the rate base to ensure their propriety. Rate base adjustments are normally made to update items such as plant in service to a specified date, to adjust working capital and depreciation reserve to correspond with adjusted expenses, and also to include adjustments to deferred tax offsets to the rate base. All adjustments must meet the requirements of being known and measurable. Where Company adjustments are believed to be inappropriate, we will propose alternative adjustments and explain reasons for rejecting the Company adjustment in testimony.

Analyze sources of non-investor supplied capital. Determine whether all non-investor supplied capital has either been appropriately deducted from the rate base or included in the capital structure at zero cost. Balances that should appropriately be deducted from the rate base include:

1. Accumulated deferred income taxes, reflecting the fact that this represents non-investor supplied capital.

2. Customer deposits, while at the same time treating customer deposit interest as an above-the-line expense.

3. Pre-1971 Unamortized Investment Tax Credits. Deduction from rate base of these tax credits, is not prohibited by law. To the extent that such unamortized balances are still on the Company's books, they should be deducted from rate base as non-investor supplied capital.

4. Accounts Payable associated with Plant in Service (PIS), Construction Work in Progress (CWIP), and Materials and Supplies (M&S). The PIS, CWIP, and M&S balances included in the rate base for a current return that may be partially financed by accounts payable on a continuous basis throughout the year. Such payables (e.g. contractor retentions) represent vendor-supplied capital and should be offset against the PIS, CWIP, and M&S balances in the rate base.

5. Determine whether customer advances or contributions in aid of construction are present on the Company's books and propose recommendations accordingly.

6. Review balance sheets for any other types of non-investor supplied capital, which should be reflected in the determination of rate base. These would include reserves for items such as injuries and damages, property damage, self-insurance, etc.

Determine if MDU has included any CWIP in rate base. We will determine if the expected in-service date is accurate. If CWIP is not expected to be in service within a reasonable period after the test year-end, then it should not be included in the rate base.

Review and analyze all costs associated with new plant, which goes into service during the test year. Ensure that the cost savings associated with it are simultaneously and adequately reflected.

Evaluate any Plant Held for Future Use (PHFFU) in the rate base. Some Commissions have approved the inclusion of PHFFU in the rate base. We will analyze the items requested for inclusion by the Company, verify dollar amounts, and existence of a definite plan of use within a reasonable time frame for each piece of property held for future use included in rate base. This will allow us to determine whether or not each specific item merits inclusion in the rate base.

Ensure that components of the rate base are determined on a consistent basis with components of capital employed (e.g. 13 month averages, beginning and end-of-year average balances). If considered helpful to our analysis, we will reconcile the rate base with capital structure. This can be an important analytical procedure in testing the overall reasonableness of rate base.

Analyze the specifics of certain typical rate base accounts, such as prepayments and M&S, in sub-account detail, to ensure that all sub-accounts are proper for inclusion in the rate base. Items such as temporary investments, which earn their own return or non-utility items should be excluded from the rate base.

Ensure that the Company's accounting for prepayment items are proper. Investigate the interrelationship of prepaid balances with the determination of cash working capital under the lead/lag study approach to verify that no double counting is included in the rate base.

Ensure that the inclusion of deferred debits is appropriate and review deferred credits to determine if any accounts or individual sub-accounts are proper as offsets to the rate base.

Review the deferred income tax offset to the rate base in conjunction with detailed revisions of Account 190. Account 190 (accumulated deferred income tax debit) represents an increase to rate base. Therefore, it is important to ensure that each sub-account is proper for inclusion.

It appears from MDU public financial statements that the company is deferring natural gas commodity, transportation and storage costs which are greater or less than amounts presently recovered through existing rate schedules. Consequently, MDU may have an under-recovered or over-recovered balance of deferred gas costs, which may impact the derivation of rate base. If deferred gas costs are proposed to be included in rate base by MDU, we will evaluate the balance for appropriateness, including an assessment of how financing charges related to the deferred gas cost balance are recovered in rates, and whether the balance during the test year may have been impacted by abnormal weather or includes costs which are not appropriate for ratemaking purposes. To the extent that MDU has over-recovered gas costs, the resulting balances appear to be recorded in other accrued liabilities. If over-recovered balances are

consistently occurring on MDU's books, this may represent a source of capital to the company that may need to be considered as a rate base deduction.

Operating Income and Expense (Issue 3)

In general, we will review operating income and expenses, including normalizing and out-of-period pro forma adjustments. The RFP identifies weather normalized sales as being a crucial element to the determination of adjusted net operating income. We will focus a significant amount of attention on evaluating MDU's weather normalized sales for the test year, as well as reviewing in detail MDU's proposed operating and maintenance expenses.

Our review of the operating income statement will include the following areas:

Revenues and Sales in the Test Year

Ensure that current revenues reflect the revenues, which should be generated based on the rates currently in effect. This will be done by verifying billing determinants to historical experience.

Analyze the Company's filing to determine if test year sales and revenues are representative of normal going-forward conditions, and propose any necessary adjustments. Particular attention will be paid to MDU's estimates of weather normalized sales. We have extensive experience using NOAA degree-day data and historical gas sales to estimate weather normalized sales for gas distribution utilities. Our review of MDU's test year sales will begin with a review of the Company's calculations, including detail of the Company's weather normalized sales. We will also review Commission precedent concerning the period used to determine "normal weather." Traditionally, in the utility industry, a 30-year period has been used to determine normal weather. However, in some jurisdictions, other periods have been used.

The historical accuracy of MDU's past forecasts will be examined, and an adjustment may be proposed if a pattern of sales under projection is established.

Operating revenues will be analyzed to ensure that the proper levels of revenue are reflected in these accounts. Adjustments to annualize sales for year-end customer levels and usage will be appropriately coordinated with weather normalization adjustments after review.

We will closely examine the impact of any large industrial or commercial customers closing operations or adding new operations in the Company's service territory.

The sales mix will be analyzed to ensure that unusual or non-recurring conditions have not temporarily caused shifts in usage between rate classes, such as residential and commercial. Any unusual shift in usage patterns can affect revenue calculations and cost allocation studies.

The components of "other revenues" will be reviewed to ensure that an appropriate level of each type has been reflected in the test year.

Determine whether appropriate projections are made for occasional gas sales revenue, and other types of miscellaneous revenue, which utilities frequently claim are difficult to accurately forecast.

Uncollectible accounts will be analyzed to ensure that the adjusted test year balance is representative of normal conditions. We will review the correlation of uncollectibles to revenues. Test year uncollectibles will be compared to historical results. Additionally, we will:

1. Examine the historical results experienced by the Company in the past in order to determine whether the proposed uncollectibles rate is reasonable, and whether it will likely reflect future occurrences.

2. Examine the method the Company used to calculate uncollectibles for reasonableness and compliance with Commission policy.

3. Verify the accuracy of all source amounts, including items such as gross write offs as well as residential and commercial revenues. The mathematical accuracy will also be checked to ensure that the amounts are correct.

4. Determine an appropriate provision for uncollectibles in conjunction with the calculation of the gross revenue conversion factor.

5. Evaluate the level of uncollectibles by computing uncollectibles-to-sales ratios, comparing to historical experience, and investigating Company collection policies and efforts.

We will review test year late payment charge revenues. This review will be coordinated with an analysis of uncollectibles.

Further review of weather on MDU's gas sales may be conducted, if deemed necessary. Such review may include the following type of analysis:

1. Evaluate weather information gathered from weather monitoring stations (airports and other weather stations) and information available from government resources.

2. Determine which weather station's data should be considered representative of the Company's service territory.

3. Compare data to historical averages (which represent "normal") to determine if the test year weather falls outside the range of what is considered normal.

4. Test year weather that falls significantly outside the normal range requires that test year revenues be adjusted as if the weather had been classified as "normal".

Review and analyze the Company's treatment of revenues received off system sales and net nonjurisdictional revenues. We will coordinate this review with our evaluation of the assignment/allocation of the related costs.

Operation and Maintenance Expenses

Maintenance expense will be examined to ensure that the test year does not include unusual or non-recurring maintenance, which should be amortized over a longer period for rate case purposes.

Gas costs and transmission costs. Gas cost is the largest single component of MDU's revenues, comprising about 80% of MDU's total revenues in 2001, according to the RFP. For most gas distribution utilities, gas costs are recovered through a separate rate. We will coordinate the pro forma amounts of gas costs with any revenue adjustments, including year-end annualizations and weather normalizations. To the extent deemed appropriate for this proceeding, we will also review the components of MDU's gas costs and related transportation. We have extensive experience reviewing utility gas purchasing activities and fuel procurement management. We will discuss with Staff the extent to which MDU's gas purchasing, transportation and storage costs should be reviewed in conjunction with this proceeding. Depending upon Staff's guidance in this area, discovery may be utilized to obtain an understanding of MDU's gas purchasing practices, including arranging for pipeline transportation, and incurrence of related costs. In other jurisdictions, we have also seen interest expressed concerning methods by which utilities can limit their exposure to upside gas price volatility as part of their gas procurement. We note from a review of MDU's financial statements that the Company has used natural gas and oil price swap agreements to manage a portion of its market risk associated with fluctuations in the price of natural gas and oil. MDU appears to have an overall energy price (and interest rate) risk management program. It is unclear from information reviewed to date to what extent the Company's energy risk management has affected its regulated utility operations, or whether the cost of such hedges is being charged or allocated to MDU's North Dakota gas utility operation. We will discuss such issues with Staff to see if there is an interest in pursuing such analysis with respect to MDU in this or other regulatory proceedings. For purposes of determining the cost of service in the MDU rate case, the analysis of gas cost is anticipated to be limited, unless we are otherwise instructed by Staff.

The review of non-gas cost operating and maintenance expenses is anticipated to comprise a significant portion of the cost of service review for issue 3.

Review labor and fringe benefit costs for reasonableness. We will review any adjustments for increased labor costs based on projected wage increases. Wage levels of current employees will be evaluated to determine if any increases are reasonable. We will also review wage and benefit analyses conducted by or prepared for the Company. We will compare management wage increases with those granted union employees as the result of arms-length bargaining.

Compare budgeted with actual wages and staffing levels for a representative historical period. Evaluate whether the Company budgets for unfilled employee positions, or if they otherwise tend to over-project budgeted wages. We will consider an adjustment for average vacancies.

Review relocation expense. Review any austerity measures, such as a temporary hiring freeze, leaving unfilled job vacancies produced by attrition, and offering voluntary early retirement. Investigate the impact upon test year employee costs of these programs. Evaluate

the amortization of any large one-time costs, such as those relating to an early retirement program.

Examine the Company's accounting for pension benefits. Ensure that book pension expense is computed in accordance with FASB 87 guidelines. Determine the basis for the utility's ratemaking claim for pension expense. Consider adjustments to pension expense, in light of prior Commission decisions on this issue.

If the Company has supplemental retirement plans for officers and directors, or an Employees' Investment Plan (i.e. 401k), ensure that the costs of these plans reflected in the test year reflects a normal, reasonable level of costs.

Evaluate the Company's proposal in regard to post retirement benefits other than pensions (PBOP). The prior decisions of the Commission provide guidance for how utilities are to account for the benefits other than pensions (PBOP's) using the accrual method prescribed by SFAS 106. Moreover, the SFAS 106 accruals remain subject to Commission review of prudence and reasonableness in rate cases. In performing an investigation of PBOP accounting, we may investigate some or all of the following:

1. Identify the Company's PBOP liability under SFAS 106. Review and evaluate any actuarial studies the Company or its actuary has conducted to estimate annual PBOP costs, including interest cost, service cost, and amortization of the transitional PBOP cost existing at the date the Company adopted FASB 106 for book accounting purposes.

2. Evaluate whether or not the Company's request in the current proceeding is in compliance with the Commission's prior decision.

3. Determine whether the Company has fully funded its plan under the most tax advantageous methods.

4. Review all steps being taken or planned by the Company to reduce its prospective employee benefit costs and PBOP liability.

5. Obtain the most recent actuarial estimates for the FASB 106 accrual. In past cases, we have noted that utilities' initial estimates of FASB 106 accruals have been high, and more current estimates reflect reduced accrual amounts.

6. Investigate whether the utility has capitalized a portion of its FASB 106 accrual cost. In past cases, we have noted instances where utilities have failed to capitalize portions of their FASB 106 accruals and have inappropriately attempted to over-charge O&M expense as a consequence of such failure.

Review the Company's accounting for legal expense to ensure that unusual or inappropriate costs are not charged to retail ratepayers. The test year should reflect a normal level of legal expense. Remove any penalties or unusual settlements from test year expenses, which should reflect normal operations. Consider deferral of large legal expenditures for litigation in

progress concerning questionable areas, e.g., lawsuits against officers and directors for alleged imprudence.

Review the impact of FASB 112 on expenses. The FASB 112 accrual is in the nature of a one-time establishment of a liability balance, with subsequent annual "incremental" adjustments. In this regard, it is similar to the compensated absence accrual established pursuant to FASB 43. It is the converse of unbilled revenue accounting, whereby many utilities credited Revenue and debited Unbilled Revenue Receivable (similar to an Account Receivable, but before the bill is issued) in adopting this aspect of accrual accounting. In each subsequent year, adjustments are made to the accounts for incremental changes in the balance of Unbilled Revenue. The Commission's prior handling of the unbilled revenue and the compensated absence accrual issues could therefore provide insight into potential arguments that could be presented concerning the FASB 112 issue. We will examine any FASB 112 accrual amounts proposed by the utility, and we will recommend appropriate ratemaking adjustments.

Review incentive compensation arrangements and special bonuses to employees and officers. Ensure that only reasonable amounts are included in the test year.

Review special "perks" available to top management, including "golden parachute" arrangements, use of Company assets for personal functions, bonus plans, supplemental pensions, incentive stock options, etc.

Review dues for membership in industry associations. Remove the lobbying and institutional advertising portion of such dues. Obtain data concerning benefits of association programs to the Company. Review other membership dues for appropriateness as test year expenses.

Analyze test year advertising and marketing expenses. Determine which programs and activities benefit ratepayers and provide a recommendation based on this determination for recovery of advertising and marketing expenses.

1. Review copies of advertisements run and bill inserts sent during the test year. Review Company categorization of advertisements.

2. Review test year advertising to ensure that no advertising disallowed in the last docket has been included in the current docket.

3. Review customer surveys the Company may have.

4. Review Commission orders in recent utility cases to ascertain treatment (allowance or disallowance) of promotional activities. Use such orders as guidance for treatment of marketing programs.

Analyze operating and maintenance accounts by primary and sub-accounts to determine whether any significant increases or decreases in these accounts have occurred. Investigate and document the reasons for any significant changes in operating and maintenance expenses.

Recommend adjustments for inappropriate increases and for unexplained, or unjustified cost increases.

Taxes Other than Income Taxes

Analyze other taxes by type to determine that the tax expense is related only to the test period under consideration.

Verify tax rates to current state statutes and tax assessments. Evaluate trends in property taxes and tax assessed valuation over a representative historical period. Use the most recent actual tax rates for all property.

Ensure that plant balances used in the calculation of property tax expense are appropriately synchronized with the plant balances reflected in rate base.
Investigate property tax refunds and ensure that they are properly treated for ratemaking purposes.

Analyze the rate used by the Company to determine whether the use of that rate is appropriate for state and municipal taxes.

Examine the tax rates for the major components of state and municipal taxes to ensure that there has been no decrease in state and municipal taxes, which should be reflected in the period being examined.

Below-the-Line Revenues and Expenses

Briefly analyze revenues and expenses in so-called "below-the-line" accounts. Examine these accounts with the intention of determining that these revenues and expenses are properly excluded from the cost of service.

Verify the embedded costs of debt and preferred stock to the financial statements and other supporting documents.

Determine whether the Company has sold any property during the test year or before, and realized a gain on such sales. Determine whether sold property was previously included in rate base to earn a return, or in depreciation expense or property taxes, i.e., included in rates. Consider whether any gain on the sale of such property should accrue to the benefit of the ratepayers.

Gain/Loss on Repurchase of Outstanding Debt

Some regulatory commissions have determined that it is appropriate to flow through the benefits of gains on repurchased debt to ratepayers. We will examine this issue to determine whether such treatment would be appropriate under the North Dakota regulatory framework.

If it is determined that any gains on reacquired debt should be amortized over a period of two or more years, then a determination must me made as to the proper ratemaking treatment of the amortized (credit) balance. The ratemaking treatment of such an amortized balance is the converse of the ratemaking treatment for unamortized debit balances, such as plant cancellation losses or deferred expenses.

Income Taxes
Review all tax computations in the rate filing.

Determine that interest expense used in the tax computation is properly synchronized with the interest computation in cost of capital.

Determine that deferred investment tax credits are being properly amortized. Review tests of ITC amortization performed by the Company and/or its independent auditor to ensure compliance with IRC 46(f). Coordinate ITC amortization with depreciation rates adopted in this case.

Review the Company's federal tax returns for prior two years with particular emphasis on Schedule M adjustments.

Review the Company's deferred income taxes, focusing on any Company proposed normalization treatment which deviates from established Commission policy and procedures.

Address the issue of amortization of non-protected excess deferred income taxes.

Investigate the impact of the alternative minimum tax (AMT) on the Company's income tax expense for ratemaking purposes. AMT is allowed to be carried forward indefinitely as a credit against federal income taxes payable in the future (other than AMT). Ensure that savings from participation in a consolidated federal income tax return are appropriately recognized in the ratemaking process.

Depreciation and Amortization Expense
For purposes of task 3, the cost of service review, we will analyze the Company's calculation of test year depreciation expenses to ensure that it reflects the use of Commission authorized depreciation and is properly coordinated with the other aspects of the revenue requirement determination, including the balance for Accumulated Depreciation being reflected in rate base.

Ensure that the depreciable assets used in calculating the depreciation expense agree with the books and records of the Company.

Ensure proper "matching" between depreciation expense reflected in adjusted net operating income and net plant amounts reflected in the rate base, paying particular attention to new additions to rate base.

Review each item being amortized as test year expense. Remove amortizations, which will be completed prior to rates set in this proceeding going into effect.

A more extensive review of MDU's depreciation rates, and possible changes to such rates since MDU's last depreciation study is not included in our proposed work for task 3, but is included in our proposed work for task 5. Details on our proposed approach to the

depreciation rates review (task 5) are presented in a subsequent section of this proposal, on page 20.

Rate Case Expenses
Review and analyze rate case expenses to be allowed for ratemaking purposes in this proceeding. Address the appropriate level of expenses as well as the appropriate amortization period, and treatment of the unamortized balance.

Administrative and General Expenses
Ascertain the reasonableness of the Company's test year claims for administrative and general expenses:

1. Examine the individual items by account and sub-account detail, to determine whether such amounts properly relate to the provision of gas service to ratepayers.

2. Examine all membership association dues and the related expenses to ascertain the benefit to ratepayers.

3. Examine all adjustments made by the Company to the test year expenses for reasonableness. Where we find that such adjustments seem unreasonable and do not reflect actual past experience, we will provide alternative amounts to be included as expenses.

4. Examine all costs associated with Company sponsored programs in order to determine whether such amounts are reasonable, and whether the benefits to ratepayers are commensurate with the cost of those programs.

Cost of Capital (Issue area 2)
The RFP indicates that MDU is proposing a return on equity of 13.25% using DCF analyses. This strikes us as being quite high. We also understand from the RFP that in the instant proceeding Staff does not anticipate presenting arguments for a lower cost of debt using an accounting approach rather than a yield-to-maturity approach. Dr. Legler's analysis will address the capital structure and cost of equity. It appears in this proceeding, as indicated in the RFP, that the most critical element of cost of capital will be the return on equity component.

Capital Structure
Dr. Legler will propose an equity ratio consistent with the riskiness of companies engaged in similar activities. Our experience has been that Commissions generally prefer to adopt actual capital structure ratios when actual capital structures are available. Dr. Legler will evaluate the Company's proposed capital structure to determine if it is reasonable and comparable to similarly situated companies. If not, Dr. Legler will make alternate recommendations regarding the appropriate capital structure.

Cost Rate for Debt Securities
Appropriate cost rates for senior securities, including debt and preferred stock, will be recommended. Typically, cost rates for debt securities are generally less controversial than

the cost of equity. However, it is possible that they could be an issue in this proceeding. A limited review will be conducted of the cost rates for debt and other securities in the capital structure. Such review is not anticipated to include presentation of an alternative accounting approach to determining the cost of debt.

Cost Rate for Common Equity

Dr. Legler will present an independent analysis of the cost rate for common equity, using the Discounted Cash Flow method.

The Discounted Cash Flow or DCF Method

The DCF method is based on the notion that the cost of equity is the rate which sets the discounted value of the future stream of cash flows (dividends and ultimately the selling price) equal to the current price of a company's common equity. In its basic form (assuming the stock is held forever), this translates into the sum of the expected dividend yield in the coming time period plus the assumed growth rate in dividends. Although Dr. Legler prefers the annual single growth rate version of this model, he recognizes that at the current time with low interest rates, this model produces quite low estimates of the cost of equity. Other witnesses attempt to pump up the estimated cost of capital by applying a quarterly version of the model with multiple growth rates. Dr. Legler is prepared to defend his approach, and provide critical comments regarding the assumptions frequently made by other witnesses. Dr. Legler would apply this model to the applicant company and groups of comparable risk gas companies. It should be noted that while the staff at Larkin & Associates is aware that the DCF method is MDU's preferred method of determining return on equity, the following alternative methods are presented in this proposal as well, to demonstrate Dr. Legler's expertise on the subject.

We do not anticipate much analysis of the cost of equity in this proceeding using methods other than the DCF method. However, if equity cost estimates are presented by MDU using other estimation methods, Dr. Legler is fully capable and has extensive experience addressing issues related to the use of other methods, including risk premium and CAPM. Dr. Legler's typical approach for these other methods is briefly summarized below.

Risk Premium Method

It is Dr. Legler's position that the risk premium varies considerably over time, and during periods of volatility, it may provide an unreliable estimate of the cost of equity. For consistency, Dr. Legler generally makes estimates of the cost of equity using the risk premium method and discusses why they should not be used as the primary estimate of the cost of equity, but rather be supportive of other estimates. Dr. Legler's risk premium methodology is based on estimates of expected rather than historical or realized risk premiums often used by other witnesses. Expected returns on equity are estimated using a DCF approach and a CAPM approach over a fairly long period of time. Yields on debt of comparable risk to the company being analyzed or risk-free Treasury bonds are subtracted from these equity estimates to arrive at risk premiums. Average risk premiums are then added to current yields on debt to arrive at estimates of the current cost of equity.

The Capital Asset Pricing Model (CAPM)
There is considerable controversy as to whether or not the CAPM is appropriate for estimating the cost of equity for regulated utilities. At the current time, the CAPM is likely to produce the highest estimates of the cost of equity. It is Dr. Legler's opinion that the rather high estimates produced by this model are largely the result of misapplications of the model. While Dr. Legler's own preference is not to use this method, it has gained regulatory support in recent years, and is often used by witnesses. Dr. Legler can provide estimates of the cost of equity using this method, if desired, correcting for deficiencies in the applications of other witnesses.

In applying the CAPM, the only variable that has an effect on the cost of equity of one company compared to another, is beta. Beta is a measure of a stock's volatility compared to the volatility of the overall market. A company which has less volatility than the market is considered to be less risky than the market and would have a lower cost of equity than the market. Dr. Legler's testimony documents the inconsistency of risk and return produced by this method.

The betas most frequently used by witnesses using this method are published by Value Line. Value Line betas are adjusted betas based on weak statistical properties and tend to raise the estimated cost of equity. These problems are pointed out in Dr. Legler's testimony.

Other issues, such as flotation cost adjustments or market pressure adjustments may also be raised by utility witnesses in their determination of the proposed cost of common equity. Dr. Legler has extensive experience and expertise in addressing such issues, as briefly summarized below.

Market Pressure and Flotation Cost Adjustments
Company witnesses often argue that the "bare bones" cost of equity estimates should be adjusted upward for market pressure and flotation costs associated with the issuance of additional common equity. Dr. Legler's basic position is that these costs only should be considered if the company under review has announced intentions of offering additional common stock through a public offering. It is also his opinion that the adjustment should be limited to externally raised equity capital, not the entire equity component.

Rate Design (Issue 4)
Scott Rubin will be the lead consultant and expert witness on rate design issues. The RFP indicates that MDU is proposing an increase to the residential monthly basic service charge from $6.50 to $11.70. In the event that the Commission does not accept this, MDU is proposing a weather normalization adjustment.

We will fully review MDU's cost of service study, proof of revenues, and proposed rate design to ensure that they are consistent with the Commission's policies and with established ratemaking principles. Initially, we will focus on the company's proposal to nearly double its customer charge or, alternatively, to propose an automatic adjustment mechanism to reflect weather normalization.

We are aware that other utility commissions have rejected weather normalization clauses and we agree that there are numerous policy reasons for objecting to such a clause. For example, weather normalization clauses tend to violate test-year matching principles by reflecting the impacts of one change without also reflecting corresponding (and potentially off-setting) changes in other areas of the utility's operations. In addition, a weather normalization clause sends a terrible message to the utility's customers: "because the weather was mild, your rates must go up." Customers understand, and rightly so, that mild weather should lead to lower utility costs, not higher ones. Finally, a weather normalization clause can also place undue reliance on statistical models that attempt to correlate gas consumption with particular weather characteristics. While such models might be useful for understanding trends in consumer behavior over an historical time period, they might not be as accurate or useful in predicting precise consumption levels in any particular year (which, of course, is what would be required to use such a model in an automatic rate adjustment mechanism).

In addition to the company's proposed weather normalization adjustment, we also will carefully evaluate its proposed dramatic increase in the customer charge. By making these proposals alternative, it appears clear that the company is not attempting to cost-justify an increase in the customer charge; rather it appears that it is simply attempting to reduce its level of risk from changes in sales levels. We will carefully evaluate whether there is a cost justification for changing the customer charge.

We also will carefully review and evaluate other aspects of MDU's proposed tariff changes and rate design, including the cost of service bases for its changes and proposals.

Our testimony and exhibits will include a revised rate design under the Company's proposed revenue requirement (to facilitate comparison with the Company's proposed rate design), and a recommended rate design under our proposed revenue requirement. It also will include a discussion of the methodology that should be followed to design rates to reflect any other changes in the revenue requirement.

Depreciation Rates (Issue 5)

The RFP indicates that MDU's last depreciation study was conducted in the early 1990s, and the Commission may be interested in having a depreciation study completed for this proceeding. Larkin & Associates proposes to address this issue in the following manner for purposes of this proceeding.

We will review MDU's last depreciation study.

We will review changes in the asset balances that have occurred since the data source period utilized in MDU's last depreciation study.

We will request and review retirement data and cost of removal/salvage data for selected plant accounts.

We will review any depreciation rate changes proposed by MDU in the instant proceeding.

We will review details of MDU's Accumulated Depreciation balance, and changes to the balance, by plant account detail (if available) since MDU's last depreciation study.

We will review information in Staff's files and in our files concerning depreciation rates used by other gas distribution utilities.

We will review the impact of changed standards and technology on MDU asset types.

We will review the impact of any pipe replacement programs that have been implemented by MDU since its last depreciation study.

Our work on depreciation rates analysis will be focused on evaluating accounts with the largest impact on depreciation expense and rates, and on accounts where significant changes have occurred since the preparation of MDU's last depreciation study. Our review of MDU's depreciation rates is anticipated to be adequate for making adjustments in the context of the current rate case. However, we are not proposing to conduct a fully detailed depreciation study for MDU from scratch.

Based on the above review, we will formulate recommendations concerning particular plant accounts where a change in MDU's existing depreciation rates appears to be necessary. To the extent any such adjustments are found to be necessary, we will calculate the estimated impacts on MDU's revenue requirements in this case. This will be done as a pro forma adjustment.

III. MANAGEMENT SUMMARY

The management structure of our proposed project team ensures that our work effort produces a work product of the highest quality, in a timely manner and within budget. A project director and project manager will both be utilized to ensure that the objectives of the project are met in an effective manner.

Hugh Larkin, Jr., CPA, founder and senior partner of Larkin & Associates, will serve as project director. As head of the project team, Mr. Larkin will be available to provide expert testimony, if necessary; however, it is anticipated that Mr. Larkin will not be one of the expert witnesses for this proceeding. Mr. Larkin's regulatory experience includes rate cases, management audits, litigation assistance, and training seminars. As project director, Mr. Larkin will assume ultimate responsibility for the completion of the project and the quality of the resulting work product. Ultimate approval of scheduling and each work phase will be done under his supervision. Communications between Mr. Larkin and the professional staff assigned to the project will be maintained on a daily basis.

Helmuth W. Schultz, CPA, is a senior regulatory analyst and the firm's audit and tax partner. Mr. Schultz is particularly well versed in the regulatory arena and has presented testimony on several occasions, including before the North Dakota Commission. Mr. Schultz will perform analytical work on this project on issues 1, 3 and 5 (rate base, net operating income and depreciation). Depending on the timing of the case and availability, Mr. Schultz may testify as the expert witness on behalf of Larkin & Associates concerning such issues.

Ralph C. Smith, CPA, is senior regulatory analyst. Mr. Smith has provided testimony in numerous rate cases and other regulatory matters, including testimony before the North Dakota Commission. He will perform analytical work on this project. Depending on the timing of the case and availability, Mr. Smith may testify as the expert witness on behalf of Larkin & Associates concerning such accounting issues.

Either Mr. Schultz or Mr. Smith will function as project manager for the overall work effort on this project. As such, one of these senior professionals will work closely with Staff members, coordinate the daily work efforts of the Larkin & Associates professional staff and subcontractors, monitor the progress of the project, and ensure that all deadlines are met.

Donna M. DeRonne, CPA, will perform analytical work on the project. Ms. DeRonne has extensive experience with gas utilities. She will perform a substantial amount of the detailed analysis, and will personally supervise and direct the work of the other Larkin & Associates' rate analysts assigned to the project. Ms. DeRonne will also have primary responsibility for developing the spreadsheet models to state all adjustments and to provide reconciliation of revenue requirements, as adjustments are modified by various parties during the proceedings. If desired by Staff, Ms. DeRonne would also be available to testify as an expert witness.

Dr. John B. Legler, PhD., will perform the analysis of cost of capital and fair rate of return on equity issues. In recent years, in cases in which Dr. Legler has presented testimony, rarely has a commission adopted a return on common equity lower than that recommended by Dr.

Legler. In fact, several commissions have adopted his recommendations, even when his testimony was on behalf of an intervenor. Dr. Legler has previously presented prefiled testimony concerning cost of capital and return on equity before the North Dakota Commission in a prior MDU proceeding.

Scott J. Rubin will address issue 4 (rate design) and will function as the expert witness for rate design issues. Mr. Rubin is an independent attorney and consultant, working exclusively on issues affecting the public utility industry. From 1983 until January 1994, he was an attorney and policy expert with the Pennsylvania Office of Consumer Advocate. From 1990 until he left the OCA, Mr. Rubin chaired the Water Committee of the National Association of State Utility Consumer Advocates. Since establishing his own practice in 1994, Mr. Rubin has served as a consultant, expert witness, or attorney in more than a dozen states, and before FERC and the FCC, in matters involving electric, gas, water, and telecommunications utilities. He also has testified before the U.S. House of Representatives Science Committee and a legislative committee in Pennsylvania. Mr. Rubin has given speeches throughout the country, published technical papers, and contributed to books on issues affecting the utility industry. He is a member of the faculty of the Annual Regulatory Studies Program at Michigan State University and he has served as a member of AWWA's Rates and Charges Subcommittee. Mr. Rubin earned his Bachelor's degree with distinction from Pennsylvania State University and his law degree with honors from the National Law Center at George Washington University. Mr. Rubin has testified as an expert witness on rate design and cost of service issues in more than a dozen rate cases in Arizona, Kentucky, and Pennsylvania. He also has provided assistance and technical support to another rate design consultant on several projects involving municipally owned utilities throughout the United States. Mr. Rubin's most recent appearance as a rate design and cost of service expert witness involved Kentucky-American Water Company, a water utility serving more than 250,000 people in the greater Lexington, Kentucky area. His recent work for the Ohio Consumers' Counsel in a Cincinnati Gas & Electric Co. rate case involved a combination of public policy and rate design work, focused on the utility's proposal to implement an automatic adjustment clause for main replacement expenditures. His work in that case also included advising the client on various rate design options, including considerations that should be used in designing the customer charge.

Robin Vial Bonini, Tina Miller, and Mark Dady are staff accountants and regulatory analysts with Larkin & Associates. Each has prepared calculations, performed analyses, and prepared schedules and exhibits on several Larkin & Associates' engagements. They will be involved in the project by performing analytical work, preparing schedules and exhibits, editing written testimony, and verifying data.

Appendix I, Background and Qualifications – Resumes of Key Project Personnel, presents the professional resumes, with references, of the Larkin & Associates professional staff identified above. Dr. Legler's resume is provided in Appendix III and Mr. Rubin's qualifications are presented in detail in Appendix IV.

Throughout this project, a high degree of communication will be maintained among all members of the project team, as well as PSC Staff. Communications will be facilitated by regular staff meetings, telephone conference calls, and written status reports.

IV. PRIOR EXPERIENCE

Larkin & Associates proposed project team is highly qualified to perform this engagement for the North Dakota Public Service Commission. Members of the Larkin & Associates project team have extensive experience providing consulting expertise in public utility regulation to regulatory agencies. Professional personnel proposed for this project have worked as consultants on numerous regulatory projects for regulatory commission staffs and intervenors.

Senior professionals at Larkin & Associates, including Mr. Schultz and Mr. Smith have presented expert written and oral testimony on behalf of the Staff on a number of occasions. Their resumes and the qualifications of other Larkin & Associates professionals available to work on this project are presented in Appendix I.

Appendix II, Gas Case Summaries, presents a listing of natural gas regulatory engagements which qualify Larkin & Associates to undertake the work discussed herein. References are provided for each engagement, and key project team members are identified.

Dr. Legler has previously filed testimony on behalf of Staff in other proceedings before the North Dakota Commission, and in numerous other regulatory proceedings before many other state commissions. Appendix III summarizes his qualifications and experience in performing such work.

Scott Rubin has prior experience with expert rate design testimony, including customer charges for water and energy utilities. He is also familiar with utility-proposed weather normalization adjustments. His qualifications are summarized in Appendix IV.

V. COST AND PRICE

In order to best match the project effort to the Commission Staff's needs and budget, we are proposing a number of price/issue coverage combinations, as detailed below:

Larkin & Associates, Issue 1 Only (Rate Base) Separately
If selected only to perform work related to issue 1, rate base, Larkin & Associates proposes a total not-to-exceed price of $16,500. This includes estimated professional fees of $15,500 and $1,000 for expenses. This does not include cost for an on-site review at MDU's offices, which if desired by Staff, we have separately priced, as described below.

Larkin & Associates, Issue 3 Only (Net Operating Income) Separately
If selected only to perform work related to issue 3, net operating income, Larkin & Associates proposes a total not-to-exceed price of $23,500. This includes estimated professional fees of $21,300 and $1,200 for expenses. This does not include cost for an on-site review at MDU's offices, which if desired by Staff, we have separately priced, as described below.

Larkin & Associates, Issues 1 and 3, Combined (Rate Base and Net Operating Income)
We believe there would be substantial synergies in having the same consultant and witness address both rate base and net operating income issues (i.e., addressing issues in areas 1 and 3). Accordingly, if selected to perform work on issues 1 and 3 (rate base and net operating income), Larkin & Associates proposes a total not-to-exceed price of $29,500. This includes estimated professional fees of $28,000 and $1,500 for expenses. This does not include cost for an on-site review at MDU's offices, which if desired by Staff, we have separately priced, as described below.

Larkin & Associates, Issue 5 (Depreciation) Separately
If selected only to perform work related to issue 5, review of depreciation rates, Larkin & Associates proposes a total not-to-exceed price of $16,500. This includes estimated professional fees of $15,500 and $1,000 for expenses. This does not include cost for an on-site review at MDU's offices, which if desired by Staff, we have separately priced, as described below.

Larkin & Associates, Issues 1, 3 and 5 Combined (Rate Base, Net Operating Income, Depreciation)
We believe there would be additional substantial synergies in having the same consultant and witness who is addressing both rate base and net operating income issues (i.e., addressing issues in areas 1 and 3) also address and present testimony on MDU depreciation rates (issue 5). Accordingly, if selected to perform the work described in our proposal for combined issues 1, 3 and 5 (rate base, net operating income, and depreciation), Larkin & Associates proposes a total not-to-exceed price of $35,000. This includes estimated professional fees of $33,000 and $2,000 for expenses. This does not include cost for an on-site review at MDU's offices, which if desired by Staff, we have separately priced, as described below.

Dr. John B. Legler, Issue 2 (Cost of Capital)
The separate issue price for the cost of capital section of this project is $8,500. This price includes $500 for travel and expenses, and is a firm, not-to-exceed price.

Scott J. Rubin, Issue 4 (Rate Design)
The separate issue price for the rate design section of this project is $9,000. This price includes $1,000 for travel and expenses, and is a firm, not-to-exceed price.

Total Project Price, All Five Issue Areas Combined
Because the members of our project team have worked together on other regulatory projects, and from past experience there may be a reasonable expectation that some issues being addressed by the project team would be settled prior to hearings, we believe there are additional opportunities for cost savings by having our proposed project team perform the work for Staff on all issue areas. If selected to perform all such work described in our proposal, our project team proposes to perform such work for a combined total not-to-exceed price of $49,500. This includes professional fees and expenses, but does not include cost for an on-site review at MDU's offices.

Estimated Additional Cost for On-Site Review at MDU Offices
In the event that an on-site review at MDU's offices is deemed necessary or desirable by Staff, our total bid would increase by $3,500. This additional amount includes professional fees plus travel expenses related to such on-site review.

VI. CONFLICT OF INTEREST DISCLAIMER

The undersigned does hereby certify there is no financial substantive interest in the utilities which are or may be parties in this proceeding. It is also certified than no business officer, partner, employee, agent, or any immediate family member has a substantive financial interest in the utilities, which are or may be parties in this proceeding. It is further certified that, should such a financial interest occur during the period of active involvement in the proceedings, the Commission will be immediately notified and shall have the right to terminate the contract.

Hugh Larkin Jr — May 29, 2002

Hugh Larkin, Jr. — Date

**This conflict of interest disclaimer is applicable to Larkin & Associates, John B. Legler, and Scott J. Rubin.

VII. COMPLIANCE WITH APPLICABLE LAWS & REGULATIONS

Larkin & Associates, along with John B. Legler and Scott J. Rubin, agree to comply with all applicable Equal Employment Opportunity laws and regulations, as well as the applicable provisions of the American Disabilities Act of 1991.

VIII. AUTHORIZED NEGOTIATORS

Hugh Larkin, Jr. and Ralph C. Smith are authorized to negotiate any contract on behalf of Larkin & Associate and the subcontractors for our proposal to perform the work on this project.

Hugh Larkin, Jr., CPA,
Senior Partner
Ralph C. Smith, CPA,
Senior Regulatory Consultant
Larkin & Associates PLLC
15728 Farmington Road
Livonia, MI 48154
(734) 522-3420

With Dr. Legler's and Mr. Rubin's concurrence, Larkin & Associates agrees to negotiate on behalf of the entire project team in order to simplify such negotiations from the PSC's perspective.

APPENDIX I

BACKGROUND & QUALIFICATIONS - RESUMES OF KEY PROJECT PERSONNEL

The personnel Larkin & Associates proposes for this project are ideally suited to the project's requirements. The project team includes professionals with educational backgrounds in accounting, finance, economics, business management, taxation, law and computers as well as expertise in addressing regulatory issues for electric, gas, telecommunications, water and sewer utilities.

Members of this team have extensive experience providing consulting to regulatory agencies concerning a wide range of issues affecting public utilities. The professionals proposed for this project have worked as consultants on numerous projects for regulatory commission staffs and intervenors, and have provided litigation assistance on behalf of law firms representing utilities and others. Our team includes expert consultants and CPAs who are thoroughly familiar with the issues in utility regulatory consulting engagements.

Concise resumes emphasizing gas utility experience for the professionals proposed for this project follow:

Page

HUGH LARKIN, JR. 1
HELMUTH W. SCHULTZ, III 6
RALPH C. SMITH 10
DONNA M. DeRONNE 14
TINA THILL 20
ROBIN VIAL BONINI 23
MARK S. DADY 25

HUGH LARKIN, JR.

Mr. Larkin is a certified public accountant, founder and senior partner of Larkin & Associates. He is thoroughly versed in independent auditing, as well as the design and review of accounting systems and the presentation of data for management and financial reporting. Mr. Larkin is licensed in the states of Michigan and Florida.

For 29 years, Mr. Larkin has concentrated in the field of public utility regulation. He has served as project leader for numerous financial and compliance audits and regulatory consulting engagements, and has testified as an expert witness on issues dealing with public utility management and regulation in over 300 proceedings. His testimony has been sponsored by public utility/service commission staffs, state attorneys general, groups of municipalities, a district attorney, people's counsel, public counsel, and other such entities. Jurisdictions in which Mr. Larkin has presented expert testimony include: Alabama, Alaska, Arizona, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kentucky, Kansas, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Vermont, Utah, Washington, Wisconsin, West Virginia, FERC and Canada.

Relevant Regulatory Experience

Project Manager in the review of Connecticut Natural Gas Company's proposed performance based ratemaking plan. Our testimony addressed numerous deficiencies with the Company's proposed plan. Other issues addressed in testimony included: the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

Key project team member in the review of Southern Connecticut Gas Company's proposed performance based ratemaking plan. Larkin & Associates' testimony pointed out numerous problems with the Company's proposed plan as well a discussion of the following issues: the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

Key project team member in the review of Connecticut Natural Gas Corporation's rate case filing. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Ultimately, the Company's rates were reduced. Issues addressed in testimony included: injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense.

- Mr. Larkin was a key participant in the review of Black Mountain Gas Division of Northern States Power Company, Page Operation's rate increase request. Larkin & Associates was retained by the Residential Utility Consumer Office of Arizona to submit testimony regarding Black Mountain Gas Division of Northern States Power Company, Page Operation's request for rate increase. Testimony addressed the following issues: revenue annualizations, weather normalization, late payment revenues, employee benefits, corporate overhead allocation, insurance expense, directors' fees, advertising expense, property tax expense, rate case expense and income tax rates. This was the first rate case subsequent to the purchase of Black Mountain Gas by Northern States Power Company. Consequently, corporate allocations were of particular concern in this case.

  Project team member in the review of Connecticut Natural Gas Company's proposed performance based ratemaking plan. Our testimony addressed numerous deficiencies with the Company's proposed plan. Other issues addressed in testimony included: the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

  Project Director in the review of the rate increase request of the Connecticut Natural Gas Corporation. Issues addressed in Mr. Larkin's testimony included: plant additions, accumulated depreciation, air conditioning rebate program, working capital - cost of gas, working capital - O&M, deferred credits, hardship arrearage forgiveness program, residential late payment charge revenues, sale of automatic meter reading assets, production and distribution, rent expense, payroll, employee benefits, matching gift program, personal use of Company automobile, directors' and officers' liability insurance, outside services, rate case expense, economic development expense, uncollectibles, lobbying expense, membership dues, miscellaneous expenses, general inflation adjustment, depreciation expense, property taxes, income tax expense, and interest synchronization.

  Project Director in the review of the application for an increase in rates and charges filed by the Mountain Fuel Supply Company. Testimony addressed the Company-proclaimed impact on its working gas inventory and labor requirements resulting from FERC Order 636. Another issue of paramount importance was unbilled revenue. Other issues included: cash working capital, accumulated deferred income taxes, "banked" vacation, equal payment plan, payroll expense, overtime expense, stock purchase plan expense, O&M expense percentage, payroll taxes, executive incentive retirement plan, supplemental executive retirement plan, postretirement benefits other than pensions, and consolidated income taxes.

  Project Director in the review of the request of the Indiana Gas Company to increase its rates. Issues addressed in Mr. Larkin's testimony included: weather normalized gas sales, appropriate ratemaking treatment of an acquisition adjustment, inter-company allocations, collection charge revenues and changes in customer levels.

Project Director in the review of the rate increase requested by Connecticut Natural Gas Corporation. Issues addressed in testimony by Larkin & Associates included: natural gas vehicles, software additions, working capital, accounts payable, materials and supplies, deferred credits, deferred conservation expense, economic development, sales, late payment revenue, payroll, executive compensation, incentive compensation, pensions, employee benefits, uncollectibles, hardship arrearage forgiveness program, hardship shortfalls, corporate insurance, D&O insurance, environmental liability insurance, injuries and damages, production and distribution expense, computer costs, legal expense, training costs, demonstration and selling, promotional advertising, market development, service contracts, dues, inflation and taxes.

Project Director in the review of Southern Union Gas Company's request for an increase in rates. Issues included: acquisition adjustment amortization, investment tax credit amortization, liability insurance expense, and acquisition investigation costs.

Project Director in the audit and review of United Cities Gas Company's rate increase request. Policy issues addressed in Mr. Larkin's testimony included: ratemaking treatment of acquisition adjustment, non-compete agreement, pipeline safety deferrals, gas costs, employee benefits and distribution expense.

Project team member in the review of a rate increase request by Hope Gas, Inc. The case was settled prior to hearings. Issues specifically addressed by Larkin & Associates included: post-test year plant additions, consolidated tax savings, revenues, labor costs, FAS 106, benefits, Employee Appliance Purchase Plan, corporate charges, affiliated charges, advertising and injuries and damages expense.

Project Director in the review of accounting and revenue requirement issues of the Southwest Gas Corporation. Specific issues included: prepayments, pipe replacement program, marketing and advertising expense, revenues, gain on disposition of property and officers' compensation.

Project Director in the review of Southwest Gas Corporation's Purchased Gas Adjustment Report. The following topics were addressed: lost and unaccounted for gas, adjustment to account 191 for tier-2 gas cost corrections, Santa Fe margin on system gas sales to be credited to ratepayers, allocation to Arizona of Santa Fe's profits on end-user sales.

Project Director in the review of Mountaineer Gas Company's request for an increase in rates. Issues included: plant in service, accumulated depreciation, sale of liquid propane gas plant, plant acquisition from Columbia, materials and supplies inventory, prepayments, working cash allowance, customer deposits, accrued vacation pay, rate refunds, unclaimed accounts, weather normalization, commercial and industrial sales growth, miscellaneous revenue, O&M expense, payroll expense, pension expense, uncollectibles, rate year expense, expense for mandatory drug/alcohol testing, legal and outside services expense, affiliated transactions, rate case expense, truck lease expense, inflation adjustment, EDP lease expense, advertising expense, software expense, taxes other than income, payroll taxes and income taxes.

Project Director in the evaluation of the impact of the Tax Reform Act of 1986 on the gas distribution utility operations of the Northern States Power Company. Issues included: reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC and timing of TRA associated impacts upon utility rates.

Project Director in the analysis of the Connecticut Natural Gas Corporation to determine the appropriate regulatory treatment associated with various changes in the tax code caused by tax reform and determine the impacts of the Tax Reform Act on the cost of service and revenue requirements. Other areas examined were: unbilled revenues, allowance for bad debt, inventory storage costs, cash flow changes associated with the TRA, excess accumulated deferred income tax reserve and adjustments to CNG's calculations.

Project Director in the review of Southwest Gas Corporation's Audit of Gas Procurement Practices and Purchased Gas Costs. The following topics were addressed: summary of audit conclusions and recommendations, propriety of deferred gas account, accrual of PGA reports, take-or-pay, two-tiered gas costs, non-traditional gas purchases from affiliate, ratemaking implications of SWG/Santa Fe/NGC relationship and acronyms and definitions.

Project Director hired to research and describe in detail the historical development of natural gas transportation issues at Federal and State jurisdictional levels in the case of Reynolds Metals Company vs. The Columbia Gas System, Inc. In addition, the calculation of damages and present alternative damage calculations.

A complete list of cases in which Mr. Larkin has participated/testified will be provided upon request.

Previous Positions

Employed by the international certified public accounting firm Peat, Marwick, Mitchell and Company from 1963 through 1969. Supervised major audits of the Detroit office.
Partner in the public accounting firm of Tischler & Lipson, 1969-1970.
Formed the certified public accounting firm of Larkin, Chapski and Company in 1970 (reorganized in 1982 as Larkin & Associates).

Education

Bachelor of Science, Accounting, Michigan State University, East Lansing, Michigan, 1960.
Certified Public Accountant, 1966.
Continuing professional education necessary to maintain CPA license.

Professional Affiliations

Michigan Association of Certified Public Accountants.
American Institute of Certified Public Accountants.

References

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(850) 488-9330

Eugene Koss
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Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051
(860) 827-2900

George Fleming, Esq.
Mississippi Public Service Commission
Walter Sillers State Office Building
P.O. Box 1174
Jackson, Mississippi 39215-1174
(604) 961-5400

HELMUTH W. SCHULTZ, III

Helmuth ("Bill") Schultz, a certified public accountant and management consultant, was employed with Larkin & Associates' predecessor firm, Larkin, Chapski & Company, in 1975. He is presently a Larkin & Associates partner and, as such, is responsible for all the accounting and much of the auditing work done by the firm. Mr. Schultz has evaluated numerous issues affecting regulated public utilities including capital structure, rate base, sales, fuel and purchased power expenses, O&M expenses, taxes of all types, and management controls over operations and expenses. He has made projections in the areas of sales, required generation, capital structure, rate base, overhead, O&M expenses, taxes, and cost of debt. Mr. Schultz has testified as an expert witness in numerous regulatory proceedings.

Relevant Regulatory Experience

Project team member in the review of Southwest Gas Corporation's application to amend its rate schedules. The following issues were addressed: rate base, work management system, post-test year safety additions, completed construction not classified correction, cash working capital, corrections to prepayments, working capital offset for payments from UPI, and the relationship between Southwest Gas and Utility Partners Inc. Adjustments to operating income included: labor annualization, management incentive plan, outside contractor expense, office closures, expired amortizations, amortizations of payments from UPI, environmental amortizations, American Gas Association membership dues, officer retreat expense, directors' and officers' liability insurance, property tax expense, interest synchronization, and merger related costs.

Project team member in the review of Southern Connecticut Gas Company's rate case filing. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Issues addressed in our testimony included: conservation expenditures; working capital; payroll; incentive compensation; pensions; PBOP; early retirement plan expense; outside services; computer system maintenance expense; age change program cost savings; uncollectibles; environmental remediation amortization; property taxes; reduction of income tax reserve; and federal income taxes.

Mr. Schultz was a lead consultant in the review of Black Mountain Gas Division of Northern States Power Company, Page Operation's rate increase request. Larkin & Associates was retained by the Residential Utility Consumer Office of Arizona to submit testimony regarding Black Mountain Gas Division of Northern States Power Company, Page Operation's request for rate increase. Testimony addressed the following issues: revenue annualizations, weather normalization, late payment revenues, employee benefits, corporate overhead allocation, insurance expense, directors' fees, advertising expense, property tax expense, rate case expense and income tax rates. This was the first rate case subsequent to the purchase of Black Mountain Gas by Northern States Power Company. Consequently, corporate allocations were of particular concern in this case.

Project team member in the review of Connecticut Natural Gas Corporation's rate case filing. Our review recommended a reduction in the Company's rates as opposed to the

increase requested by the Company. Ultimately, the Company's rates were reduced. Issues addressed by Larkin & Associates in testimony included: injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense.

Lead Consultant. Assisted the Office of Consumer Counsel of the State of Connecticut in a financial review of Southern Connecticut Gas Company. The review determined that the Company was over-earning and a reduction in rates was recommended. As a result of the investigation, the Company was required to either voluntarily reduce rates or file a full rate case proceeding before the Connecticut Department of Public Utility Control. Mr. Schultz testified as an expert witness in this case. Issues addressed by us in our testimony included: plant-in-service; conservation expenditures; working capital; inflation; payroll; incentive compensation; pensions; PBOP; outside services; advertising; rent expense; leak survey costs; uncollectibles; Conservation Adjustment Mechanism; depreciation; amortization; property taxes; reduction in state income tax rate; federal income taxes; and cost savings from sale and lease back of liquidated natural gas facility.

Project Manager in the review of the rate increase request by Connecticut Natural Gas Corporation. Issues addressed included: plant additions, accumulated depreciation - plant additions, air conditioning rebate program, working capital - cost of gas, working capital - O&M, deferred credits, hardship arrearage forgiveness program, residential late payment charge revenues, sale of automatic meter reading assets, production and distribution - LNG facility, rent expense - O&A center, payroll, employee benefits, pension expense, removal of certain employee benefits, matching gift program, personal use of Company vehicles, directors' and officers' liability insurance, outside services - legal, rate case expense, economic development expense, uncollectibles, lobbying expense, membership dues, adjustment for miscellaneous expenses, general inflation adjustment, CIS/DCIS depreciation expense, property taxes, income tax expense, interest synchronization.

Lead Consultant retained to review the filing of the Minnesota Alliance for Fair Competition (MAC) against Minnegasco and to analyze the July 1993 filing by Minnegasco in response to MAC's filing. Mr. Schultz was to analyze the filings and make a determination as to whether Minnegasco's Cost Apportionment Manual provide a means of: 1) determining whether costs can be identified, 2) determining if an allocation process is reasonable such that all direct costs are allocated, the remaining common costs to be allocated are reasonable, and the allocator being used is reasonable, 3) determining if the allocation process is auditable, and 4) determining if an audit trail exists.

Key project team member in the review of the accounting and revenue requirements of Southwest Gas Corporation. Prefiled testimony addressed the following issues: prepayments, pipe replacement program, marketing and advertising expense, revenues, gain on disposal of property and officers' compensation.

Project Manager in the review of the rate increase requested by Connecticut Natural Gas Corporation. Issues addressed in testimony by Larkin & Associates included: natural gas vehicles, software additions, working capital, accounts payable, materials and supplies, deferred credits, deferred conservation expense, economic development, sales, late payment revenue, payroll, executive compensation, incentive compensation, pensions, employee benefits, uncollectibles, hardship arrearage forgiveness program, hardship shortfalls, corporate insurance, D&O insurance, environmental liability insurance, injuries and damages, production and distribution expense, computer costs, legal expense, training costs, demonstration and selling, promotional advertising, market development, service contracts, dues, inflation and taxes.

Key project team member in the review of Southwest Gas Corporation's - Purchased Gas Adjustment Report. The following topics were addressed: lost and unaccounted for gas, adjustment to account 191 for Tier-2 gas cost corrections, Santa Fe margin on System Gas sales to be credited to ratepayers, allocation to Arizona of Santa Fe's profits on end-user sales.

Project Manager. Larkin & Associates was retained by the Iowa Utilities Board to perform an audit of Peoples Natural Gas Company's direct assignment and allocation of costs to its non-regulated operations in the State of Iowa. The purpose of our audit was to assess if the Company complied with its Cost Allocation Manual and to evaluate the propriety of the allocation methods embodied within the Manual.

Project Manager in the determination of the appropriate regulatory treatment associated with various changes in the tax code caused by tax reform and determine the impact of the Tax Reform Act on the cost of service and revenue requirements. Further, examine unbilled revenue, allowance for bad debt, inventory storage costs, cash flow changes associated with the TRA, excess accumulated deferred income tax reserve and adjustments to Connecticut Natural Gas' calculations.

Key project team member in the audit of gas procurement practices and purchased gas costs of Southwest Gas Corporation. The following topics were addressed: summary of deferred gas account, accuracy of PGA reports, take-or-pay, two-tiered gas costs, non-traditional gas purchases from affiliate, ratemaking implications of SWG/Santa Fe/NGC relationship and acronyms and definitions.

Lead Consultant retained by the Delaware Valley Chapter PCAUUP to review the accounting records of Philadelphia Electric Company's gas operations with specific focus on the Gas House Heating Service Contract Program. The purpose of the review was to attempt to determine the propriety of the Company's recording of revenue and expenses for the Contract Service Program. In addition, attempted to determine whether the Contract Service Program was subsidized by ratepayers' monies and whether the price of the program was below an average variable cost.

A complete list of cases in which Mr. Schultz has participated/testified will be provided upon request.

Education

Bachelor of Science in Accounting, Ferris State College, 1975.
Certified Public Accounting Certificate, 1980.
Continuing education required to maintain CPA license.

Professional Affiliations

Michigan Association of Certified Public Accountants

References

Geoff Commons, Esq.
Vermont Department of Public Service
112 State Street
Montpelier, Vermont 05602
(802) 828-2811

Richard Sobolewski
State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Mike Diller
North Dakota Public Service Commission
12th Floor, State Capital
Bismarck, ND 58505
(701) 328-2400

RALPH C. SMITH

Mr. Smith's professional credentials include being a certified financial planner, a certified rate of return analyst, a licensed certified public accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, Ohio, Pennsylvania, South Carolina, Texas, Washington, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Relevant Regulatory Experience

Project Manager in the review of Southwest Gas Corporation before the Arizona Corporation Commission. Involvement included, but was not limited to, preparing testimony, performing data analysis and monitoring the progress of the overall project. Mr. Smith was also actively involved with the Southwest Gas Corporation's Rebuttal & PGA Audit as well as the Audit of Gas Procurement Practices and Purchased Gas Cost both before the Arizona Corporation Commission.

Project team member in the review of Southern Union Gas Company's revenue requirements. Mr. Smith filed testimony addressing issues resulting from this review. Issues included: Acquisition adjustment amortization, investment tax credit amortization, liability insurance expense and acquisition investigation costs.

Project Manager in the analysis of Equitable Gas Company's rate base, operating income and revenue requirement issues including the Company's capitalization of promotional allowances, projected plant additions, accumulated deprecation, materials and supplies, accounts payable related to CWIP, customer deposits, provision for rate refund, cash working capital (billing lag, collection lag, other taxes lag, income tax lag, interest expense lag) residential sales, take-or-pay liability amortization, uncollectibles, advertising and promotional expense, recoveries of theft gas, associated dues, employee retirements, projection of work force, pension expense, marketing study, energy assistance program, depreciation, gross receipts tax, customer deposits interest and income tax expense.

Project Manager in the evaluation of Southwest Gas Corporation. Reviewed gas procurement practices and purchased gas costs. Retained by Arizona Corporation Commission to prepare a report on audit of gas procurement practices and purchased gas costs. The following topics were addressed: Summary of Audit Conclusions and

Recommendations; Propriety of Deferred Gas Account; Accuracy of PGA Reports; Take-or-pay; Two-Tiered Gas Costs; Non-Traditional Gas Purchases from affiliate; and Ratemaking implications of SWG/Santa Fe/NGC Relationship.

Project Manager in Larkin & Associates' review of Citizens Utilities Company, Arizona Gas Division's request for an increase in rates. Responsible for analyzing rate base and net operating income issues, quantifying adjustments, and writing testimony. Specific issues addressed included: Stamford Administrative Office common plant balance, cash working capital, revenue annualization, payroll expense, employee benefits expense, and investment tax credit amortization.

Project manager in the review of Missouri Gas Energy's ("MGE") affiliated transactions and Southern Union Company's corporate costs. This was the first rate case review after the acquisition by Southern Union of MGE. MGE and Southern Union's previously owned gas distribution operations (located in Texas) were approximately the same size in terms of annual revenues and rate base. This project involved a thorough review of the corporate cost allocation model that was developed after the merger occurred. Testimony addressed the following issues: common plant - Austin, Texas office; accumulated deferred income taxes; corporate allocations; New York Stock Exchange listing fees (initial and ongoing) for the new company; executive stock options and stock-based compensation; SFAS 123; incentive compensation; pensions and SFAS 106 nonpension post retirement benefits; budgeting of corporate costs and employee levels; executive offices in New York City; treatment of salary expense for geographically removed executives; affiliated transactions; KellAir, an affiliated supplier of airplane passenger service; allocation factors; use of time reporting for corporate executives.

Project team member in the evaluation of the impact of the Tax Reform Act of 1986 on the gas distribution utility operations of the Northern States Power Company. Issues included: reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC and timing of TRA associated impacts upon utility rates.

Project Manager. Larkin & Associates was employed by the Office of Consumers' Counsel of Ohio ("OCC") to review and evaluate the material filed by the River Gas Company and the East Ohio Gas Company, the PUCO Staff, and any other parties to the proceedings, relating to FAS 106 and FAS 112. Review included, but was not limited to, Company testimony and standard filing requirements, responses to discovery, Company workpapers, the Staff Report, Staff workpapers, actuarial studies supporting the accrual of postretirement benefits and the comments and findings in prior cases. This case was settled.

Project manager in the review of the rate increase requested by CNG Transmission Corporation. Issues addressed in testimony included: ratemaking treatment of extraordinary gas loss at CNG Transmission Corporation; treatment of costs incurred by CNGT associated with the Company's violations of environmental laws, and; the amortization period to be applied to CNGT's FAS 106 regulatory asset.

Project manager. Larkin & Associates was hired by the Pennsylvania OCA to review Columbia Gas Company's request to increase its rates. Mr. Smith prepared discovery, reviewed responses, reviewed documents and interviewed Company employees on-site at their Columbus, Ohio office, quantified adjustments for a wide range of issues, and prepared a report containing the impacts of our adjustments. Larkin & Associates also quantified various alternatives as part of the "collaborative" negotiating process that resulted in the final agreement concerning the amount of rate increase.

Project Manager in the analysis of Pacific Gas & Electric Company. Issued addressed included: Review revenues, sales and customer forecast, O&M expense, labor and non-labor cost, income taxes, other taxes, depreciation, return and rate base items. Adjustments were proposed for rad-waste disposal expense, non-routine maintenance expense, Geyers effluent pipeline project, outage management system, integrated distribution information system, distribution expense - tree trimming, customer accounts expense, customer charge, relocation expense, long-term disability expense (FAS 112), Performance Incentive Plan, total compensation, hazardous substance tax expense, nuclear decommissioning expense, depreciation on hydraulic production plant, and 215/245 Market Street headquarters building seismic retrofit project costs.

A complete list of cases in which Mr. Smith has participated/testified in will be provided upon request.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, Mr. Smith was involved in utility regulatory consulting, tax planning and research for businesses and individuals, tax return preparation and review, independent auditing, review and preparation of financial statements. Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.
Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.
Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986.
Recipient of American Jurisprudence Award for academic excellence.
Continuing education required to maintain CPA license and CFP certificate.
Received CPA certificate in 1981 and certified Financial Planning certificate in 1983.
Admitted to Michigan and Federal bars in 1986.

Professional Affiliations

Michigan Association of Certified Public Accountants, Committee on Management Consulting Services.
Michigan Bar Association
American Bar Association, sections on public utility law and taxation.

References

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Residential Utility Consumers Office
2828 N. Central Avenue,
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Phoenix, Arizona 85004
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Revenue Requirements Analysis
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Janice Alward, Attorney
(602) 542-6029
Christopher Kempley,
Attorney
(602) 542-6025
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Sam DeFrawi
Navy Rate Intervention
CHESNAVFACENGCOM
Building 212, 4th Floor
901 M Street, S.E.
Washington, D.C. 20374-5018
(202) 685-0130

DONNA M. DeRONNE

As a certified public accountant with Larkin & Associates, duties include the analysis of utility rate cases, researching accounting and regulatory developments, preparing computer models and spreadsheets, and preparation of written testimony and exhibits. Ms. DeRonne has testified as an expert witness in numerous regulatory proceedings. Jurisdictions in which Ms. DeRonne has participated in the analysis of regulatory filings include: Alaska, Arizona, California, Connecticut, Florida, Guam, Hawaii, Illinois, Indiana, Kentucky, Pennsylvania, Rhode Island, Utah, Vermont, Virginia, Washington, West Virginia and Wisconsin.

Relevant Regulatory Experience

Project Manager in the review of Southwest Gas Corporation's application to amend its rate schedules. Ms. DeRonne submitted testimony which addressed the following issues: rate base, work management system, post-test year safety additions, completed construction not classified correction, cash working capital, corrections to prepayments, working capital offset for payments from UPI, and the relationship between Southwest Gas and Utility Partners Inc. Adjustments to operating income included: labor annualization, management incentive plan, outside contractor expense, office closures, expired amortizations, amortizations of payments from UPI, environmental amortizations, American Gas Association membership dues, officer retreat expense, directors' and officers' liability insurance, property tax expense, interest synchronization, and merger related costs.

Project Manager in the review of Southern Connecticut Gas Company's rate case filing. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Issues addressed in testimony included: conservation expenditures; working capital; payroll; incentive compensation; pensions; PBOP; early retirement plan expense; outside services; computer system maintenance expense; age change program cost savings; uncollectibles; environmental remediation amortization; property taxes; reduction of income tax reserve; and federal income taxes.

Project Manager in the review of Southern Connecticut Gas Company's proposed performance based ratemaking plan. Larkin & Associates' testimony pointed out numerous problems with the Company's proposed plan as well a discussion of the following issues: the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

Project team member in the review of Connecticut Natural Gas Company's proposed performance based ratemaking plan. Our testimony addressed numerous deficiencies with the Company's proposed plan. Other issues addressed in testimony included: the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and

the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

Key project team member in the review of Connecticut Natural Gas Corporation's rate case filing. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Ultimately, the Company's rates were reduced. Issues addressed in testimony included: injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense.

Ms. DeRonne was a lead consultant in the review of Black Mountain Gas Division of Northern States Power Company, Page Operation's rate increase request. Larkin & Associates was retained by the Residential Utility Consumer Office of Arizona to submit testimony regarding Black Mountain Gas Division of Northern States Power Company, Page Operation's request for rate increase. Testimony addressed the following issues: revenue annualizations, weather normalization, late payment revenues, employee benefits, corporate overhead allocation, insurance expense, directors' fees, advertising expense, property tax expense, rate case expense and income tax rates. This was the first rate case subsequent to the purchase of Black Mountain Gas by Northern States Power Company. Consequently, corporate allocations were of particular concern in this case.

Project Manager. Assisted the Office of Consumer Counsel of the State of Connecticut in a financial review of Southern Connecticut Gas Company. The review determined that the Company was over-earning and a reduction in rates was recommended. As a result of the investigation, the Company was required to either voluntarily reduce rates or file a full rate case proceeding before the Connecticut Department of Public Utility Control. Ms. DeRonne testified as an expert witness in this case. Issues addressed in testimony included: plant-in-service; conservation expenditures; working capital; inflation; payroll; incentive compensation; pensions; PBOP; outside services; advertising; rent expense; leak survey costs; uncollectibles; Conservation Adjustment Mechanism; depreciation; amortization; property taxes; reduction in state income tax rate; federal income taxes; and cost savings from sale and lease back of liquidated natural gas facility.

Key project team member in the review of Connecticut Natural Gas Company's rate filing. Assisted with the preparation of data requests, analysis of data, on-site review, and preparing testimony, schedules and exhibits. Ms. DeRonne also testified as an expert witness in this case. Issues of this case were: Natural gas vehicles, software additions, working capital - O&M, accounts payable related to gas materials and supplied, non-gas materials and supplies, deferred credits, deferred conservation expense, economic development assistance deferred debits, sales, late payment revenue, payroll, pensions, employee benefits, personal use of company vehicles, uncollectibles, hardship arrearage forgiveness program, hardship shortfall deferral, corporate insurance update, directors' and officers' liability insurance, environmental liability insurance, injuries and damages, production and distribution, computer rental, maintenance and conversion, radio

maintenance and repair, management audit expense, consultants for generic proceedings, outside services - other, non-recurring outside services expense, outside services - legal, lobbying expense, corporate training expense, demonstration and selling expense, promotional advertising, market development and engineering studies, economic development deferral amortization, service contract and charge service, servicemen licensing fees, American Gas Association Membership dues, social and service club dues, postage expense, inflation adjustment, payroll taxes, property taxes, income tax expense, and interest synchronization.

Project Manager in the review of Mountaineer Gas Company on behalf of the West Virginia Consumer Advocate Division. Ms. DeRonne and Mr. Larkin prepared written testimony and exhibits in this case, however, the case was settled prior to hearings. Issues addressed by Larkin & Associates include: Post-test year plant additions, acquisition adjustment, prepayments, working capital, consolidated tax savings, revenues, payroll, pensions, FAS 112, uncollectibles, computer expense, legal costs, advertising, customer relations and training expense.

Project Manager in the review of a rate increase request by Hope Gas, Inc. Ms. DeRonne and Mr. Larkin prepared written testimony and exhibits in the case. The case was settled prior to hearings. Issues specifically addressed include: post-test year plant additions, consolidated tax savings, revenues, labor costs, FAS 106, benefits, Employee Appliance Purchase Plan, corporate charges, affiliated charges, advertising and injuries and damages expense.

Key project team member in the review of the rate increase requested by Connecticut Natural Gas Corporation. Assisted with the preparation of data requests, analysis of data, on-site review, and preparing testimony, schedules and exhibits. Ms. DeRonne also testified as an expert witness in this case. Issues addressed in testimony by Larkin & Associates include: natural gas vehicles, software additions, working capital, accounts payable, materials and supplies, deferred credits, deferred conservation expense, economic development, sales, late payment revenue, payroll, executive compensation, incentive compensation, pensions, employee benefits, uncollectibles, hardship arrearage forgiveness program, hardship shortfalls, corporate insurance, D&O insurance, environmental liability insurance, injuries and damages, production and distribution expense, computer costs, legal expense, training costs, demonstration and selling, promotional advertising, market development, service contracts, dues, inflation and taxes.

Key project team member in the review of a rate increase request by Columbia Gas Company before the Pennsylvania Public Service Commission. Ms. DeRonne prepared discovery, reviewed responses, reviewed documents and interviewed Company employees on-site, quantified adjustments for a wide range of issues and assisted in the preparation of a report containing the impact of Larkin & Associates adjustments. The case was settled prior to the filing of testimony under a "collaborative" negotiating process.

Project Manager in providing assistance to the West Virginia Consumer Advocate Divisions in the conduct of a general investigation of Equitable Gas Company's West Virginia operations. The purpose of the investigation was to determine whether Equitable's base rates were just and reasonable. Prepared rate base, operating income and revenue requirement schedules, along with addressing accounting issues. Issues addressed in the report included: discrepancies between the Company's operating reports and the annual reports filed to the Commission, plant allocated from affiliated service company, rent from gas properties, return on service company assets, comparison of cost levels with other utilities, meter reading charges allocated from an affiliate, meter & house regulatory expense, injuries and damages, legal costs, affiliated cost savings, depreciation expense and consolidated income tax savings.

Project leader in the review of a billing dispute between the Navy Public Works Center-Guam and the Guam Power Authority. Key issues included the appropriate treatment of certain costs under the FERC USOA, as required under a contract between the two parties. Duties included the analysis of Navy and GPA records, on-site review and preparation of final recommendation report and schedules.

Key Project Member. Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review the rate increase request by Connecticut Natural Gas Corporation. Issues addressed: Rate Base; including plant additions, accumulated depreciation - plant additions, air conditioning rebate program, working capital - cost of gas, working capital - O&M, deferred credits, hardship arrearage forgiveness program. Operating Income; including IS mechanism, residential late payment charge revenues, sale of automatic meter reading assets, production and distribution - LNG facility, rent expense - O&A center, payroll, employee benefits, pension expense, removal of certain employee benefits, matching gift program, personal use of Company vehicles, directors' and officers' liability insurance, outside services - legal, rate case expense, economic development expense, uncollectibles, lobbying expense adjustment - outside services, membership dues, adjustment for miscellaneous expenses, general inflation adjustment, CIS/DCIS depreciation expense, property taxes, income tax expense, interest synchronization.

A complete list of cases in which Ms. DeRonne has participated/testified will be provided upon request.

Education

Oakland University - Rochester, MI
Bachelor of Science: Accounting, April 1991
Graduated with University Honors
GPA 3.53 of 4.0
Continuing education necessary to maintain CPA license.

Professional Associations

Michigan Association of Certified Public Accountants

References

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(860) 827-2900

Dan Gimble
Utah Committee of Consumer Services
Heber M. Wells Building
160 East 300 South, Room 408
Salt Lake City, Utah 84111
(801) 530-6798

Sam DeFrawi
Navy Rate Intervention
CHESNAVFACENGCOM
Building 212, 4th Floor
901 M Street, S.E.
Washington, D.C. 20374
(202) 685-0130

TINA THILL

Ms. Thill is a staff accountant and regulatory analyst with Larkin & Associates. As such, Ms. Thill prepares discovery requests, produces spreadsheets and models, assists with the review and analysis of regulatory filings, and performs regulatory and accounting research.

Education

Eastern Michigan University - Ypsilanti, MI.
Bachelor of Business Administration: Accounting
April 1996

Relevant Regulatory Experience

Key project team member in the Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation. Our task involved performing an extensive investigation of the combined utilities gas system, tariffs, contracts, and operation. An analysis of the combined utilities compliance with market power safeguards adopted in the Commissions Decision D.98-03-073 to ensure open and nondiscriminatory service was conducted. Ms. Thill assisted with the analysis of key issues, drafting of data requests, performed on-site reviews at the company's offices, attended numerous interviews with company personnel, reviewed over 4,000 recorded telephone calls of the Gas Scheduling and Control Departments, and assisted with drafting of the final report and exhibits.

Participated in the review of the merger application between Energy East and Connecticut Energy Corporation. Larkin & Associates evaluated the merger in regards to the effect on competition in Connecticut, whether the merger is a benefit to both consumers and shareholders, effect on regulation, any factors which compels the merger for the benefit of customers, and whether there are acceptable customer protections in place to ensure affective cost control.

Participated in the rate case filing by Connecticut Natural Gas Corporation. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Ultimately, the Company's rates were reduced. Issues addressed by us in testimony included: injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense.

Key project member in the review of Chesapeake Utilities Corporation application for Approval of a Cost Accounting Manual and a Code of Conduct. Issues addressed in testimony included: regulated vs. non-regulated costs, Non-Regulated Activities, Common Management, asymmetrical pricing, segregation of duties, sales leads, joint sales calls, confidential customer information, and fees and rebates.

Project team member in the review Ameritech Illinois, Inc.'s earnings and revenue requirement in conjunction with the five-year review of the Company's Alternative Regulation Plan in ICC Docket No. 98-0252.

Project team member in the review of Matanuska Telephone Company's application for an interim rate increase and partial rate design. Duties performed included: gaining an understanding of the Company's rate case filing package, and formulating an opinion concerning the reasonableness of the amounts included in the Company's proposal.

Project team member in the review of US West Communications, Inc.'s application for approval to transfer certain assets to its new subsidiary, US West Broadband Services, Inc. Prior to the submission of Staff's testimony, the Company withdrew its application.

Project team member in the review of US West Communications, Inc.'s application for a rate increase. Tasks performed on this project included reviewing US West's filing, issuing and reviewing discovery, reviewing background information, obtaining US West's direct and rebuttal testimony from its prior rate case, and conducting discussions with Staff and US West regarding various issues.

Project team member in the review to determine whether the proposed merger between US West Communications, Inc. (USWC), and Qwest Communications Corporation was in the interest of ratepayers. The analysis consisted of review of the application, data responses, and USWC's service quality history.

Key project member in the review of Delmarva Power & Light's billing system conversion problems. Consulting services were provided to the Hearing Examiner of the Delaware Public Service Commission. Relevant issues addresses included: compensation and economic damages to customers, proration, arbitration procedures. Non-economic issues included: "reaching back" problem, budget plans, tariff rates on bills, high bill parameters, PriceWaterhouseCoopers audit report, payment posting sequence, emergency phone number, issue list, lost customers, walk-in offices, and a summit for unresolved issues.

Key project member in the review of Delmarva Power & Light's application for Approval of a Cost Accounting Manual and a Code of Conduct. Consulting services were provided to the Hearing Examiner of the Delaware Public Service Commission.

Participated in the review of the merger application between Energy East and Connecticut Energy Corporation. Larkin & Associates evaluated the merger in regards to the effect on competition in Connecticut, whether the merger is a benefit to both consumers and shareholders, effect on regulation, any factors which compels the merger for the benefit of customers, and whether there are acceptable customer protections in place to ensure affective cost control.

Reference

Jack Fulcher
California Public Utility Commission
505 Van Ness Avenue
San Francisco, CA 94102
(415) 703-2061

ROBIN VIAL BONINI

Ms. Vial Bonini is a regulatory analyst and staff accountant with Larkin & Associates. As such, Ms. Vial Bonini assists with the review and analysis of regulatory filings, prepares computer spreadsheets and models, prepares discovery requests and performs accounting and regulatory research. She also participates in the annual audit of a railroad company.

Education

Michigan Technological University - Houghton, MI.
Bachelor of Business Administration: Public Accounting Management Concentration
November 1996 - Honors Graduate

Regulatory Experience

Project team member in the review of Southwest Gas Corporation's application to amend its rate schedules. The following issues were addressed: rate base, work management system, post-test year safety additions, completed construction not classified correction, cash working capital, corrections to prepayments, working capital offset for payments from UPI, and the relationship between Southwest Gas and Utility Partners Inc. Adjustments to operating income included: labor annualization, management incentive plan, outside contractor expense, office closures, expired amortizations, amortizations of payments from UPI, environmental amortizations, American Gas Association membership dues, officer retreat expense, directors' and officers' liability insurance, property tax expense, interest synchronization, and merger related costs.

Key project team member in the Regulatory Audit of GTE California Incorporated and its Corporate Affiliates. The project team reviewed and reported on the Company's performance under an alternative regulatory plan including affiliate transaction compliance. Analysis consisted of formal data requests, interviews with numerous Company personnel, discussions with Staff, and an extensive review of the company's financial records. The main concentration of the audit was the review of the Company Cost Allocation Manual, the Allocation process, verification of cost allocation factors and testing of cost allocations. Specific testing was performed on selected budget center allocations and the criteria used in assigning the respective budget centers allocation factor. Also a detailed analysis of affiliate contracts was performed to evaluate whether contracts did not provide an opportunity for cross subsidization. Finally controls were reviewed to determine whether sufficient structural safeguards exist to provide a reasonable level of assurance that costs are being applied appropriately.

Project team member in the review of US West Communications, Inc. application for a rate increase. Tasks performed on this project included reviewing US West's filing, issuing and reviewing discovery, reviewing background information, obtaining US West's direct and rebuttal testimony from its prior rate case, and conducting discussions with Staff and US West regarding various issues.

Project team member in the review of US West's access and toll rate reductions for North Dakota Service pursuant to ND Senate Bill No. 2420, and to review US West's residence

rate increase pursuant to ND Senate Bill No. 2420. Relevant issues analyzed included: Intrastate Loop Cost Recovery, NTS Central Office Equipment Costs, Extended Area Service Costs, Sale of US West North Dakota Exchanges, and Other Adjustments.

Key project team member in the annual financial audit of a Lake State Railway Company. Duties include: verification of cash and authority over fund receipts and disbursements.

Reference

Kevin Mitrzyk, Controller
Lake State Railway Company.
323 Newman Street
P.O. Box 232
East Tawas City, MI 48730
(517) 362-0214

MARK S. DADY

Mr. Dady is a staff accountant and regulatory analyst with Larkin & Associates. As such, he prepares discovery requests, produces spreadsheets and models, assists with the review and analysis of regulatory filings, and performs regulatory and accounting research.

Education

- Davenport University, Dearborn, MI
  Bachelor of Business Administration, Accounting
  March 2001 – Graduated with High Honors

Regulatory Experience

- Since joining the firm in November 2001, Mr. Dady has worked on a diverse range of regulatory projects under the supervision of senior members of the firm. He has prepared data requests, analyzed issues, prepared schedules, and assisted in the determination of the jurisdictional revenue requirements for a variety of regulated public utilities.

- Key project team member in the annual audit of Lake State Railway Company. Duties include: verification of cash receipts and disbursements, payroll, and inventory.

Reference
Kevin Mitrzyk, Controller
Lake State Railway Company
323 Newman Street
P.O. Box 232
East Tawas, MI 48730
(517) 362-0214

APPENDIX II
LARKIN & ASSOCIATES
GAS CASE SUMMARIES
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GAS CASES

PG&E 1999 Rate Case

Client: Department of the Navy
Director, Navy Rate Intervention
CHESNAVFACENGCOM
Building 212, 4th Floor
901 M Street, S.E.
Washington, D.C. 20374-5018
(202) 685-0130

Contact: Sam DeFrawi

Assignment: Larkin & Associates was retained by the Department of the Navy to analyze PG&E's application for a rate increase, including its testimony, exhibits and workpapers. We presented testimony on behalf of the Navy representing the Department of Defense and all other Federal Executive Agencies (Navy) to address the following issues: GRC Policy, Electric Revenues at Present Rates, Electric Generation Expenses, Gas Revenues at Present Rates, Other Operating Revenues, Total Compensation Expense, Administrative & General Expenses, Injuries and Damages (Account 925), Pensions and Benefits (Account 926), Long-term Disability/FAS Expense, Meter Reading, Payroll Taxes, Diablo Canyon Decommissioning, Humboldt Decommissioning, Fossil and GeoThermal Decommissioning, and the ORA's Results of Examination.

Key participants Ralph C. Smith
Donna DeRonne

Geographic Location: California

Contract Duration: 1999 – 2000

Connecticut Natural Gas Company; Docket No. 99-09-03, Phase II

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski
Gene Koss

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review Connecticut Natural Gas Company's proposed performance based ratemaking plan. Our testimony addressed numerous deficiencies with the Company's proposed plan as well as the following issues: the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

Key Participants: Hugh Larkin Jr.
Donna DeRonne

Geographic Location: Connecticut

Contract Duration: 2000

Southwest Gas Corporation; Docket No. G-01551A-00-0309

Client:	Arizona Corporation Commission 1200 West Washington Street Phoenix Arizona 85007 (602) 542-0745
Contact:	Janice Alward
Assignment:	Larkin & Associates was retained by the Arizona Corporation Commission to review Southwest Gas Corporation's application to amend its rate schedules. Issues addressed in testimony included rate base, work management system, post-test year safety additions, completed construction not classified correction, cash working capital, corrections to prepayments, working capital offset for payments from UPI, and the relationship between Southwest Gas and Utility Partners Inc. Adjustments to operating income included: labor annualization, management incentive plan, outside contractor expense, office closures, expired amortizations, amortizations of payments from UPI, environmental amortizations, American Gas Association membership dues, officer retreat expense, directors' and officers' liability insurance, property tax expense, interest synchronization, and merger related costs.
Key Participants:	Donna DeRonne Helmuth W. Schultz, III Robin Vial-Bonini
Geographic Location:	Arizona
Contract Duration:	2000 - 2001

Southern Connecticut Gas Company; Docket No. 99-04-18, Phase II

Client:	State of Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051-2644 (860) 827-2900
Contact:	Richard Sobolewski Gene Koss
Assignment:	Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review the rate case filing by Southern Connecticut Gas Company. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Issues addressed by us in our testimony included: conservation expenditures; working capital; payroll; incentive compensation; pensions; PBOP; early retirement plan expense; outside services; computer system maintenance expense; age change program cost savings; uncollectibles; environmental remediation amortization; property taxes; reduction of income tax reserve; and federal income taxes.
Key Participants:	Helmuth W. Schultz, III Donna DeRonne
Geographic Location:	Connecticut
Contract Duration:	1999

Questar Gas Company; Docket No. 99-057-20

Client:	Committee of Consumer Services Heber M. Wells Building 160 East 300 South, P.0. Box 146782 Salt Lake City, Utah 84114-6782 (801) 530-6674
Contact:	Dan Gimble
Assignment:	Larkin & Associates was under contract with the Committee of Consumer Services to review the application for an increase in rates and charges filed by Questar Gas Company. Our testimony addressed the following issues: Revenues, gain on sale of property, advertising expense, incentive compensation, uncollectibles, phantom stock correction, rate of return adjustment from affiliates and contingent liabilities. The revenue requirement portion of the case was settled prior to hearings.
Key Participants:	Hugh Larkin, Jr. Donna DeRonne
Geographic Location:	Salt Lake City, Utah
Contract Duration:	Early 2000

Southern Connecticut Gas Company; Docket No. 99-04-18, Phase III

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski
Gene Koss

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review Southern Connecticut Gas Company's proposed performance based ratemaking plan. Our testimony pointed out numerous problems with the Company's proposed plan. Testimony also addressed the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

Key Participants: Hugh Larkin, Jr.
Donna DeRonne

Geographic Location: Connecticut

Contract Duration: 2000

Connecticut Natural Gas Corporation; Docket No. 99-09-03, Phase I

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski
Gene Koss

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review the rate case filing by Connecticut Natural Gas Corporation. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Ultimately, the Company's rates were reduced. Issues addressed by us in testimony included: injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense.

Key Participants: Hugh Larkin, Jr.
Helmuth W. Schultz, III
Donna DeRonne
Tina Thill

Geographic Location: Connecticut

Contract Duration: 1999

Black Mountain Gas Division of Northern States Power Company, Page Operations; Docket No. G-03493A-98-0705

Client: Arizona Residential Utility Consumer Office
2828 N. Central Avenue, Suite 1200
Phoenix, Arizona 85004
(602) 279-5659

Contact: Marylee Diaz Cortez

Assignment: Larkin and Associates was retained by the Residential Utility Consumer Office to review Black Mountain Gas Division of Northern States Power Company Page, Operation's rate increase request. Testimony submitted addressed the following issues: revenue annualizations, weather normalization, late payment revenues, employee benefits, corporate overhead allocation, insurance expense, directors' fees, advertising expense, property tax expense, rate case expense and income tax rates. This was the first rate case subsequent to the purchase of Black Mountain Gas by Northern States Power Company. Consequently, corporate allocations were of particular concern in this case.

Key Participants: Hugh Larkin, Jr.
Helmuth W. Schultz, III
Donna M. DeRonne

Geographic Location: Arizona

Contract Duration: February 1999 - July 1999

Energy East Corporation and CTG Resources; Application No. 99-08-09

Client:	Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051
Contact:	Richard Sobolewski
Assignment:	Larkin & Associates were asked to review the merger of CTG Resources, Inc. and Energy East Corporation. Certain merger issues examined include: the merger's effect on competition in the State of Connecticut; the merger's consistency with public interest; whether it would benefit both consumers and stockholders; whether there were acceptable customer protections in place to ensure effective cost control; how the merger would effect regulation; and whether there were any factors benefitting customers which clearly compel the approval of the merger.
Key Participants:	Hugh Larkin, Jr. Donna DeRonne Tina Thill
Geographic Location:	Connecticut
Contract Duration:	1999-2000

EnergyEast Corporation and Connecticut Energy Corporation; Application No. 99-07-20

Client:	Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051
Contact:	Richard Sobolewski
Assignment:	The Connecticut Office of Consumer Counsel requested the assistance of Larkin & Associates in the review of the merger application between Energy East and Connecticut Energy Corporation. Larkin evaluated the merger in regards to the effect on competition in Connecticut, whether the merger is a benefit to both consumers and shareholders, effect on regulation, any factors which compels the merger for the benefit of customers, and whether there are acceptable customer protections in place to ensure affective cost control.
Key Participants:	Hugh Larkin, Jr. Donna DeRonne Tina Thill
Geographic Location:	Connecticut
Contract Duration:	1999-2000

Southern Connecticut Gas Company; Docket No. 99-04-18

Client:	Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051
Contact:	Richard Sobolewski
Assignment:	Larkin & Associates was retained by the Connecticut Office of Consumer Counsel to conduct a financial review of Southern Connecticut Gas Company. Larkin & Associates recommended adjustments to both rate base and operating income. An alternative ratemaking plan and performance based ratemaking plan were both further examined. Specific areas analyzed and addressed: truckline project; conservation expenditures; working capital; incentive pay; payroll; payroll tax expense; pensions; health care benefits and other benefits; early retirement plan expense; outside services expense; computer system maintenance expense; AGA dues expense; age change program cost savings; additional cost savings; amortization of environmental remediation costs; amortization of three-way payment forgiveness plan; uncollectibles; lease income; property tax expense; reduction of income tax reserve; income tax expense; and interest synchronization.
Key Participants:	Helmuth W. Schultz, III Donna M. DeRonne Tina Thill
Geographic Location:	Connecticut
Contract Duration:	1999-2000

Southern Connecticut Gas Company; Docket No. 97-12-21

Client:	State of Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051-2644 (860) 827-2900
Contact:	Richard Sobolewski Gene Koss
Assignment:	Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to conduct a financial review of Southern Connecticut Gas Company. Our review determined that the Company was over-earning and a reduction in rates was recommended. As a result of the investigation, the Company was required to either voluntarily reduce rates or file a full rate case proceeding before the Connecticut Department of Public Utility Control. Issues addressed by us in our testimony included: plant-in-service; conservation expenditures; working capital; inflation; payroll; incentive compensation; pensions; PBOP; outside services; advertising; rent expense; leak survey costs; uncollectibles; Conservation Adjustment Mechanism; depreciation; amortization; property taxes; reduction in state income tax rate; federal income taxes; and cost savings from sale and lease back of liquidated natural gas facility.
Key Participants:	Helmuth W. Schultz, III Donna DeRonne
Geographic Location:	Connecticut
Contract Duration:	1998

Pacific Gas & Electric Company; Docket No. 97-12-020

Client: Department of the Navy
Director, Navy Rate Intervention
CHESNAVFACENGCOM
Building 212, 4th Floor
901 M Street, S.E.
Washington, D.C. 20374-5018
(202) 685-0130

Contact: Sam DeFrawi
Donald Coates

Assignment: Larkin & Associates was retained by the Department of the Navy and all other Federal Executive Agencies to perform utility revenue requirement studies of Pacific Gas & Electric Company in connection with the company's 1999 general rate case. Our testimony addressed a number of issues affecting PG&E's jurisdictional revenue requirements for its gas and electric operations, including the following: revenue, total compensation, other post-employment benefits accrual amortization (FAS 112), pension expense, employee transition expense for hydro facilities, nuclear decommissioning expense, fossil and geothermal decommissioning expense, injuries and damages, and administrative and general expense.

Key Participant: Ralph C. Smith

Geographic Location: California

Contract Duration: 1998

Citizens Utility Company, Northern Arizona Gas Division; Docket No. E-1032-95-473

Client:	Arizona Corporation Commission Utilities Division 1200 W. Washington Phoenix, Arizona 85007 (602) 542-0745
Contact:	Janice Alward Chris Kempley
Assignment:	Larkin & Associates' reviewed Citizens Utilities Company, Northern Arizona Gas Division's request for an increase in rates. We were responsible for analyzing rate base and net operating income issues, quantifying adjustments, and writing testimony. Specific issues addressed included: construction work in progress; AR-13 amounts; Stamford Administrative Office common plant balance; accumulated deferred income taxes; acquisition adjustment; cash working capital; payroll expense; incentive compensation; FAS 106 expense; property taxes; legal, regulatory, and special studies expense; Target: Excellence expense; injuries and damages expense; insurance expense; Stamford Administrative Office expense; Phoenix Administrative Office expense; gas sales promotional expense; A&G expense disallowance; income tax rates. We also addressed the ratemaking treatment of the Company's build-out program. Furthermore, we coordinated with ACC Staff in addressing purchased gas costs. This case was settled.
Key Participants:	Ralph C. Smith
Geographic Location:	Phoenix, Arizona
Contract Duration:	December 1995 - October 1996

Columbia Gas of Pennsylvania (Collaborative)

Client:	Pennsylvania Office of Consumer Advocate 555 Walnut Street Forum Place, 5th Floor Harrisburg, PA 17101-1923 (717) 783-5048
Contact:	Tad Berger
Assignment:	Larkin & Associates was hired by the Pennsylvania Office of Consumer Advocate to review Columbia Gas Company's request to increase its rates. We prepared discovery, reviewed responses, reviewed documents and interviewed Company employees on-site at their Columbus, Ohio office, quantified adjustments for a wide range of issues, and prepared a report containing the impacts of our adjustments. We also quantified various alternatives as part of the "collaborative" negotiating process that resulted in the final agreement concerning the amount of rate increase.
Key Participants:	Ralph C. Smith Donna DeRonne
Geographic Location:	Pennsylvania
Contract Duration:	1995 - 1996

Missouri Gas Energy; Case No. GR-96-285

Client:	Missouri Public Service Commission Staff P.O. Box 360 Jefferson City, Missouri 65102
Contact:	Chuck Hyneman, Case Coordinator, (816) 889-3551 Roy Boltz, Lead Auditor, (573) 751-4890 John Himmelberg, Jr., Assistant General Counsel, (573) 751-7485
Assignment:	Larkin & Associates was retained by the Missouri Public Service Commission Staff to review Missouri Gas Energy's ("MGE") affiliated transactions and Southern Union Company's corporate costs. This was the first rate case review after the acquisition by Southern Union of MGE. MGE and Southern Union's previously owned gas distribution operations (located in Texas) were approximately the same size in terms of annual revenues and rate base. This project involved a thorough review of the corporate cost allocation model that was developed after the merger occurred. Testimony addressed the following issues: common plant - Austin, Texas office; accumulated deferred income taxes; corporate allocations; New York Stock Exchange listing fees (initial and ongoing) for the new company; executive stock options and stock-based compensation; SFAS 123; incentive compensation; pensions and SFAS 106 nonpension post retirement benefits; budgeting of corporate costs and employee levels; executive offices in New York City; treatment of salary expense for geographically removed executives; affiliated transactions; KellAir, an affiliated supplier of airplane passenger service; allocation factors; use of time reporting for corporate executives.
Key Participants:	Ralph C. Smith
Geographic Location:	Missouri
Contract Duration:	1996

Equitable Gas Company; Case No. 96-0059-G-GI

Client: Consumer Advocate Division
West Virginia Public Service Commission
7th Floor, Union Building
723 Kanawha Boulevard, East
Charleston, West Virginia 25301
(304) 558-0526

Contact: Billy Jack Gregg
Byron Harris

Assignment: Larkin & Associates was retained by the Consumer Advocate Division of the State of West Virginia to assist in the conduct of a general investigation of Equitable Gas Company's ("Equitable") West Virginia operations. The overall purpose of the investigation, which was initiated by the Consumer Advocate Division, was to determine whether Equitable's base rates, which were set over five years prior, were just and reasonable. Since there was not a rate case filed by the Company, we were responsible for preparing the rate base, operating income and revenue requirement schedules, along with addressing all accounting issues. Issues addressed in our final report include: discrepancies between the Company's operating reports and the annual reports filed to the West Virginia Public Service Commission; plant allocated from an affiliated service company; rent from gas properties; return on service company assets; comparison of cost levels with other West Virginia utilities; meter reading charges allocated from an affiliate; meter & house regulator expense; injuries and damages; legal costs; affiliated cost savings; depreciation expense; and consolidated income tax savings.

Key Participant: Donna DeRonne

Geographic Location: Pittsburgh, Pennsylvania; West Virginia

Contract Duration: May 1996 - November 1996

Peoples Natural Gas Company; Docket No. INU-94-2

Client:	Iowa Utilities Board Lucas State Office Building Des Moines, Iowa 50319 (515) 281-5541
Contact:	Don Judisch
Assignment:	Larkin & Associates was retained by the Iowa Utilities Board to perform an audit of Peoples Natural Gas Company's direct assignment and allocation of costs to its non-regulated operations in the State of Iowa. The purpose of our audit was to assess if the Company complied with its 1995 Cost Allocation Manual and to evaluate the propriety of the allocation methods embodied within the Manual.
Key Participants:	Helmuth W. Schultz, III
Geographic Location:	Omaha, Nebraska
Contract Duration:	July 1996 - December 1996

Connecticut Natural Gas Corporation; Docket No. 95-02-07

Client:	State of Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051-2644
Contact:	Richard Sobolewski Eugene Koss
Assignment:	Larkin & Associates was retained by the Office of Consumer Advocate of the State of Connecticut to review the rate increase requested by Connecticut Natural Gas Corporation. Issues addressed in testimony by Larkin & Associates include: natural gas vehicles, software additions, working capital, accounts payable, materials and supplies, deferred credits, deferred conservation expense, economic development, sales, late payment revenue, payroll, executive compensation, incentive compensation, pensions, employee benefits, uncollectibles, hardship arrearage forgiveness program, hardship shortfalls, corporate insurance, D&O insurance, environmental liability insurance, injuries and damages, production and distribution expense, computer costs, legal expense, training costs, demonstration and selling, promotional advertising, market development, service contracts, dues, inflation and taxes.
Key Participants:	Hugh Larkin, Jr. Helmuth W. Schultz, III Donna DeRonne
Geographic Location:	Connecticut
Contract Duration:	1995

Mountaineer Gas Company; Case No. 95-0011-G-42T

Client:	Consumer Advocate Division West Virginia Public Service Commission 7th Floor, Union Building 723 Kanawha Boulevard, East Charleston, West Virginia 25301 (304) 558-0526
Contact:	Billy Jack Gregg Byron Harris
Assignment:	Larkin & Associates was retained by the Consumer Advocate Division of the State of West Virginia to review the rate increase request by Mountaineer Gas Company in regards to revenue requirement issues. Rate base items addressed include: Post test year plant additions, acquisition adjustment, prepayments and working capital. Operating income areas addressed include: consolidated tax savings, revenues, payroll, pensions, FAS 112, uncollectibles, computer expense, legal costs, advertising, customer relations expense, and training expense.
Key Participants:	Hugh Larkin, Jr. Donna DeRonne
Geographic Location:	Charleston, West Virginia
Contract Duration:	February 1995 - June 1995

Hope Gas, Inc.; Case No. 95-0003-G-42T

Client:	Consumer Advocate Division West Virginia Public Service Commission 7th Floor, Union Building 723 Kanawha Boulevard, East Charleston, West Virginia 25301 (304) 558-0526
Contact:	Billy Jack Gregg Byron Harris
Assignment:	Larkin & Associates was retained by the Consumer Advocate Division of the State of West Virginia to review the rate increase request by Hope Gas, Inc., specifically as it relates to revenue requirement issues. Examples of items specifically addressed in testimony include: post test year plant additions, consolidated tax savings, revenues, labor expense, FAS 106, benefits, Employee Appliance Purchase Plan, corporate charges, affiliated charges, advertising and injuries and damages expenses.
Key Participants:	Hugh Larkin, Jr. Donna DeRonne
Geographic Location:	Charleston, West Virginia
Contract Duration:	February - June, 1995

UGI Utilities, Inc. - Gas Division; Docket No. R-953297

Client:	Pennsylvania Office of Consumer Advocate 555 Walnut Street Forum Place, 5th Floor Harrisburg, PA 17101-1923 (717) 783-5048
Contact:	Mark Shostak Diana Dusman
Assignment:	Larkin & Associates was employed by the Pennsylvania Office of Consumer Advocate ("OCA") to review gas distribution utility's filing for rate increase and compute adjusted revenue requirement, rate base and net operating income. Testimony addressed adjustments to rate base for cash working capital and adjustments to net operating income for the following: Revenue from Customer in Chapter 11 Bankruptcy; Rate IS/IL sales; Gasmark (an affiliated gas marketing entity) net revenues; Group Hospital Expense; Reading is Fundamental; Promotional Allowances/Demand Side Management; Heating Efficiency Program; High Efficiency Water Heating Program; Air Conditioning Program; Natural Gas Powered Vehicle Program; Industry Organization Dues/Company Memberships; Rate Case Expense; Employee Perks; FAS 106 Expense; FAS 112 Expense; Outside Services - Legal; Outside Services - Other; Outside Service Other - Management Audit; United Valley Insurance Company; Repairs to Gas Preparation Equipment; Payroll; Annual Bonus Plan; Injuries and Damages; Provision for Large Claims Paid; Small Claims; Insurance Expense; Economic Depreciation; Reading Service Building Renovations; Non-Qualified Executive Retirement Plan; Directors' Pension; Holding Company - Holiday Parties & Misc. Employee Activities; Holding Company - Depreciation/Amortization Credit; Holding Company - Membership Dues; Holding Company - Employee Business Expense; Holding Company - United Way Expenses; Relocation Expense; Employee Hiring Expense; Account 908 - Customer Assistance Expense; Customer Service Information Expenses Amortization; Storm Damage; Low Income Self Help Program; Uncollectibles; Payroll Taxes; PUC assessment; Interest Synchronization; and Competitive Adjustment.
Key Participants:	Ralph C. Smith
Geographic Location:	Harrisburg, PA
Contract Duration:	1995

East Ohio Gas Company and The River Gas Company; Docket No. 93-2006-GA-AIR

Client:	Office of Consumers' Counsel Planning, Policy and Research 77 South High Street, 15th Floor Columbus, Ohio 43266-0550 (614) 466-8574
Contact:	Kenneth Rosselet, Jr. Maria Byrd
Assignment:	Larkin & Associates was employed by the Office of Consumers' Counsel of Ohio ("OCC") to review and evaluate the material filed by the River Gas Company and the East Ohio Gas Company, the PUCO Staff, and any other parties to the proceedings, relating to FAS 106 (post employment benefits other than pensions) and FAS 112 (employer's accounting for post employment benefits.) Review included, but was not limited to, Company testimony and standard filing requirements, responses to discovery, Company workpapers, the Staff Report, Staff workpapers, actuarial studies supporting the accrual of postretirement benefits, the joint comments and reply comments filed by the Customer Coalition in Case No. 92-1751-AU-COI, the entries, Findings and Orders, Applications, Comments and Reply Comments filed under Case Nos. 92-1751-AI-COI, 93-398-GA-AAM and 93-397-GA-AAM. This case was settled.
Key Participants:	Ralph C. Smith
Geographic Location:	Columbus, Ohio
Contract Duration:	1994-1995

CNG Transmission Corporation; Docket No. RP94-96

Client:	State of Pennsylvania 555 Walnut Street Forum Place, 5th Floor Harrisburg, PA 17101-1923 (717) 783-5048
Contact:	Linda Smith
Assignment:	Larkin & Associates was employed by the Pennsylvania Office of Consumer Advocate ("OCA") to review the rate increase requested by CNG Transmission Corporation. The following services were provided to the Pennsylvania Consumer Advocate: Analysis of the Company's filing, preparation of interrogatories and participation in other discovery activities; Preparation of responses to interrogatories propounded upon the OCA by other parties; Analysis of the Company's direct and rebuttal testimony, assistance in preparing cross-examination and attendance during such cross-examination. Preparation of direct testimony and rebuttal testimony and submit to cross-examination thereon. Technical assistance in the preparation of briefs. Issues addressed in testimony included: ratemaking treatment of extraordinary gas loss at CNG Transmission Corporation; treatment of costs incurred by CNGT associated with the Company's violations of environmental laws, and; the amortization period to be applied to CNGT's FAS 106 regulatory asset.
Key Participants:	Ralph C. Smith
Geographic Location:	Harrisburg, Pennsylvania
Contract Duration:	1994-1995

Indiana Gas Company; Cause No. 39353, Phase II

Client:	Office of Utility Consumer Counselor Indiana Government Center North 100 N. Senate Avenue, Room N501 Indianapolis, Indiana 46204 (317) 232-2494
Contact:	Robert Glennon
Assignment:	Larkin & Associates was under contract with the Indiana Office of the Utility Consumer Counselor to review issues pertaining to Statement of Financial Accounting Standards No. 106 (FAS 106) and the rate recovery of costs for postretirement benefits other than pensions (OPEB) requested by Indiana Gas Company (IGC). Our testimony summarized the background and requirements of FAS 106; discussed IGC's proposed ratemaking treatment of FAS 106; identified concerns regarding the FAS 106 accrual, and recommended alternatives to full accrual for recovery of OPEB expenses through rates.
Key Participants:	Hugh Larkin, Jr.
Geographic Location:	Indianapolis, Indiana
Contract Duration:	1993

Connecticut Natural Gas Corporation; Docket No. 93-02-04

Client:	State of Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051-2644 (860) 827-2900
Contact:	Richard Sobolewski
Assignment:	Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review the rate increase request by Connecticut Natural Gas Corporation. Issues addressed: Rate Base; including plant additions, accumulated depreciation - plant additions, air conditioning rebate program, working capital - cost of gas, working capital - O&M, deferred credits, hardship arrearage forgiveness program. Operating Income; including IS mechanism, residential late payment charge revenues, sale of automatic meter reading assets, production and distribution - LNG facility, rent expense - O&A center, payroll, employee benefits, pension expense, removal of certain employee benefits, matching gift program, personal use of Company vehicles, directors' and officers' liability insurance, outside services - legal, rate case expense, economic development expense, uncollectibles, lobbying expense adjustment - outside services, membership dues, adjustment for miscellaneous expenses, general inflation adjustment, CIS/DCIS depreciation expense, property taxes, income tax expense, interest synchronization.
Key Participants:	Hugh Larkin, Jr. Helmuth W. Schultz, III Donna DeRonne
Geographic Location:	Hartford, Connecticut
Contract Duration:	June - October, 1993

Minnegasco; Docket No. G008/C-91-942

Client: Minnesota Department of Public Service
Suite 200
121 7th Place East
St. Paul, Minnesota 55101-2145
(612) 297-1773

Contact: Marya White, Supervisor
Sundra Bender

Assignment: Larkin & Associates was assigned to review the January 20, 1993 filing of the Minnesota Alliance for Fair Competition against Minnegasco (MAC) and to analyze the July 1993 filing by Minnegasco in response to MAC's filing. Larkin & Associates' analysis of Minnegasco's July 1993 filing was intended to determine whether Minnegasco had adequately responded to the allegations made by MAC. Also and more specifically, Larkin & Associates was requested to determine whether Minnegasco's Cost Apportionment Manual provides a means of:

1) Determining whether costs can be identified;
2) Determining if an allocation process is reasonable such that: a) all direct costs are allocated, b) the remaining common costs to be allocated are reasonable; and c) the allocator being used is reasonable.
3) Determining if the allocation process is auditable; and
4) Determining if an audit trail exists.

Key Participants: Helmuth W. Schultz, III

Geographic Location: St. Paul, Minnesota

Contract Duration: 1993

Mountain Fuel Supply Company; Docket No. 93-057-01

Client: Committee of Consumer Services
Heber M. Wells Building
160 East 300 South, P.0. Box 146782
Salt Lake City, Utah 84114-6782
(801) 530-6674

Contact: Dan Gimble

Assignment: Larkin & Associates was under contract with the Committee of Consumer Services to review the application for an increase in rates and charges filed by Mountain Fuel Supply Company on April 2, 1993. Our testimony addressed the Company-proclaimed impact on its working gas inventory and labor requirements resulting from FERC Order 636. Another issue of paramount importance was unbilled revenue. Larkin & Associates proposed that the Company's cumulative unbilled revenue balance be amortized into rates over a period of five years. Other issues addressed in testimony were: Cash Working Capital; Accumulated Deferred Income Taxes; "Banked" Vacation; Equal Payment Plan; Payroll Expense; Overtime Expense; Stock Purchase Plan Expense; O&M Expense Percentage; Payroll Taxes; Executive Incentive Retirement Plan; Supplemental Executive Retirement Plan; Postretirement Benefits Other Than Pensions; and Consolidated Income Taxes.

Key Participants: Hugh Larkin, Jr.

Geographic Location: Salt Lake City, Utah

Contract Duration: May 1993 - October 1993

Citizens Utilities-Arizona Gas Division, Docket No. E-1032-93-111

Client: Residential Utility Consumer Office
2828 N. Central Avenue, Suite 1200
Phoenix, Arizona 85004
(602) 279-5659

Contact: Marylee Diaz Cortez

Assignment: Larkin and Associates was retained by Residential Utility Consumer Office to review Citizens Utilities-Arizona Gas Division's rate increase request. Testimony addressed the following issues: Construction Work in Progress; Acquisition Adjustment; Common Plant - Stamford Administrative Office; AGD Four-Factor Allocator Specific SAO Common Plant Disallowances; Harvey, Louisiana Administrative Office Plant; Accumulated Depreciation; Accumulated Deferred Income Taxes; Materials & Supplies; Customer Deposits; Cost-Free Capital -- Warm Spirit Program; Cash Working Capital; Revenue Lag; Amortizations; Payroll Lag; Payroll Tax Lag; Check Clearing Lag; Income Tax; Revenue Annualization; Weather Normalization; Postage Expense; Rate Case Expense; Stamford Administrative Office Expenses; Harvey Administrative Office Expense; Payroll Expense; Payroll Taxes; Employee Benefits; Pension Expense; Supplemental Pension Expense; Group Medical Insurance Expense; FAS 106 Accrual; Incentive Compensation; Directors' and Officers' Liability Insurance; Target: Excellence quality program training cost; Supplier Billing Error; Depreciation Expense; Industry Association Dues; "Wally Bucks" as promotional expense; Donations; Social Organization Dues; Other Expenses that Are Inappropriate for Ratemaking; Interest Synchronization; and Build-out Program.

Key Participants: Ralph C. Smith

Geographic Location: Arizona

Contract Duration: 1993

Philadelphia Electric Co.; In the Matter of Re: Dennis F. Haley et al v. PECO

Client:	Delaware Valley Chapter PCAUUP 1408 E. Mermaid Lane Philadelphia, Pennsylvania 19118
Contact:	Dennis F. Haley
Assignment:	Larkin & Associates was retained to audit the accounting records of Philadelphia Electric Company's gas operations with a specific focus on the Gas House Heating Service Contract Program. The purpose of our audit was to determine the propriety of the Company's recording of revenue and expenses for the Contract Service Program. In addition, we attempted to determine whether the Contract Service Program was subsidized by ratepayers' monies and whether the price of the program was below an average variable cost.
Key Participants:	Helmuth W. Schultz, III
Geographic Location:	Philadelphia, Pennsylvania
Contract Duration:	1992 - 1993

Indiana Gas Company; Cause No. 39353

Client: Office of Utility Consumer Counselor
Indiana Government Center North
100 N. Senate Avenue, Room N501
Indianapolis, Indiana 46204
(317) 232-2494

Contact: Robert Glennon

Assignment: Review of the request of Indiana Gas Company to increase its rates and provide expert testimony on behalf of the Indiana Office of Utility Consumer Counselor. Issues addressed included: Weather normalized gas sales; the appropriate ratemaking treatment of an acquisition adjustment, intercompany allocations; collection charge revenues and changes in customer levels. In addition, we analyzed and presented testimony regarding the Company's proposal to include a weather "tracking" or weather normalization adjustment clause in residential and commercial space heating rates.

Key Participants: Hugh Larkin, Jr.

Geographic Location: Indianapolis, Indiana

Contract Duration: May through August 1992

The Peoples Natural Gas Company; Docket No. R-00922180

Client:	Pennsylvania Office of Consumer Advocate 555 Walnut Street Forum Place, 5th Floor Harrisburg, PA 17101-1923 (717) 783-5048
Contact:	Kent Murphy
Assignment:	Larkin & Associates was retained by the Pennsylvania Office of Consumer Advocate to review the Peoples Natural Gas Company's application for an increase in rates. We presented direct and rebuttal testimony addressing such issues as: Construction Work in Progress, cash working capital, accounts payable related to materials and supplies, post-retirements benefits other than pensions, payroll expense, employee benefits expense, uncollectibles, Pilot Customer Assistance Plan expenses, outside services expense, injuries and damages expense, and relocation expense.
Key Participants:	Ralph C. Smith
Geographic Location:	Harrisburg, Pennsylvania
Contract Duration:	1992

Southern Union Gas Company

Client:	The Public Utility Regulation Board of The City of El Paso c/o Diamond, Rash, Gordon & Jackson 725 First City National Bank Building El Paso, Texas 79901 (915) 533-2277
Contact:	Norman Gordon
Assignment:	Review of gas Company revenue requirements and prefiled testimony addressing issues resulting from this review. Issues included: Acquisition adjustment amortization, investment tax credit amortization, liability insurance expense and acquisition investigation costs.
Key Participants:	Hugh Larkin, Jr. Ralph C. Smith
Geographic Location:	Austin, Texas
Contract Duration:	1991

United Cities Gas Company; Docket No. 176-717-U

Client:	Kansas Corporation Commission 1500 S.W. Arrowhead Road Topeka, Kansas 66604-4027 (913) 271-3200
Contact:	Dave Dittemore
Assignment:	Audit and review of utility rate increase request. Policy issues addressed included ratemaking treatment of an acquisition adjustment and non-compete agreement. Other issues addressed: pipeline safety deferrals, gas costs, employee benefits and distribution expense.
Key Participants:	Hugh Larkin, Jr.
Geographic Location:	Topeka, Kansas
Contract Duration:	1991

Southwest Gas Corporation; Docket No. U-1551-90-322

Client:	Arizona Corporation Commission 1200 West Washington Street Phoenix Arizona 85007 (602) 542-0745
Contact:	Janice Alward
Assignment:	Review of accounting and revenue requirements of gas utility. Prefiled testimony addressed the following issues: Prepayments, pipe replacement program, marketing and advertising expense, revenues, gain on disposition of property and officers' compensation.
Key Participants:	Hugh Larkin, Jr. Ralph C. Smith Helmuth W. Schultz, III
Geographic Location:	Arizona
Contract Duration:	1991

Southwest Gas Corporation - Purchased Gas Adjustment Report; Rebuttal; Docket Nos. U-1551-89-102; U-1551-89-103; and U-1551-91-069

Client:	Arizona Corporation Commission 1200 West Washington Street Phoenix, Arizona 85007 (602) 542-0745
Contact:	Janice Alward Chris Kempley
Assignment:	Larkin & Associates addressed certain issues and recommendations made in Southwest's prepared direct testimony. The following topics were addressed: Lost and Unaccounted for Gas; Adjustment to Account 191 for Tier-2 Gas Cost Corrections; Santa Fe Margin on System Gas sales to be Credited to Ratepayers; Allocation to Arizona of Santa Fe's Profits on End-User Sales.
Key Participants:	Hugh Larkin, Jr. Ralph C. Smith Helmuth W. Schultz, III
Geographic Location:	Arizona
Contract Duration:	1991

Equitable Gas Company; Docket No. R-901595

Client: Pennsylvania Public Utilities Commission
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923
(717) 783-5048

Contact: Kent Murphy

Assignment: Rate base, operating income and revenue requirement issues including Company's capitalization of promotional allowances, projected plant additions, accumulated depreciation, materials and supplies, accounts payable related to CWIP, customer deposits, provision for rate refund, cash working capital (billing lag collection lag, other taxes lag, income tax lag, interest expense lag) residential sales, take-or-pay liability amortization, uncollectible, advertising & promotional expense, recoveries of theft of gas, association dues, employee retirements, projection of work force, pension expense, marketing study, energy assistance program, depreciation, gross receipts tax, customer deposit interest and income tax expense.

Key Participants: Ralph C. Smith

Geographic Location: Harrisburg

Contract Duration: 1990

Mountaineer Gas Company; Case No. 89-640-G-42T

Client: Consumer Advocate Division
West Virginia Public Service Commission
7th Floor, Union Building
723 Kanawha Boulevard, East
Charleston, West Virginia 25301
(304) 558-0526

Contact: Billy Jack Gregg

Assignment: Reviewed Company's rate base, including plant in service and accumulated depreciation, sale of liquid propane gas plant, plant acquisition from Columbia. Materials and supplies inventory; prepayments, including winter service and winter storage; working cash allowance; other rate base reductions, including customer deposits, accrued vacation pay, rate refunds, unclaimed accounts. Reviewed Company's operating income, including operating revenues; weather normalization, commercial and industrial sales growth. Miscellaneous revenue, including sale of liquid propane gas plant; operations and maintenance expense, including payroll, pension expense, uncollectibles expense, rate year P.S.C. expense, expense for mandatory drug/alcohol testing, legal and outside services expense, affiliated transactions, rate case expense, expense for lease of tape drives, truck lease expense, expense for electricity used by computer room, expense for rent-corporate office, inflation adjustment, EDP lease expense, advertising expense, computer software expense. Taxes other than income, including payroll taxes. Income taxes. Reviewed capital structure and rate of return.

Key Participants: Hugh Larkin, Jr.

Geographic Location: West Virginia

Contract Duration: 1989

Northern States Power Company - Gas; Docket No. G002/GR-86-160

Client:	Office of the Attorney General 340 Bremer Tower Minnesota Street at 7th Place St. Paul, Minnesota 55101 (612) 297-4611
Contact:	Dennis Ahlers Curt Nelson
Assignment:	Address impact of Tax Reform Act of 1986 on gas distribution utility operations including reduction in corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC and timing of TRA-associated impacts upon utility rates.
Key Participants:	Hugh Larkin, Jr. Ralph C. Smith
Geographic Location:	Minnesota
Contract Duration:	1986-1987

Connecticut Natural Gas Corporation; Docket No. 87-01-03

Client:	Department of Public Utility Control - Prosecutorial Division State of Connecticut One Central Park Plaza Room 105 New Britain, Connecticut 06051 (203) 827-2603
Contact:	Steve Cadwallader William Darcey James Meehan
Assignment:	To determine the appropriate regulatory treatment associated with various changes in the tax code caused by tax reform and determine the impact of the Tax Reform Act on the cost of service and revenue requirements. Further, examine unbilled revenue, allowance for bad debt, inventory storage costs, cash flow changes associated with the TRA, excess accumulated deferred income tax reserve and adjustments to CNG's calculations.
Key Participants:	Hugh Larkin, Jr. Helmuth W. Schultz, III Ralph C. Smith
Geographic Location:	Connecticut
Contract Duration:	December 1986 - May 1987

JOHN B. LEGLER, Ph.D.

1040 St. Andrew Court
Bogart, GA 30622
(706) 549-0092

Department of Banking and Finance
Terry College of Business, University of Georgia
Athens, GA 30602-6253
(706) 542-3634

Present Position:
- Professor of Banking and Finance, 1977- present.
- Research Associate, National Bureau of Economic Research, 1986 - present.

Academic Background:
- B.A. Allegheny College, Meadville, Pennsylvania, 1962
- M.S. Purdue University, 1965
- Ph.D. Purdue University, January 1967

Previous Teaching and Administrative Experience:
- Director, Georgia Economic Forecasting Proj., College of Business Administration, 1974-82.
- University of Georgia: Associate Professor of Banking and Finance, 1971-77.
- Institute of Government, University of Georgia: Administrator, Research Division, 1972-74.
- Institute of Government, University of Georgia: Head, Public Finance Section, 1971-74.
- Washington University: Assistant Professor of Economics, 1966-71.
- Washington University: Assistant Director, Institute for Urban and Regional Studies, 1966-1971. (Acting Director, 2/68-8/68).
- Herman C. Krannert Graduate School of Industrial Administration, Purdue University: Graduate Instructor, 1962-1966.
- Temporary Commission in City Finances, New York City: Research Aide, 1965.
- Editor: Georgia Government Review, 1974-1975.

Memberships:

Appointed by Governor Miller to the Joint Study Commission on Revenue Structure, 1993- present. Serve on property and wealth taxation subcommittee.
The Economic History Association
Beta Gamma Sigma

Expert Witness:

Appearances before:

Alabama Public Service Commission, Arizona Corporations Commission,
Public Utilities Commission of California,
Connecticut Department of Public Utility Control,
Florida Public Service Commission,
Georgia Public Service Commission,

Hawaii Public Utilities Commission,
Illinois Commerce Commission,

Kentucky Public Service Commission,
Louisiana Public Service Commission,
Maine Public Service Commission,
Public Service Commission of Maryland,
Michigan Public Service Commission,
Mississippi Public Service Commission,
Public Utilities Commission of Ohio,
State of New Jersey Board of Regulatory Commissioners,
New Mexico State Corporations Commission,
North Carolina Utilities Commission,
South Carolina Public Service Commission,
Public Utility Commission of Texas,
Public Service Commission of Utah,
Virginia State Corporation Commission,
Washington Utilities and Transportation Commission,
Georgia Legislature: House Utilities Study Committee,
Georgia: State Board of Equalization,
Chatham County (Savannah) Superior Court,
Nuclear Regulatory Commission,
National Association of Security Dealers, Inc. (Arbitration),
Federal Energy Regulatory Commission

Grants:

National Science Foundation grant in 1985, 1987, 1989 and 1991

Publications:

Articles:

(With C. David Billings) "Factors Affecting Educational Opportunity and Their Implications for School Finance Reform: An Empirical Study," Journal of Law and Education, (October 1975).

(With Cheng F. Lee) "An Application of the Box-Jenkins ARIMA Model to Regional Economics Forecasting: Georgia as a Case Study," Proceedings of the American Statistical Association, Business and Economics Statistics Section, 1975.

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Primary responsibility for Chapters 14 and 15 in James C. Bonbright, Albert L. Danielson and David R. Kamerschen (With assistance of John B. Legler) Principles of Public Utility Rates (Public Utility Reports,Inc., Arlington, Virginia, 1988).

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Monographs:

(With C. David Billings, John Kaatz and Willys Knight) State Taxation in Georgia: Facts and Analyses, University System of Georgia, 1972.

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Book Reviews:

Fiscal Federalism: Quantitative Studies, Edited by Harvey S. Rosen in The Journal of Economic History, Vol. L, No. 1, March 1990.

What You Should Know About the Value Added Tax, by Dan Troop Smith, James B. Webber and Carol M. Cerf in The Accounting Review, Vol. XLIX, No. 3, July 1974.

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Comments:

"Taxation and Environment Improvement," Proceedings of the Sixty-Third Annual Conference, National Tax Association, September 1970.

"Discussion of Paper on Sales Taxation," Proceedings of the Sixty-Fourth Annual Conference, National Tax Association, September 1971.

"Discussion of Paper on the Economics of Social Class and Metropolitan Local Government," Proceedings of the Sixty-Seventh Annual Conference, National Tax Association - Tax Institute of America, October 1974.

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Working and Occasional Papers:

(With C. David Billings) "The Influence of Expenditures and Race on Educational Achievement," Institute of Government, University of Georgia, RP-7301, September 1973.

"Regional Trends in State and Local Government Employment and Compensation," Metropolitan Studies Program, Maxwell School, Syracuse University, Occasional Paper No. 15, January 1975.

Miscellaneous Publications:

"Economic Outlook Georgia: A Review of 1975 and Highlights of the 1976 and 1977 Forecasts," Georgia Business, Vol. 36, No. 2, March-April 1976.

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(With Jeffrey Chandler) "The Georgia Stock Price Index," Georgia Business, Vol. 38, No. 1, January-February 1978.

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"Economic Outlook Georgia," Georgia Business, Vol. 40, No. 1, January-February 1980.

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Current Position

Public Utility Attorney and Consultant, Selinsgrove, PA. 1994 to present. I provide legal, consulting, and expert witness services to various organizations interested in the regulation of public utilities.

Previous Positions

Lecturer in Computer Science, Susquehanna University, Selinsgrove, PA. 1993 to 2000.

Senior Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1990 to 1994. I supervised the administrative and technical staff and shared with one other senior attorney the supervision of a legal staff of 14 attorneys.

Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1983 to 1990.

Associate, Laws and Staruch, Harrisburg, PA. 1981 to 1983.

Law Clerk, U.S. Environmental Protection Agency, Washington, DC. 1980 to 1981.

Research Assistant, Rockville Consulting Group, Washington, DC. 1979.

Current Professional Activities

Member, American Bar Association, Public Utility Law Section.

Member, American Water Works Association.

Admitted to practice law before the Supreme Court of Pennsylvania, the New York State Court of Appeals, the United States District Court for the Middle District of Pennsylvania, the United States Court of Appeals for the Third Circuit, and the Supreme Court of the United States.

Previous Professional Activities

Member, American Water Works Association, Rates and Charges Subcommittee, 1998-2001.

Member, Federal Advisory Committee on Disinfectants and Disinfection By-Products in Drinking Water, U.S. Environmental Protection Agency, Washington, DC. 1992 to 1994.

Chair, Water Committee, National Association of State Utility Consumer Advocates, Washington, DC. 1990 to 1994; member of committee from 1988 to 1990.

Member, Board of Directors, Pennsylvania Energy Development Authority, Harrisburg, PA. 1990 to 1994.

Member, Small Water Systems Advisory Committee, Pennsylvania Department of Environmental Resources, Harrisburg, PA. 1990 to 1992.

Member, Ad Hoc Committee on Emissions Control and Acid Rain Compliance, National Association of State Utility Consumer Advocates, 1991.

Member, Nitrogen Oxides Subcommittee of the Acid Rain Advisory Committee, U.S. Environmental Protection Agency, Washington DC. 1991.

Education

J.D. with Honors, George Washington University, Washington, DC. 1981.

B.A. with Distinction in Political Science, Pennsylvania State University, University Park, PA. 1978.

Publications and Presentations

"Quality of Service Issues," a speech to the Pennsylvania Public Utility Commission Consumer Conference, State College, PA. 1988.

K.L. Pape and S.J. Rubin, "Current Developments in Water Utility Law," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 1990.

Presentation on Water Utility Holding Companies to the Annual Meeting of the National Association of State Utility Consumer Advocates, Orlando, FL. 1990.

"How the OCA Approaches Quality of Service Issues," a speech to the Pennsylvania Chapter of the National Association of Water Companies. 1991.

Presentation on the Safe Drinking Water Act to the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Seattle, WA. 1991.

"A Consumer Advocate's View of Federal Pre-emption in Electric Utility Cases," a speech to the Pennsylvania Public Utility Commission Electricity Conference. 1991.

Workshop on Safe Drinking Water Act Compliance Issues at the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Washington, DC. 1992.

Formal Discussant, Regional Acid Rain Workshop, U.S. Environmental Protection Agency and National Regulatory Research Institute, Charlotte, NC. 1992.

S.J. Rubin and S.P. O'Neal, "A Quantitative Assessment of the Viability of Small Water Systems in Pennsylvania," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference,* National Regulatory Research Institute (Columbus, OH 1992), IV:79-97.

"The OCA's Concerns About Drinking Water," a speech to the Pennsylvania Public Utility Commission Water Conference. 1992.

Member, Technical Horizons Panel, Annual Meeting of the National Association of Water Companies, Hilton Head, SC. 1992.

M.D. Klein and S.J. Rubin, "Water and Sewer -- Update on Clean Streams, Safe Drinking Water, Waste Disposal and Pennvest," *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 1992.

Presentation on Small Water System Viability to the Technical Assistance Center for Small Water Companies, Pa. Department of Environmental Resources, Harrisburg, PA. 1993

"The Results Through a Public Service Commission Lens," speaker and participant in panel discussion at Symposium: "Impact of EPA's Allowance Auction," Washington, DC, sponsored by AER*X. 1993.

"The Hottest Legislative Issue of Today -- Reauthorization of the Safe Drinking Water Act," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, San Antonio, TX. 1993.

"Water Service in the Year 2000," a speech to the Conference: "Utilities and Public Policy III: The Challenges of Change," sponsored by the Pennsylvania Public Utility Commission and the Pennsylvania State University, University Park, PA. 1993.

"Government Regulation of the Drinking Water Supply: Is it Properly Focused?," speaker and participant in panel discussion at the National Consumers League's Forum on Drinking Water Safety and Quality, Washington, DC. 1993. Reprinted in *Rural Water*, Vol. 15 No. 1 (Spring 1994), pages 13-16.

"Telephone Penetration Rates for Renters in Pennsylvania," a study prepared for the Pennsylvania Office of Consumer Advocate. 1993.

"Zealous Advocacy, Ethical Limitations and Considerations," participant in panel discussion at "Continuing Legal Education in Ethics for Pennsylvania Lawyers," sponsored by the Office of General Counsel, Commonwealth of Pennsylvania, State College, PA. 1993.

"Serving the Customer," participant in panel discussion at the Annual Conference of the National Association of Water Companies, Williamsburg, VA. 1993.

"A Simple, Inexpensive, Quantitative Method to Assess the Viability of Small Water Systems," a speech to the Water Supply Symposium, New York Section of the American Water Works Association, Syracuse, NY. 1993.

S.J. Rubin, "Are Water Rates Becoming Unaffordable?," *Journal American Water Works Association*, Vol. 86, No. 2 (February 1994), pages 79-86.

"Why Water Rates Will Double (If We're Lucky): Federal Drinking Water Policy and Its Effect on New England," a briefing for the New England Conference of Public Utilities Commissioners, Andover, MA. 1994.

"Are Water Rates Becoming Unaffordable?," a speech to the Legislative and Regulatory Conference, Association of Metropolitan Water Agencies, Washington, DC. 1994.

"Relationships: Drinking Water, Health, Risk and Affordability," speaker and participant in panel discussion at the Annual Meeting of the Southeastern Association of Regulatory Commissioners, Charleston, SC. 1994.

"Small System Viability: Assessment Methods and Implementation Issues," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, New York, NY. 1994.

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"Safe Drinking Water Act Compliance -- Ratemaking Implications," speaker at the National Conference of Regulatory Attorneys, Scottsdale, AZ. 1995. Reprinted in *Water*, Vol. 36, No. 2 (Summer 1995), pages 28-29.

S.J. Rubin, "Water: Why Isn't it Free? The Case of Small Utilities in Pennsylvania," *Utilities, Consumers & Public Policy: Issues of Quality, Affordability, and Competition, Proceedings of the Fourth Utilities, Consumers and Public Policy Conference* (Pennsylvania State University 1995), pages 177-183.

S.J. Rubin, "Water Rates: An Affordable Housing Issue?," *Home Energy*, Vol. 12 No. 4 (July/August 1995), page 37.

Speaker and participant in the Water Policy Forum, sponsored by the National Association of Water Companies, Naples, FL. 1995.

Participant in panel discussion on "The Efficient and Effective Maintenance and Delivery of Potable Water at Affordable Rates to the People of New Jersey," at The New Advocacy: Protecting Consumers in the Emerging Era of Utility Competition, a conference sponsored by the New Jersey Division of the Ratepayer Advocate, Newark, NJ. 1995.

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"Recent Federal Legislation Affecting Drinking Water Utilities," speaker at Pennsylvania Public Utility Law Conference, Pennsylvania Bar Institute, Hershey, PA. 1996.

"Clean Water at Affordable Rates: A Ratepayers Conference," moderator at symposium sponsored by the New Jersey Division of Ratepayer Advocate, Trenton, NJ. 1996.

"Water Workshop: How New Laws Will Affect the Economic Regulation of the Water Industry," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, San Francisco, CA. 1996.

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"Capacity Development in the Water Industry," speaker at the Annual Meeting of the National Association of Regulatory Utility Commissioners, Boston, MA. 1997.

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Scott J. Rubin, "Estimating the Effect of Different Arsenic Maximum Contaminant Levels on the Affordability of Water Service," prepared for the American Water Works Association. 2000.

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Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division, Pa. Public Utility Commission, Docket R-00922404. 1992. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate.

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The Petition on Behalf of Gordon's Corner Water Company for an Increase in Rates, New Jersey Board of Public Utilities, Docket No. WR94020037. 1994. Concerning revenue requirements and rate design, on behalf of the New Jersey Division of Ratepayer Advocate.

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In the Matter of the Application of Potomac Electric Power Company for Approval of its Third Least-Cost Plan, D.C. Public Service Commission, Formal Case No. 917, Phase II. 1995. Concerning Clean Air Act implementation and environmental externalities, on behalf of the District of Columbia Office of the People's Counsel.

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of the Dayton Power and Light Company and Related Matters, Ohio Public Utilities Commission, Case

No. 94-105-EL-EFC. 1995. Concerning Clean Air Act implementation (case settled before testimony was filed), on behalf of the Office of the Ohio Consumers' Counsel.

Kennebec Water District Proposed Increase in Rates, Maine Public Utilities Commission, Docket No. 95-091. 1995. Concerning the reasonableness of planning decisions and the relationship between a publicly owned water district and a very large industrial customer, on behalf of the Maine Public Advocate.

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In the Matter of the 1995 Long-Term Electric Forecast Report of the Cincinnati Gas & Electric Company, Public Utilities Commission of Ohio, Case No. 95-203-EL-FOR, and *In the Matter of the Two-Year Review of the Cincinnati Gas & Electric Company's Environmental Compliance Plan Pursuant to Section 4913.05, Revised Cost*, Case No. 95-747-EL-ECP. 1996. Concerning the reasonableness of the utility's long-range supply and demand-management plans, the reasonableness of its plan for complying with the Clean Air Act Amendments of 1990, and discussing methods to ensure the provision of utility service to low-income customers, on behalf of the Office of the Ohio Consumers' Counsel..

In the Matter of Notice of the Adjustment of the Rates of Kentucky-American Water Company, Kentucky Public Service Commission, Case No. 95-554. 1996. Concerning rate design, cost of service, and sales forecast issues, on behalf of the Kentucky Office of Attorney General.

In the Matter of the Application of Citizens Utilities Company for a Hearing to Determine the Fair Value of its Properties for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Provide such Rate of Return, Arizona Corporation Commission, Docket Nos. E-1032-95-417, *et al.* 1996. Concerning rate design, cost of service, and the price elasticity of water demand, on behalf of the Arizona Residential Utility Consumer Office.

Cochrane v. Bangor Hydro-Electric Company, Maine Public Utilities Commission, Docket No. 96-053. 1996. Concerning regulatory requirements for an electric utility to engage in unregulated business enterprises, on behalf of the Maine Public Advocate.

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters, Public Utilities Commission of Ohio, Case No. 96-106-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters, Public Utilities Commission of Ohio, Case Nos. 96-107-EL-EFC and 96-108-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters, Public

Utilities Commission of Ohio, Case Nos. 96-101-EL-EFC and 96-102-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company (Phase II), Kentucky Public Service Commission, Docket No. 93-434. 1997. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Public Service Litigation Branch.

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters, Public Utilities Commission of Ohio, Case No. 96-103-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

Bangor Hydro-Electric Company Petition for Temporary Rate Increase, Maine Public Utilities Commission, Docket No. 97-201. 1997. Concerning the reasonableness of granting an electric utility's request for emergency rate relief, and related issues, on behalf of the Maine Public Advocate.

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In the Matter of the Petition of Valley Road Sewerage Company for a Revision in Rates and Charges for Water Service, New Jersey Board of Public Utilities, Docket No. WR92080846J. 1997. Concerning the revenue requirements and rate design for a wastewater treatment utility, on behalf of the New Jersey Division of Ratepayer Advocate.

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In the Matter of Petition of Seaview Water Company for an Increase in Rates for Water Service, New Jersey Board of Public Utilities, Docket No. WR98040193. 1999. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters, Public Utilities Commission of Ohio, Case Nos. 98-101-EL-EFC and 98-102-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Dayton Power and Light Company and Related Matters, Public Utilities Commission of Ohio, Case No. 98-105-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters, Public Utilities Commission of Ohio, Case No. 99-106-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

County of Suffolk, et al. v. Long Island Lighting Company, et al., U.S. District Court for the Eastern District of New York, Case No. 87-CV-0646. 2000. Submitted two affidavits concerning the calculation and collection of court-ordered refunds to utility customers, on behalf of counsel for the plaintiffs.

Northern Utilities, Inc., Petition for Waivers from Chapter 820, Maine Public Utilities Commission, Docket No. 99-254. 2000. Concerning the standards and requirements for defining and separating a natural gas utility's core and non-core business functions, on behalf of the Maine Public Advocate.

Notice of Adjustment of the Rates of Kentucky-American Water Company, Kentucky Public Service Commission, Case No. 2000-120. 2000. Concerning the appropriate methods for allocating costs and designing rates, on behalf of the Kentucky Office of Attorney General.

In the Matter of the Petition of Gordon's Corner Water Company for an Increase in Rates and Charges for Water Service, New Jersey Board of Public Utilities, Docket No. WR00050304. 2000. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

Testimony concerning Arsenic in Drinking Water: An Update on the Science, Benefits, and Costs, Committee on Science, United States House of Representatives. 2001. Concerning the effects on low-income households and small communities from a more stringent regulation of arsenic in drinking water.

In the Matter of the Application of The Cincinnati Gas & Electric Company for an Increase in Gas Rates in its Service Territory, Public Utilities Commission of Ohio, Case No. 01-1228-GA-AIR, *et al.* 2002. Concerning the need for and structure of a special rider and alternative form of regulation for an accelerated main replacement program, on behalf of the Ohio Consumers' Counsel.

Pennsylvania State Treasurer's Hearing on Enron and Corporate Governance Issues. 2002. Concerning Enron's role in Pennsylvania's electricity market and related issues, on behalf of the Pennsylvania AFL-CIO.

An Investigation into the Feasibility and Advisability of Kentucky-American Water Company's Proposed Solution to its Water Supply Deficit, Kentucky Public Service Commission, Case No. 2001-00117. 2002. Concerning water supply planning, regulatory oversight, and related issue, on behalf of the Kentucky Office of Attorney General.

Joint Application of Pennsylvania-American Water Company and Thames Water Aqua Holdings GmbH, Pennsylvania Public Utility Commission, Docket Nos. A-212285F0096 and A-230073F0004. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE AG and Thames Water Aqua Holdings GmbH, Kentucky Public Service Commission, Case No. 2002-00018. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Kentucky Office of Attorney General.

References

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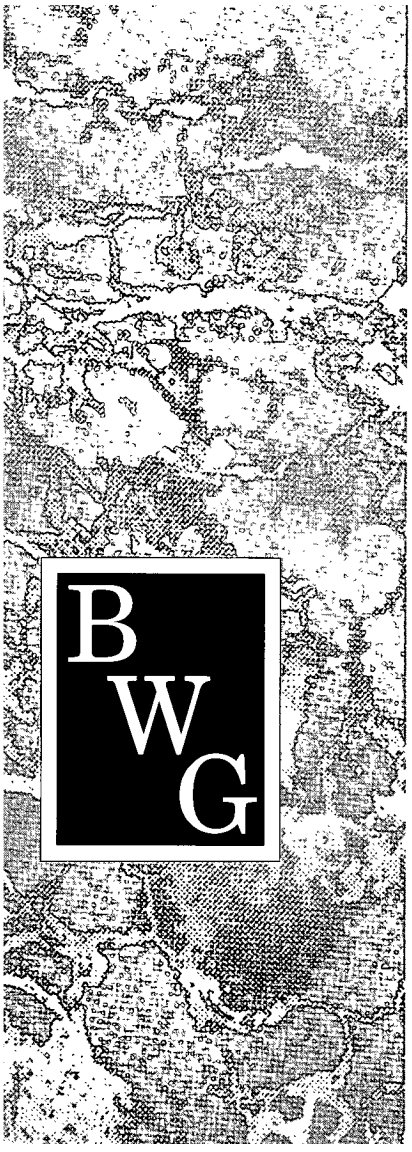

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Response to Request for Proposal

by Barrington-Wellesley Group, Inc.

05/29/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

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ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

A Proposal to Provide Consulting Services In Connection with the Montana-Dakota Utilities Gas Rate Increase Request

For the North Dakota
Public Service Commission

Case No. PU-399-02-183

May 30, 2002

Barrington-Wellesley Group, Inc.
2479 Lanam Ridge Road, Nashville, IN 47448

A Proposal to Provide Consulting Services In Connection with the Montana-Dakota Utilities Gas Rate Increase Request

For the
North Dakota Public Service Commission

Case No. PU-399-02-183

Primary Contact:

Mr. Michael A. Laros
Managing Director and Co-President
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e-mail: laros@bwgi.com

Barrington-Wellesley Group, Inc.
Management Consultants
2479 Lanam Ridge Road • Nashville, IN 47448 • Tel: (812) 988-0190 • Fax (812) 988-0194

May 30, 2002

North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480

Attention: Mr. Mike Diller, Director of Accounting

Dear Mr. Diller,

The Barrington-Wellesley Group, Inc. (BWG) is pleased to submit the enclosed proposal to provide assistance to the North Dakota Public Service Commission Staff in its investigation of Montana-Dakota Utilities Company's gas rate increase request. BWG is proposing to offer assistance related to the appropriate level of investment in North Dakota and the appropriate cost of service.

As requested, one original and five copies of the proposal are enclosed.

We are committed to managing our work in a manner that will assure meeting Commission objectives in the most efficient manner possible and look forward to working with you and your associates on this important project.

Please contact me at the above phone number or by email at laros@bwgi.com if you have any questions or require further information.

Thank you for your consideration of our proposal.

Sincerely,

Michael A. Laros

Michael A. Laros
Managing Director

CHAPTER I

STATEMENT OF THE PROJECT

The Barrington-Wellesley Group, Inc. (BWG) is pleased to respond to the May 10, 2002 Request for Proposal (RFP) from the North Dakota Public Service Commission ("NDPSC" or "Commission") for an independent consultant to investigate, analyze and provide testimony regarding the fairness and reasonableness of Montana-Dakota Utilities' ("MDU" or "Company") proposed gas rates. This chapter presents a brief overview of the Company, describes our understanding of the objectives and scope of the consulting assignment, and summarizes our proposal.

Background

On April 12, 2002, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., filed a Natural Gas Rate Increase Application with the North Dakota Public Service Commission. This application was assigned Case No. PU-399-02-183.

Montana-Dakota Utilities sells natural gas at retail, serving over 213,000 residential, commercial and industrial customers located in 141 communities and adjacent rural areas as of December 31, 2001, and provides natural gas transportation services to certain customers on its system. A significant portion of these customers have retail rates regulated by the NDPSC. MDU Resources Group acquired Great Plains Natural Gas (Great Plains) in July 2000. Great Plains also provides retail natural gas service in North Dakota but is not part of the current rate proceeding.

MDU Resources Group – Natural Gas Distribution Division, comprised of MDU and Great Plains, and operating in five northern plains states, contributed $0.7 million, $4.8 million and $3.2 million (0.5%, 4.4%, and 3.8%) to consolidated earnings on common stock in 2001, 2000 and 1999, respectively. The decrease in earnings in 2001 is attributed to lower sales volumes, largely the result of weather in the fourth quarter which was 22 percent warmer than the previous year, and higher operation and maintenance expenses, primarily increased payroll costs and higher bad debt expense. Lower average realized rates, return on natural gas storage, demand and prepaid commodity balances, and decreased service and repair margins also added to the earnings decline. The increase in earnings from 1999 to 2000 was also largely the result of weather. Degree days as a percent of normal were 94.5%, 100.4% and 88.8% in 2001, 2000 and 1999, respectively. The average cost of natural gas increased from $3.56 per decatherm in 1999 to $5.50 per decatherm in 2001.

For the three months ended March 31, 2002, earnings at MDU Resources Group's natural gas distribution segment increased to $4.5 million, compared to $2.7 million in the same period in 2001. This increase was due to slightly higher retail sales, increased returns on natural gas held in storage, higher non-regulated service and repair margins and lower operation and maintenance expense.

Project Objectives and Scope

BWG proposes to provide assistance related to rate base and cost of service issues. Related to those two areas, our work will include analyzing and reviewing the filing, preparing and conducting discovery as required, preparing monthly reports of discovery, conclusions and findings, preparing and filing written testimony, providing oral testimony, assisting staff in preparing cross-examination of the witnesses of other parties to the proceeding, and assisting the staff with the preparation of proposed findings of fact.

The Commission Staff has provided the following direction in the RFP related to rate base and cost of service issues. We have relied on these representations in developing our estimate of time required to complete the assignment contained in this proposal.

Rate Base -- "The rate base determination is not nearly as critical in terms of rate impact as is establishing the appropriate cost of service. Therefore, work in this area should be limited in scope and should primarily rely on a review of the last rate case and historical comparisons. Annual reports are filed with the Commission and include all rate base components. MDU does not seek a return on working capital in this case. Staff calculated cash working capital in MDU's last rate case and the resulting impact to rates was minimal. Therefore, rate base will not require a cash working capital calculation."

Cost of service -- "In 2001, 80% of MDU's revenues were spent on the cost of gas. Therefore, a critical element of cost of service is the appropriate level of weather-normalized sales. The cost of service portion will also require a strong review of other operating and maintenance expenses."

Proposal Summary

BWG is well-qualified to provide the assistance required by the Commission related to rate base and cost of service issues. Our proposed Project Director, Michael Laros, CMC, is a BWG Managing Director and Co-founder and has over twenty-five years of utility consulting experience. He has testified on a variety of utility management issues before various State regulatory commissions and the FERC. Supporting Laros are David P. Vondle, CMC, and Joel F. Jeanson, CPA, both of whom have significant experience in the natural gas distribution utility industry. The combination of consulting and direct gas utility industry experience represented by the project team will provide the assurance that all relevant issues related to rate base and cost of service will be addressed.

We are proposing a work plan requiring an estimated 250 professional staff hours to complete the assignment. We expect to start this project in June 2002 in order to satisfy Commission requirements that the investigation and written testimony be completed by August 30, 2002. We plan to work closely with the Staff and to provide all information requested in the RFP to aid in its monitoring of the progress of our work.

Organization of this Proposal

The remaining chapters describe BWG's proposed technical approach, experience, and project costs. These chapters are organized as follows:

- Chapter II describes BWG's timeline and preliminary work plan. Tasks are described in sufficient depth to afford the Commission and staff a thorough understanding of our work plan. After orientation, initial interviews, and preliminary analysis, a final detailed work plan will be prepared and submitted to the Commission Staff for approval.

- Chapter III describes our proposed project organization and the experience and education of each audit team member.

- Chapter IV describes our experience conducting similar projects during the previous five years. For each project completed during the previous five years, we have provided a brief description of the project, including the name of our client, the name, address and telephone number of the responsible official of the client company or organization.

- Chapter V provides our cost estimate for each task including manpower costs, costs of materials and supplies, subcontractor costs, transportation costs and total cost. Manpower costs are broken down to identify the category of personnel, estimated hours, rate per hour and total cost. Also included in this chapter are our estimates of the time required to complete each audit task.

- Chapter VI indicates that BWG has no prior or current relationship with the Company or any other potential parties in this proceeding and certifies our compliance with all applicable EEO laws and regulations as well as our compliance with applicable provisions of the Americans with Disabilities Act of 1991.

CHAPTER II

PROJECT TIMELINE AND WORKPLAN

Introduction

This chapter provides a timeline and summary of the proposed project and preliminary detailed work plans for the two areas included in the proposal – rate base and cost of service – based on the assumption that the successful consultant will be selected by June 12, 2002.

Project Timeline and Work Plan

Phase One: Planning /Work Prioritization *(June 17 – 19)*

- Meet Commission Staff assigned to project.
- Discuss coordination of our task areas with those of other consultants or Commission Staff.
- Obtain relevant documents filed in this proceeding.
- Obtain comments on preliminary work plan contained in this proposal.
- Confirm timing of project and key deadlines.
- Confirm project protocols, including progress reporting and document requests.
- Complete final work plan.

Phase Two: Investigation and Analysis *(June 24 – August 13)*

Task 1: Verify the appropriateness of the proposed rate base.

- Obtain a copy of the approved, detailed rate base from the last rate case
- Obtain a copy of the most recent MDU Gas Annual Report filed with the NDPSC.
- Compare current rate base by plant account to that approved in the last rate case.
- Obtain explanations for significant changes.
- Identify controls in place to ensure that only investments made in North Dakota are included
- Review annual depreciation expense by plant account for reasonableness.
- Develop conclusions and recommendations based on the above steps.
- Discuss conclusions and recommendations with Commission Staff.

Task 2: Verify the appropriate of the proposed cost of service.

- Obtain copies of MDU Gas Annual Report for the last three years.
- Obtain copy of test year actual results and pro forma adjustments.
- Review test year and pro forma adjustments for reasonableness. Specific issues include:
    - Weather-normalized sales volumes
    - Bad debt reserve
    - Staffing levels
    - Allocations
    - Any other costs that appear unreasonable based on our trend analyses and industry experience
- Develop conclusions and recommendations based on the above steps.
- Discuss conclusions and recommendations with Commission Staff.

Phase Three: Prepare Written Testimony *(June 29 – August 30)*

During this phase we will prepare written testimony related to rate base and cost of service based on the work performed and conclusions and recommendations reached in Phase Two. We will review this testimony with Commission Staff prior to filing.

Phase Four: Provide Oral Testimony and Other Assistance *(October 7 & 8)*

During this phase BWG will provide oral testimony as well as assist staff in preparing cross-examination of the witnesses of other parties to the proceeding, and assist staff in the preparation of proposed findings of fact.

Professional Standards

BWG will conduct this work in accordance with generally accepted government auditing standards. These standards are set forth in the booklet entitled *Government Auditing Standards, 1994 Revision* developed by the Comptroller General of the United States and published by the United States General Accounting Office. These standards pertain to auditors' professional qualifications and, among other things, requires auditor independence and that the audit be carefully planned and performed in accordance with a written work plan. In addition, audit findings and conclusions are required to be properly documented in working papers and results are to be communicated in a written report.

Work Products

As requested in the RFP, we will provide Commission Staff with monthly progress reports summarizing the results of discovery as well as our conclusions and recommendations related to rate base and cost of service. We will also prepare and file written testimony and provide oral testimony.

Project Management

The work plans and the related individual consultant task assignments, schedules and time estimates are the basic tools we use to manage a project of this type. In Phase I, we will work with the Staff Project Manager to reach agreement on the final scope of the project, establish the schedule and determine the level of involvement and time commitment of members of the Commission Staff who may participate in the audit. We will also ask the Commission Staff to designate a single individual to serve as our principal point of contact and will ask this individual to assist us by coordinating responses to our information requests.

In our experience, these relatively simple project management techniques are ordinarily sufficient to ensure that an audit is completed on schedule and within budget. The members of our team are committed to making this study successful and we will faithfully fulfill our schedule and time commitments in all phases of the audit.

Conclusion

The Barrington-Wellesley Group, Inc. is very well qualified and committed to successfully performing the services the Commission requires. We have worked extremely well with those that engage us and are respectful of the people and particular conditions in the organizations that are the subject of the reviews. We look forward to meeting the project manager and other members of the Commission Staff in the project to ensure that we have communicated our understanding of the objectives of the assignment and to demonstrate our commitment to the performance of a successful engagement.

CHAPTER III

PROJECT TEAM

Introduction

BWG is proposing a small project team comprised of exceptionally well-qualified consultants to provide the services the Commission requires in the two areas included in the proposal. All of our work will be performed in accordance with detailed work plans to be submitted to the project manager for approval before work in any audit area begins. The BWG Project Director will coordinate all work on the engagement and will be responsible to the Commission for all services performed on this assignment.

Project Team Personnel

The following is a brief introduction of the three members of the project team. Complete resumes are provided at the end of this section of the proposal.

Michael A. Laros. Mr. Laros is a managing director and co-founder of the Barrington-Wellesley Group, Inc. He is a Certified Management Consultant (CMC) with over twenty-five years of consulting experience. He will serve as Project Director and be responsible for directing the project team and coordinating and reporting our activities to the project manager and the Commission.

Mr. Laros was the lead consultant for affiliate earnings in the California energy market in the review of Pacific Gas and Electric's financial condition for the California PUC in the midst of the California energy crisis. He has testified as an expert regarding the reasonableness of utility management practices in a variety of civil litigation matters and in rate proceedings before the Federal Energy Regulatory Commission (FERC), and the California, Illinois, New Jersey, and Ohio state public utility commissions. Mr. Laros received his B.S. degree in industrial distribution from Clarkson College of Technology and an M.B.A. from the University of California, Berkeley.

David P. Vondle. Mr. Vondle, a Certified Management Consultant, brings over twenty-five years of management consulting experience in the utility industry. Vondle will serve as the lead consultant on this project and will be responsible for the day-to-day activities associated with this project.

He has testified as an expert witness in eight different jurisdictions, and has prepared written testimony for each of these appearances as well as others. In 2001, Mr. Vondle testified before the California Public Utility Commission regarding PG&E's gas supply and management practices as part of BWG's review of PG&E's financial solvency. Vondle has also testified before the Tennessee Public Service Commission in connection with the United Cities Gas rate case and prepared written testimony on behalf of West Penn Power in a Pennsylvania rate case and on behalf of United Cities Gas in Tennessee and Kansas rate cases.

A complete list of his expert witness / rate case experience is provided in his resume. Mr. Vondle received his B.S. in Industrial Management from the University of Akron and his M.B.A. from Southern Methodist University.

Joel F. Jeanson. Mr. Jeanson, a C.P.A., has twenty-three years of diversified utility financial management and auditing experience, primarily in the natural gas distribution utility industry. He brings the utility insider perspective to this project, having served as director of accounting, budgeting and management reporting, director of corporate performance, financial director of marketing and operations, and director of auditing in his eighteen years with a major Midwestern natural gas distribution utility. Jeanson will serve as the primary analyst on this project.

Prior to joining Indiana Gas, he was a senior auditor with Arthur Andersen. He is a member of the AICPA and the Indiana CPA Society and a past president of the Indianapolis Chapter of the Institute of Internal Auditors. Mr. Jeanson has a B.S. in business from Indiana University, with distinction, majoring in accounting.

Expert Testimony

Upon request of the Commission, either Mr. Laros or Mr. Vondle will be the firm's principal witness and sponsor of the written testimony. Compensation relating to preparation time, travel and presenting testimony is included for the two-day technical hearing indicated in the RFP. Any additional requirements will be billed at our standard compensation rates as identified in the proposal.

Michael A. Laros

BWG Co-President and Co-Founder

Summary of Qualifications

Mr. Laros is a Managing Director and co-founder of the Barrington-Wellesley Group, Inc. He is a Certified Management Consultant (CMC) with over twenty-five years of management consulting experience. He has particular expertise in the areas of utility restructuring, organizational development and major-project cost effectiveness. He has directed industry restructuring-related assignments for utility and regulatory clients in the U.S, England, Canada, and South Africa. Mr. Laros has testified as an expert regarding the reasonableness of utility management practices in a variety of civil litigation matters and in rate proceedings before the Federal Energy Regulatory Commission (FERC), and the California, Illinois, New Jersey, and Ohio state public utility commissions.

Education

M.B.A.	University of California, Berkeley (1976)
B.S.	Clarkson College of Technology (1969)

Utility Testifying Experience:

- *Expert Witness and Engagement Director* -- reviewed the reasonableness of costs incurred in remediation of electrical violations and other areas of operations regarding the Trans Alaska Pipeline System (TAPS) and provided expert testimony for the State of Alaska in a hearing before the Federal Energy Regulatory Commission.
- *Expert Witness and Engagement Director* – reviewed the reasonableness of the premature retirement of the Connecticut Yankee Atomic Power Plant. Testified before the FERC on behalf of the Connecticut Department of Public Utility Control (CDPUC) regarding the reasonableness of the shutdown and of the economic viability study sponsored by the Company in support of the decision to permanently retire the unit.
- *Expert Witness and Engagement Director* – reviewed the reasonableness of costs incurred by Pacific Gas and Electric in the design and construction of the California portion of a $1.6 billion gas pipeline. Prepared report and filed testimony before the California Public Utility Commission regarding management reasonableness and quantification of unreasonably incurred costs.

Consultant References

Consultant Name	Reference	Relationship
Michael Laros	Kayode Kajopaiye CA Public Utility Comm. 415-703-2557	Client, PG&E Financial Solvency Review
	Randall Speck, Esq. Kaye, Scholer, Fierman, Hayes & Handler 202-682-3510	Attorney for Connecticut DPUC on FERC Rate Case
	Sue Garcia San Diego Gas & Electric 858-650-6189	Client, California PX Price Audit
David P. Vondle	Mark Kent Baumgartner CA Public Utility Comm. 415-703-1978	Client
	Pete Wagner Ill. Commerce Commission 217-524-0727	Client
	J. Alan Gardocky Penn. Public Utility Comm. 717-772-0314	Client
Joel F. Jeanson	Carl L. Chapman, EVP Vectren Corporation 812-491-4208	Former Supervisor
	Paula Yang Los Angeles DWP 213-367-1360	Client
	Jerry Oh CA Public Utility Comm. 415-703-5370	Client

- *Expert Witness and Engagement Director* – of a prospective management audit of the project management practices employed by Public Service Electric & Gas Company during the start-up phase of the Hope Creek nuclear project. The study was the third in a series of three management audits of Hope Creek aimed at providing improvement-oriented recommendations. Testified before the New Jersey Board of Public Utility Commissioners in various phases of the rate case proceedings on the findings of the three audits regarding the reasonableness of PSE&G's management of Hope Creek.
- *Expert Witness and Engagement Director* - Provided litigation support for a major Northeastern utility involved in a civil lawsuit concerning the design and construction of a nuclear power plant. Provided and sponsored expert report quantifying the impact of the A/E's mismanagement of engineering and construction on the nuclear power plant costs.
- *Expert Witness and Engagement Director* – of a retrospective audit of the project management practices employed by Illinois Power on the Clinton nuclear project. Also performed focused studies of the "as-built" schedule, project management staff experience, start-up procedures development, and other specific issues identified by the utility's outside law firm. Testified in various phases of the rate case proceedings before the Illinois Commerce Commission.
- *Expert Witness and Engagement Director* - of reviews of the fuels management practices and procedures of Toledo Edison Co. and Cleveland Electric Illuminating Co. for the Public Utility Commission of Ohio EFC Management/Performance Audit Program. Testified before the PUCO on the reasonableness of the utilities' fuels management practices.

Other Representative Consulting Assignments:

- Lead consultant for affiliate earnings in the California energy market in the review of Pacific Gas and Electric's financial condition for the California PUC in the midst of the California energy crisis. (2001)
- *Engagement Director* - for a large northeastern electric utility on development of a strategic plan for unbundling and restructuring of the utility's transmission business unit incorporating emerging access and pricing issues.
- *Engagement Director* - provided advisory services for the Los Angeles City Council regarding the impact of the California restructuring proposals on the Los Angeles Department of Water and Power.
- *Lead Consultant* – Verification of SDG&E hourly Power Exchange Energy Credit (PX Credit) calculations to ensure compliance with Commission orders and utility advice letters. Assessed the utility's calculation methodology and audited all actual costs included in the PX Credits.
- *Engagement Director* - of organizational and strategic planning studies of the Demand Side Management and Marketing functions for a northeastern utility.

- *Project Manager* - of the Phase 1 retrospective management audit, "Assessment of the Impact of Management Practices on the Construction Expenditures of the Trans-Alaska Pipeline," for the State of Alaska. Review included all aspects of TAPS' $10 billion expenditure for the planning, management, design, and construction of the pipeline, the pump stations, and the Valdez terminal.
- *Project Manager* - of a comprehensive retrospective review of the project management practices employed by Houston Lighting and Power Co. on the South Texas Nuclear Project.
- *Engagement Director* - of audit preparation assignments for two electric utilities conducted in anticipation of commission ordered retrospective management audits of nuclear projects owned by the utility.
- *Assistant Project Manager* - of an in-depth, multiple-sponsor review that resulted in the "Study of the U.S. Utility Industry"; author of the "State of the Art of Engineering and Construction Management Practices" segment of the study. Included site visits and executive interviews covering the evolving project management practices employed by the 32 sponsors, as well as research of the E&C sections of over 40 utility-wide management audits and the management audits of several individual nuclear construction projects.
- *Lead consultant* - on a comprehensive research study of the evolution of nuclear power plant construction in the U.S. and an in-depth analysis of the factors having the greatest impact on controlling costs and minimizing cost overruns. Primary author of the resulting report, entitled "A Survey of Organizational and Contractual Trends in Power Plant Construction," which documented the changes in management practices implemented by utilities to meet their cost, schedule, and quality-assurance responsibilities and to make their involvement commensurate with the financial risk of these major projects.
- *Lead Consultant* - of a review of the fuels management practices of Dairyland Power Cooperative. Conducted an in-depth evaluation of the financing alternatives for a fleet of barges owned by the cooperative. Assisted in a competitive-bid leverage lease evaluation for a cooperative-owned unit train.
- *Consultant* - responsible for evaluating the adequacy of the financial and computer modeling aspects of generation planning performed by Sunflower Electric Cooperative, Inc., to support their decision to build a 280-MW coal plant. Study was conducted as part of a third-party review for the Kansas Corporation Commission.
- *Consultant* - on a comprehensive review of fuels procurement practices and procedures for a major Southeastern electric utility. Assignment included development of a long-range fuels procurement strategy for the company.

Previous Experience

- *Vice President / Director* - Theodore Barry & Associates (1977-1990). Responsible for TB&A's litigation support and utility industry competitive restructuring practices (1986-1990).

- *Partner* - Laros & Menezes Associates (1975-1977*).* Provided consulting services to specialty contractors and construction trade associations in the areas of planning, management, and project control.
- *Sales and marketing* - Trane Company, La Crosse, Wisconsin (1969-1974*).*

Professional Affiliations & Publications

- *Member,* Institute of Management Consultants (Certified Management Consultant since 1981)
- *Member*, Project Management Institute (since 1980).
- *Member,* Keystone National Policy Dialogue on Commercial Nuclear Reactor Decommissioning, Washington DC.
- *Publications:*

  A Survey of Organizational and Contractual Trends in Power Plant Construction, Theodore Barry & Associates, March, 1979.

  Electric Utility Management Development: A Challenge for the 80s, Electric Perspective, Spring, 1981.

  Leverage Leasing: Optimizing the Lessees Decision Making Process, Financial Executive, December, 1981.

  The Changing Dimensions of Utility Human Resources Management, Public Utilities Fortnightly, March 18, 1982.

  The Shifting Standard of Prudence: Implications for Utilities, Public Utilities Fortnightly, October 2, 1987.

  Demand-side Management: Surviving in '90s, Public Utilities Fortnightly, August 1, 1992.

  The Decommissioning Crunch, Energy Magazine, November 1997.

  Challenge of the Millennium, Energy Magazine, June, 1998.

DAVID P. VONDLE, CMC

Managing Consultant

Summary of Qualifications

Mr. Vondle is a managing consultant with the Barrington-Wellesley Group. He has over twenty-five years of experience in assisting clients increase sales, improve quality and service, and reduce costs. Mr. Vondle has served clients in the electric and gas utility, telecommunications, manufacturing, health care, government, and service industries. A partial list of clients served by Mr. Vondle is shown on Exhibit I. He has a special interest in the management of regulated utility distribution enterprises, including electric, gas, telephone and water. Mr. Vondle has testified as an expert witness in eight different jurisdictions.

Mr. Vondle has been designated a Certified Management Consultant (CMC) by the Institute of Management Consultants. He received his M.B.A. from Southern Methodist University and his B.S. in Industrial Management from the University of Akron.

Mr. Vondle is a published author. His book, Service Management Systems: How to Create Competitive Advantages Through Integrated Work Management, Materials Management, Facilities Management, and Cost Management Systems, was published by McGraw-Hill. Mr. Vondle is also a frequent contributor on management topics to periodicals such as Public Utilities Fortnightly, Management Review, SAM Advanced Management Journal, Small Business Reports, and others.

EXHIBIT I

ELECTRIC AND GAS UTILITIES

Allegheny Power System
American Electric Power Service Corporation
Anchorage Municipal Light & Power
ARKLA
Atmos
Atlanta Gas Light Company
BC Gas Utility Ltd.
Boral Energy
Bord Gais Eireann (Irish Gas Board)
Brooklyn Union Gas Company
Canadian Western Natural Gas Co., Ltd.
Carolina Power & Light Company
Centra Gas Manitoba
Central & South West Services, Inc.
Cinergy Corporation
Citizens Gas & Coke Company
Citizens Utilities
Colorado Springs Utilities
Conectiv Solutions
Consolidated Natural Gas Company
Constellation Energy Source
The Consumers Gas Co. Ltd.
Dayton Power & Light Company
Detroit Edison
Enerco New Zealand Ltd.
Florida Power Corporation
Florida Power & Light Company
Gas & Fuel Corporation of Melbourne
Georgia Power
Guam Power Authority
The Hong Kong and China Gas Co., Ltd.
Houston Industries
IES Utilities
Illinois Power Company
Indiana Gas Company
Kentucky Power
KN Energy Incorporated
Los Angeles Department of Water and Power
Louisiana Gas Service Company
MidAmerican Energy
Mountaineer Gas
National Fuel Gas
Nebraska Electric Generation & Transmission
Nebraska Public Power District
New Jersey Natural Gas Company
New York State Electric & Gas
Niagara Mohawk Energy
Northern States Power Company
Northwest Natural Gas Company
Orange & Rockland Utilities
Orlando Utilities Commission
Pacific Gas & Electric
Peoples Gas Light & Coke Company
Peoples Natural Gas Company
Philadelphia Gas Works
Potomac Edison
Public Service Company of New Mexico
Public Service Company of North Carolina
Rochester Gas & Electric
San Diego Gas & Electric
SaskEnergy
South Carolina Electric & Gas
Southern California Gas Company
Southern Connecticut Gas Company
Southern Indiana Gas & Electric Co.—SIGECO
Tacoma Public Utilities
Texas Utilities
Toronto Hydro
Union Gas
United Cities Gas
Utilicorp
Washington Gas Light Company
Washington Water Power Company
West Penn Power

REGULATORY AGENCIES

Alaska Public Utilities Commission
California Public Utilities Commission
Connecticut Department of Public Utilities
Florida Public Service Commission
Georgia Public Service Commission
Guam Public Utilities Commission
Illinois Commerce Commission
Kentucky Public Service Commission
Maryland Public Service Commission
Missouri Public Service Commission
New Jersey Board of Regulatory Comm.
New Mexico Attorney General
New York Public Service Commission
Pennsylvania Public Utilities Commission
Texas Public Utilities Commission
U.S. District Court

Mr. Vondle has accumulated a broad range of experience in his twenty-five years of consulting experience. Examples of this experience are provided below under the following headings:

A. Expert Witness Testimony
B. Management Audits
C. Business Planning, Performance Measurement, Benchmarking, Best Practices, and Balanced Scorecard
D. Process Improvement

A. EXPERT WITNESS TESTIMONY

Mr. Vondle has appeared as an expert witness on utility management topics in the following jurisdictions:

- √ *Alaska Public Utility Commission*—Contel rate case
- √ *California Senate Energy Committee* – California energy crisis
- √ *California Public Utilities Commission* – PG&E
- √ *U.S. District Court*—AT&T anti-trust trial
- √ *Florida Public Service Commission*—setting of contributions-in-aid-of-construction
- √ *Guam Public Utilities Commission*—Guam Power Authority rate case
- √ *New Mexico Public Service Commission*—Public Service Company of New Mexico's acquisition of the Gas Company of New Mexico
- √ *Tennessee Public Service Commission*—United Cities Gas rate case

Mr. Vondle has prepared written testimony for each of the expert witness appearances cited above, as well as:

- √ On behalf of West Penn Power in a Pennsylvania rate case
- √ On behalf of United Cities Gas in Tennessee and Kansas rate cases
- √ On behalf of the Missouri Public Service Commission in a Utilicorp United rate case

Mr. Vondle has also done consulting work in support of, or related to, rate cases in Massachusetts, Colorado, Georgia, Missouri, and New Jersey.

B. MANAGEMENT AUDITS

Mr. Vondle has served as an engagement director, project manager, and/or lead consultant on 27 management audits of electric, gas, telecommunications, and water utilities. Exhibit II presents representative examples of projects completed.

EXHIBIT II

COMPANY	JURISDICTION	PROJECT ROLE	YEAR
Los Angeles Department of Water and Power	City of Los Angeles	• Lead - Workforce Planning, succession planning, management and technical training, gas procurement and business information systems	2002
National Fuel Gas Corporation—Pennsylvania Operations	Pennsylvania Public Utility Commission	• Project Manager • Lead—Gas system planning, design, and construction; gas system operations and maintenance; gas supply; staffing plans and levels	1997
Central Illinois Light Company	Illinois Commerce Commission	• Lead—Organization and work force management; gas system planning, design and construction; operations and maintenance	1995
Peoples Gas Light and Coke Company	Illinois Commerce Commission	• Lead—Use of available technologies, system betterment, maintenance programs, and system mapping and records	1994
Southern California Gas Company	California Public Service Commission	• Team Leader—Distribution operations and measurement	1989

C. BUSINESS PLANNING, PERFORMANCE MEASUREMENT, BENCHMARKING, BEST PRACTICES, AND BALANCED SCORECARD

Mr. Vondle has extensive experience in assisting clients improve business processes and on the related subjects of benchmarking, best practices studies, feasibility studies, and balanced scorecard. Representative examples of these projects are listed below:

BENCHMARKING AND BEST PRACTICES CONSORTIUM

Mr. Vondle initiated, developed, and directed a Utility International Best Practices Consortium. Over its seven years of operation, the Consortium attracted thirty energy utility member participants from seven countries. The Consortium included a balanced scorecard of benchmarked performance measures covering all aspects of company operations and executive conferences that examined innovative best practices from around the world.

BALANCED SCORECARD

Project manager on an engagement to develop a balanced scorecard of key performance indicators for a large Midwestern energy utility. The indicators chosen represent the perspectives of all major stakeholders and are used to guide the business planning process and for self-evaluation.

D. PROCESS IMPROVEMENT

Mr. Vondle has extensive experience in both facilitating employee teams and in leading consultant-driven efforts for a wide variety of business process improvement programs, representative examples of which are presented below:

MAINTENANCE ORGANIZATION AND STAFFING TEAM

Project manager and lead consultant on an engagement to provide guidance and support to a gas transmission and storage compressor station employee team seeking to improve maintenance effectiveness while reducing costs. This study also included conducted a maintenance organization and staffing best practices study of other large oil and gas transmission and storage companies. The project produced practical recommendations to reduce maintenance work, compress equipment down times, decrease overtime and contractor use, and reduce the number of both supervisory and maintenance positions.

CONTRACTING AND CONTRACTOR MANAGEMENT PROCESS REENGINEERING

Lead consultant on a project for a major Midwestern gas distribution company to reengineer the contracting and contractor management processes to reduce costs and exposure to fraud. The project included contractor versus in-house employee decision-making, contractor qualification and selection, project specification writing, compensation policies, contractor quality control and evaluation, and dispute resolution.

CUSTOMER SERVICE REPRESENTATIVE AND SERVICE TECHNICIAN PERFORMANCE IMPROVEMENT TEAMS

Project manager and lead consultant on engagements to analyze and improve the service, quality, and cost performance levels for the customer service representatives and service technicians for a major Midwestern energy utility. The projects involved guiding and assisting a cross-sectional employee team of managers, professionals, supervisors and workers.

Joel F. Jeanson

Senior Associate

Summary of Qualifications

Mr. Jeanson is a Senior Associate of the Barrington-Wellesley Group, Inc. He has extensive experience in public utility finance and accounting, financial and operational auditing, corporate performance, budgeting and management reporting. He has worked in the utility industry since 1979.

Mr. Jeanson received a Bachelor of Science degree in Accounting, with distinction, from Indiana University. He has continued his studies with course work at the Indiana University Graduate School of Business and is also a graduate of the Wabash Executive Program. He is a Certified Public Accountant licensed in Indiana and Wisconsin and is a member of the American Institute of CPAs and the Indiana CPA Society. Mr. Jeanson is a past president of the Indianapolis Chapter of the Institute of Internal Auditors.

During his business career, Mr. Jeanson has directed the accounting, budgeting, corporate performance and auditing departments at a major investor owned gas distribution utility headquartered in Indiana. He began his career with a Big Five public accounting firm.

Utility Consulting Experience

- Lead consultant on project with the largest municipal utility in the United States focusing on the areas of financial management and controls and workforce planning.

- Lead consultant on project for the California Public Service Commission evaluating the effectiveness of energy efficiency programs for two major California investor-owned utilities.

Gas Distribution Utility Experience

- As director of accounting for a major Midwestern gas distribution utility, had responsibility for gas and revenue accounting as well as the general ledger and financial reporting. Issues addressed during this time included margin analysis, unaccounted for gas and the financial impact of weather on earnings. Also responsible for corporate budgeting, including oversight of the development of revenue and throughput budgets.

- As director of corporate performance and financial director of marketing and operations, was responsible for identifying and implementing performance improvement opportunities, primarily focused on marketing and field operations.

- Developed responsibility reporting process, budgets and management reports for Vectren (capital and O&M) for first year post-merger that reflected merger-related costs and savings.

- Financial lead in Vectren merger integration efforts for the various financial areas, including identification of staffing levels and cost savings opportunities and making recommendations to provide structure and direction for the company's financial organization.

- Project director for activity-based management initiative focused on internal products and services. ABM used to assess performance against other service providers, measure performance, and improve decision-making.

- Updated and enhanced monthly financial report used to review actual and projected operating results, and set direction as to action required to meet corporate financial objectives.

- Directed team that established capital expenditure guidelines, policies and procedures for new business capital investments. Introduced discounted cash flow modeling to decision-making process.

- Directed the corporate business planning and budgeting process. Integrated the strategic and operational planning processes so that departmental plans, budgets and performance measures would be focused on both continuous improvement and the accomplishment of corporate objectives – which included both financial and non-financial measures.

- Developed quarterly performance measurement reports that included non-financial as well as financial measures that tracked performance over time and across operating regions as well as against external benchmarks.

- Led customer service business process improvement initiative that assessed performance and made recommendations for improvement of all customer service processes, leading to improved customer service and reduced costs. Facilitated the development of customer service standards.

- Key member of team that completed a study to identify the services, and levels of service, that customers are willing to pay for. This study resulted in significant changes in how the company delivered services to its customers.

- Directed the service technician performance management pilot project to evaluate customer satisfaction and identify cost savings opportunities. This pilot project ultimately led to establishing processes to evaluating operating performance and quality for the entire bargaining unit workforce.

Work Experience

- Senior Associate, Barrington-Wellesley Group (2001 - present)
- Director of Accounting, Budgeting and Management Reporting, Vectren and predecessor companies. (1996 - 2001)
- Director of Corporate Performance, Indiana Gas (1992 - 1996)
- Financial Director of Marketing and Operations, Indiana Gas (1989 - 1992)
- Director of Internal Audit. (1983 - 1989)
- Senior Auditor, Arthur Andersen (1979 – 1983)

Articles and Presentations

- With Gary Gienger, Morris Jacobs, and Glen Martin, "Indiana Energy Gets a Boost from ABC/M", *As Easy As ABC*, Spring 2000.
- "ABC/ABM – A Nucleus of Performance Measurement", Global Business Research Cost Management Congress, November 1994.

CHAPTER IV

PRIOR EXPERIENCE

About the Firm

The Barrington-Wellesley Group, Inc. is a general management consulting firm providing high quality management consulting services to public utilities, regulatory agencies and other professionals serving the public utilities industry. The firm specializes in assisting its regulatory agency clients discharge their oversight responsibilities by performing management and regulatory audits and providing other services to help formulate regulatory policy and test compliance.

Partners in the firm are recognized experts in the public utilities industry. We have a dedicated group of full time employees and augment our capabilities through use of a number of independent consultants with whom we have established relationships. We combine the advantages of large firm expertise needed to successfully perform complex and sensitive assignments with small firm responsiveness, competitiveness and creativity. We have substantial experience in strategic planning, organizational planning and development, corporate performance improvement, management and operational auditing, and litigation support. We have the specialized consulting skills and experience necessary to evaluate all aspects of our client's operations effectively and objectively.

Why Barrington-Wellesley Group?

- *We know the utilities industry.* Through past studies and prior work experience, our consultants have gained a thorough understanding of the utilities business, as well as the nature, strengths, and limitations of utility regulation.
- *We have a reputation for objectivity.* We have a broad management perspective and have worked with clients on a wide range of performance, organizational and management issues. We apply our knowledge of business practices in the utilities and other industries in our search for effective solutions to our client's problems.
- *We seek pragmatic solutions.* Our conclusions and recommendations are tailored to the realities of the client's situation. They are practical, action-oriented, and aimed at improving management effectiveness, operational efficiency and service levels.
- *We have the skills and experience our clients require.* Our professional staff has the diversity of technical training, skills and experience that enables us to serve our clients across a broad range of their business needs. We have successfully performed a large number of utility organization studies and have helped clients implement performance improvement programs in all areas of their management and operations.

Whenever possible, the firm plans and conducts its assignments to maximize client participation. The firm emphasizes team building within the client organization and believes that teamwork in the client-consultant relationship is most effective in finding workable solutions to many problems.

Firm Experience and References

Since its founding in 1990, BWG has performed over thirty independent management and operational audits and regulatory compliance reviews of utility companies for regulatory commissions, governing boards and other clients. Representative assignments completed during the past five years are described in this part of the proposal, including references for some of our most recent assignments.

We selected these projects to demonstrate the firm's broad experience in a wide variety of situations requiring financial verification and testing of regulatory compliance as well as to show the firm's experience in the gas distribution industry. As can be seen, we serve clients in all segments of the public utilities industry across a broad range of subject matter. We are also pleased with the number of repeat assignments we receive from organizations we have worked with in the past and enjoy the continuity of our relationships with many of our clients.

Pacific Gas & Electric (PG&E) -- Financial Condition

BWG performed an audit of the financial condition of PG&E in the midst of the California energy crisis for the California PUC. The audit covered the following topics: credit and default relationships; power purchases and cash flow; cash conservation activities; accounting mechanisms to track stranded cost recovery; intercompany cash flows; and affiliate earnings in the California energy market. [2001]

The complete report BWG's audit of PG&E's Financial Condition can be found on the CPUC's website at: http://www.cpuc.ca.gov/static/industry/electric/electric+issues/pge_sce_audit.htm

Client Reference:

Mr. Kay Kajopaiye
Project Manager
California PUC
505 Van Ness
San Francisco, CA 94102
(415) 703-2557

Philadelphia Gas Works

BWG was engaged by the Pennsylvania Public Utilities Commission (PPUC) to perform a general management audit of this large municipal gas distribution company. Under law, the PPUC assumed regulatory responsibility replacing the City of Philadelphia Gas Commission on July 1, 2000. Audit results cover the full range of operations and are directed at improved

governance, business planning, financial management, and workforce management to improve performance. (2000)

Client References:

Mr. J. Alan Gardocky
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105
(717) 772-0314

Mr. Jim Spadotto
Project Manager Management Audit
Philadelphia Gas Works
800 West Montgomery Ave.
Philadelphia, PA 19122
(215) 684-6609

Southern Connecticut Gas Company (SCG) -- Affiliate Relations

BWG performed a management audit of SCG's affiliate relations for the Connecticut DPUC. The audit focused on SCG's relationships with its affiliates that were providing the utility with customer service systems and off-balance-sheet financing.

Client Reference:

Mr. David Shapiro
Project Manager
Analysis Unit
Conn. Dept. of Public Utility Control
Ten Franklin Square
New Britain, CT 06051
(860) 827-2687

Audit of Atlantic City Electric Company Industry Restructuring Filings

On April 30, 1997, the New Jersey Board of Public Utilities (BPU) published its Findings and Recommendations relating to Restructuring the Electric Power Industry in New Jersey requiring New Jersey electric utilities to prepare unbundled rates, stranded costs, and restructuring plan filings. BWG was retained by the BPU to perform the audit of Atlantic City Electric Company's (ACE) filings.

The purpose of the audit was to determine whether or not the filings were responsive to the Board's and the State of New Jersey's goals with respect to increased competition. These goals include reduced rates, increased customer choice, and maintenance of New Jersey's competitive position in regional, national, and international markets. In addition, the audit determined whether the proposed unbundled rates and restructuring plans provided reasonable

assurance that safe, adequate, and reliable delivery of electric power would continue in the future, when customers have a choice of power suppliers.

Client References:

Mr. Art Gallin
Project Coordinator - Division of Audits
New Jersey Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
(973) 648-4437

Mr. Charles Morgan, Jr.
Project Manager Retail Access
Atlantic City Electric Company
6801 Black Horse Pike
Pleasantville, NJ 08232
(609) 645-4324

Los Angeles County Board of Supervisors
Management Audits of the Parks and Recreation Department
Department of Public Works
Office of County Counsel

BWG has performed a number of general management audits for the Los Angeles County Board of Supervisors. An audit of the Parks and Recreation Department was completed in 2000. Audits of the Department of Public Works and Office of County Counsel were completed in 1999, and 1998, respectively.

Client References:
Mr. Pat McMahon
County of Los Angeles
Chief Audit Division
380 Hall of Records
320 West Temple Street
Los Angeles, CA 90012-3208
(213) 974-0301

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company

With the approval of the California Public Utilities Commission and certain independent energy service providers, BWG was engaged by the three largest California Electric Utilities to perform an audit of the Hourly PX Prices calculated by the companies and used to provide billing credits to customers obtaining electricity from alternative service providers in the deregulated California energy market. Regulatory compliance and price verification audits are being performed for the months of April 1998 through December 2000.

Client References:

Mr. Kayode Kajopaiye, CPA
California Public Utilities Commission
Energy Division
5025 Van Ness Avenue, Room 402
San Francisco, CA 94102
(415) 703-2557

Mr. James A Kelly
Manager of Regulatory Compliance
Southern California Edison Company
2244 Walnut Grove Avenue, Room 312
P.O. Box 800
Rosemead, CA 91770
(818) 302-2284

City of Burbank

BWG was engaged to perform a comprehensive diagnostic management audit of the City's water and electric utilities department for the Burbank City Council. The audit involved an assessment of PSD's competitive position in the emerging deregulated utilities environment, and provided recommendations in all areas of utility management and operations. Subsequently BWG assisted PSD with implementation of audit recommendations and performed a number of follow-up assignments including the quantification of PSD stranded costs (1997).

Client References:

Mr. Ronald V. Stassi
General Manager (Retired)
Burbank Public Service Department
164 West Magnolia Boulevard
Burbank, CA 91503-0631
(818) 238-3550

Mr.Bill Wiggins
Mayor, City of Burbank
275 East Olive Boulevard
Burbank, CA 91502
(818) 238-3550

California Utilities Audit of Transition Cost Balancing Accounts and Headroom Revenues

BWG and Mitchell &Titus, LLP (a certified public accounting firm) were engaged by the California Public Utilities Commission (CPUC) to review the balances transferred to the transition cost balancing accounts and headroom revenues of the three major California electric utilities. This assignment was completed in December 1998 with the issuance of an agreed-upon special procedures report.

Headroom revenues of the utilities are determined residually in accordance with well defined regulatory requirements. Using either revenue requirements or actual rates, amounts related to transmission, distribution, nuclear decommissioning, public purpose programs, fixed transition amount, and Commission-approved obligations such as ISO and PX charges are subtracted from total revenue. Accordingly, this engagement required knowledge of the manner in which the utilities determine PX Credits in the aggregate and for individual rate schedules and

included tests of a statistically valid sample of PX charges and ESP PX credits included on customers' bills.

Client Reference for this project and the two that follow:

Mr. Mark Kent Bumgardner, CPA
California Public Utilities Commission
Energy Division
505 Van Ness Avenue
San Francisco, CA 94102
(415) 703-2887

California Electric Utilities Stranded Cost Filings

BWG and Mitchell & Titus, LLP (a certified public accounting firm) were engaged by the CPUC to review the sunk cost and future competitive transition cost filings of the three major California electric utilities. The specific objectives of the review were to 1) verify and validate the methodology used by the companies to develop their cost estimates; 2) render an audit opinion on the accuracy of reported sunk costs; 3) determine if the future competitive transition costs claimed by each company were allowable under existing legislation or past CPUC decisions; 4) identify any inconsistencies between the companies' filings; 5) identify questioned costs and propose necessary adjustments; and 6) identify key issues for consideration by the Commission.

Key issues in the review included the determination of future costs associated with QF and other purchased power contracts, estimating the costs of contract buy-outs or buy-downs, determining which future plant additions were necessary to keep the plants operating (and recoverable through a non-bypassable customer charge) and which were primarily aimed at making a plant more cost efficient and competitive (and not directly recoverable).

Diablo Canyon Financial Verification Audit

Following the 1997 California Utilities Transition Cost Audit, BWG and Mitchell and Titus, LLP (a certified public accounting firm) were retained to perform a financial verification audit examining the Diablo Canyon nuclear power plant accounts and to express an opinion on the propriety of the financial statements. This financial verification audit evaluated the beginning balances of the Diablo Canyon transition costs included in PG&E's Competitive Transition Cost (CTC) application.

In connection with the performance of the financial audit, the project team also performed an Agreed Upon Procedures Review of Diablo Canyon Sunk Costs. In this review BWG determined the regulatory framework relating to the specific accounting items, performed detailed testing, and identified proposed adjustments or questioned costs. The final project reports were delivered in September 1998.

Connecticut Yankee Atomic Power (CY) - Economic Viability

BWG was retained by legal counsel for the Connecticut DPUC and the Attorney General of Connecticut to develop and provide expert testimony for FERC hearings relating to the economic viability of the early shutdown of the CY plant. (1997)

Client Reference:

Randall L. Speck, Esq.
Kaye, Scholer, Fierman, Hays & Handler, LLP
901 Fifteenth Street NW, Suite 1100
Washington, DC 20005-2327
(202) 682-3510

Connecticut Light & Power (CL&P) - Financial Viability

BWG was retained by the CT DPUC to assess the financial viability of CL&P in light of the extensive outages at the Millstone nuclear units, of which CL&P is the principal owner. The study confirmed that CL&P was in a precarious financial condition, and that the key to resolving the crisis was the timely restart of the Millstone 3 unit. (1998)

Client References:

Mr. Gerald Heffernan
Utility Operations and Management
Analysis Unit
Connecticut Department of Public Utility Control
Ten Franklin Square
New Britain, CT 06051
(860) 827-2623

Mr. Robert V. Ahlstrand
Director, Internal Audit and Security
Department
Northeast Utilities Service Company
Post Office Box 270
Hartford, CT 06141
(860) 665-3584

Piedmont Municipal Power Agency

BWG recently completed a focused review of organizational structure and staffing for the executive management and Board of Directors of this municipal power agency. The study was performed in consideration of changes in PMPA's strategic plans in light of competitive restructuring in South Carolina. [November 2001]

The report for this project is confidential.

Client Reference:

Mr. Don Ouchley
General Manager
Piedmont Municipal Power Agency
121 Village Drive
Greer, SC 29651
(864) 877-9632

SBC/Ameritech Merger Investigation

BWG recently completed an investigation of the merger of SBC Communications and Ameritech Corporation for the Illinois Commerce Commission. The engagement involves testing of compliance with the provisions of the Commission's merger order and the verification and quantification of savings attributable to Illinois operations of the company. (Current)

The report for Phase I of this assignment can be found on the Illinois Commerce Commission's website at: http://www.icc.state.il.us/icc/tc/doc.asp#sbc

Client References:

Ms. Judith R. Marshall, CPA
Illinois Commerce Commission
Telecommunications Division
527 East Capitol Avenue
Springfield, Illinois 62794
(217) 524-5070

Mr. Marvin Tilton
Executive Director – Transition Planning
SBC Communications, Inc.
1758 E. Houston Street
San Antonio, TX 78205
(210) 551-5087

BWG Management and Operational Audits

BWG has performed the following audits of utilities for regulators since it's founding in 1990:

- Philadelphia Gas Works – Comprehensive -- Pa PUC (2001)
- Pacific Gas & Electric - Financial Condition -- California PUC (2001)
- Southern Connecticut Gas - Affiliate Relations -- Connecticut DPUC (2000)
- Peoples Natural Gas - Comprehensive -- Pennsylvania PUC (1994)
- New Jersey Natural Gas - Comprehensive -- New Jersey BRC (1993)
- Delta Natural Gas - Comprehensive -- Kentucky PSC (1992)
- SBC/Ameritech - Cost Allocations and Merger Savings -- Illinois Commerce Commission (2001)
- California Electric Utilities - PX Prices -- California PUC (2001)
- Nevada Power - Power Systems -- Nevada PSC (1994 and 1999)
- Department of Public Works - Comprehensive -- LA Board of Supervisors (1999)
- Connecticut Light & Power - Financial Viability -- Connecticut DPUC (1998)
- California Electric Utilities - Transition Cost Balancing Account -- California PUC (1998)
- Pacific Gas & Electric - Diablo Canyon Financial Verification - California PUC (1998)
- Atlantic City Electric - Industry Restructuring Filings -- New Jersey BPU (1998)
- Maine Yankee Atomic Power - Prudence -- Maine PUC (1997)
- California Electric Utilities-Stranded Cost Filings -- California PUC (1997)
- Connecticut Yankee Atomic Power - Economic Viability -- Connecticut DPUC and Connecticut Attorney General (1997)
- Northeast Utilities - Nuclear Operations -- Connecticut DPUC (1996)
- Connecticut Light & Power-Diagnostic -- Connecticut DPUC (1996)
- Burbank (CA) Public Service Department - Comprehensive -- City Council (1996)
- Mountain Water District - Comprehensive -- Kentucky PSC (1996)
- Pacific Bell - Customer Service -- California PUC (1995)
- US West - Affiliate Transactions -- Oregon, Washington, Idaho and Minnesota Commissions (1995)
- Pacific Gas & Electric - Pipeline Expansion -- California PUC (1995)
- Los Angeles Department of Water and Power - Diagnostic -- LA City Council (1994)
- Pacific Gas & Electric - Demand-Side Management -- California PUC (1994)
- Southern California Water - Comprehensive -- California PUC (1994)
- Southern California Edison - Research, Development & Demonstration -- CPUC (1993)

CHAPTER V

BUDGET AND TIME ESTIMATES

Cost and Price Analysis

BWG estimates professional fees for providing the requested consulting services at $48,500. We have estimated project expenses at 18% of professional fees, or $8,730 for a total not-to-exceed cost of $57,230. Exhibit V-1 provides a breakdown of the hours and professional fees estimated for each phase of work by individual consultant.

Exhibit V-1
Estimated Hours and Costs By Task and Individual

CONSULTANT	Laros	Vondle	Jeanson	Total Hours	Total Fees
PROJECT RESPONSIBILITY	Engagement Director / Testimony	Lead Consultant / Testimony	Lead Analyst		
Staffing Level	Managing Director	Managing Consultant	Senior Associate		
Rate Per Hour	$225	$175	$150		
1 – Planning / Work Prioritization	5	10	15	30	$5,125
2 – Investigation and Analysis	10	60	80	150	$24,750
3 – Written Testimony	15	20	20	55	$9,875
4 – Oral Testimony / Other Assistance	20	20	5	45	$8,750
Total Hours	50	110	120	280	
Total Fees By Individual	$11,250	$19,250	$18,000		$48,500

BWG's cost estimates incorporate the following assumptions:

- Work begins June 17, 2002 and is completed by October 8, 2002.
- The above billing rates incorporate a discount for government/non-profit organizations of approximately 13% below standard BWG billing rates.
- The final allocation of hours and resources to the requested work tasks will be determined in consultation with the NDPSC staff based on Commission priorities. BWG will only charge for time actually incurred on behalf of the client. BWG will not exceed the total estimated cost without prior NDPSC approval.
- Our quotation includes a separate estimate for travel and other project related expenses at 18% of professional fees. Based on our past experience, this is a realistic estimate of these costs for projects of this nature, giving the above

average travel costs associated with getting to Bismarck North Dakota. BWG only charges for expenses at actual cost, without any markup. BWG will comply with any NDPSC restrictions on travel expenses and expense reporting.

- Costs for additional work tasks (if any are deemed required by the NDPSC) will be estimated at the above hourly rates and presented to the Commission for approval prior to proceeding with any proposed work. BWG is prepared to participate, subsequent to the technical hearing, as a witness in additional hearings before the Commission, at the same hourly rates shown in Exhibit V-1.
- BWG agrees that this contract can be terminated at any time. BWG would expect to be given reasonable time to wind down its activities and, if appropriate, to document the work and results for future use.

Proposed Billing Methodology

Invoices will be submitted to the project manager monthly with required supporting documentation by the 10th day of the following month. Billings will be based upon actual hours expended and actual expenses incurred. Following approval of the monthly invoices, payments will be due from the NDPSC within 20 working days of their receipt of the approved invoices.

Our invoices will show the hours incurred by each individual assigned to the project and their hourly rates. Travel and other costs directly attributable to the project will be billed at cost. All invoices will be in sufficient detail to enable the project manager to identify the work completed and the corresponding charges.

CHAPTER VI

CONFLICTS OF INTERESTS AND COMPLIANCE WITH APPLICABLE AMERICANS WITH DISABILITIES ACT OF 1991 AND EEO LAWS AND REGULATIONS

Conflicts of Interest

Neither the Barrington-Wellesley Group, Inc. nor any of its employees have now or in the past had any relationship with Montana-Dakota Utilities or any company affiliated with the MDU Resources Group, Inc. In connection with our work, we regularly perform studies for other utilities and regulatory agencies, and sometimes testify in connection with these assignments. To the best of our knowledge, we currently have no assignments that would create potential conflicts of interest on this engagement. All of our current assignments and those completed within the past five years that might be of interest to the Commission are disclosed in Chapter III – Prior Experience or in the individual resumes provided in Chapter IV of the proposal.

During the course of the review, BWG and its employees will be in compliance with our internal policies concerning conflict of interest on management reviews of utilities. These policies include the following:

A. No Solicitation or Acceptance of Gifts or Favors

Neither BWG nor any of its employees or subcontractors will solicit or accept anything of value to the recipient, including a gift, loan, reward, meal, promise of future employment, favor, or service from employees or representatives of any of the entity being audited.

B. No Conflicting Employment or Contractual Relationship

Neither BWG nor any of its employees will have or acquire any employment or contractual relationship with the audited firm during the course of this audit. BWG and its subcontractors will not perform subsequent work for MDU Resources Group or affiliates for a period of two years following the completion of the review without the prior approval of the Commission.

C. No Disclosure or Use of Proprietary Information

Neither BWG nor any of its employees will disclose or use any proprietary information concerning operations of the utility that was gained by reason of our position on the review and which is not available to the general public, for corporate or personal gain or benefit, or for the gain or benefit of any other business entity or person unless we are otherwise instructed by the Commission.

D. No Financial Positions in MDU Resources Group

Neither BWG, and to the best of our knowledge do any of our proposed project team members, currently hold or have intentions to acquire any interest (financial or otherwise) in MDU Resources Group or any of its affiliated companies.

Compliance

BWG currently complies and will continue to comply with all applicable Equal Employment Opportunity laws and regulations and with the applicable provisions of the Americans with Disabilities Act of 1991.

Michael A. Laros
Barrington-Wellesley Group, Inc.
Managing Director

SNAVELY KING MAJOROS O'CONNOR & LEE, INC.
ECONOMIC AND MANAGEMENT CONSULTANTS

May 28, 2002

Mike Diller, Director of Accounting
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, ND 58505-0480

Dear Mr. Diller

Enclosed herewith are three signed copies of the proposal of Snavely King Majoros O'Connor & Lee, Inc. to the North Dakota Public Service Commission in response to your request for proposal, dated May 10, 2002, for consulting assistance in connection with the Commission Staff's investigation of Montana-Dakota Utilities Co's gas rate increase request, Case No. PU-399-02-183.

I would be happy to respond to any questions or comments you may have concerning this proposal.

Thank you very much for this opportunity to submit our proposal.

Sincerely,

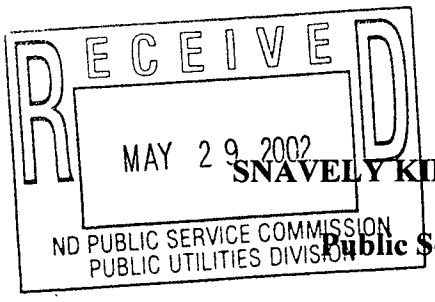
Charles W. King
President

1220 L STREET, NW, SUITE 410, WASHINGTON, DC 20005-(202)371-1111, FAX (202)842-4966

1471 CASTILLO DELMAR, CAROLINA, PR 00979-(809)783-7683, FAX(809)783-7559

by Snavely King Majoros O'Connor & Lee, Inc.

05/29/2002 CC: Comm Legal Illona, Pat, Jerry Mike .



Proposal by
SNAVELY KING MAJOROS O'CONNOR & LEE, INC
to the
Public Service Commission of North Dakota
Case No. PU-399-02-183

Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King") is pleased to respond to the May 10, 2002 Request for Proposal ("RFP") from the Public Utilities Commission of North Dakota ("PSC") for expert witness consulting assistance in connection with Case No PU-399-02-183, involving Montana-Dakota Utilities' ("MDU") rates for natural gas.

I. The Firm

Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 10 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before Federal and State regulatory agencies. Over the course of its 32-year history, members of the firm have participated in over 500 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

II. Objective

The objective of the work contemplated in this proposal is to develop the Commission Staff's position on five issues pertaining to MDU's request for an increase in its gas rates: (1) the appropriate level of investment, (2) the appropriate cost of capital, (3) the appropriate cost of service, (4), the appropriate rate design, and (5) appropriate depreciation rates. For purposes of this proposal, issues (1) and (3) will be consolidated into the single issue of "revenue requirement"

III. Issues

A. Revenue Requirement

As noted in the attachment to the RFP, 80 percent of MDU's gas revenues are spent on the procurement of gas. As a consequence, the projection of weather-normalized sales takes on a high degree of importance in this proceeding, as does MDU's gas procurement practices. For the past five years Snavely King has participated on behalf of the D.C. Office of People's Counsel in the Gas Procurement Working Group convened by the District of Columbia Public Service Commission to examine the gas purchasing practices of the Washington Gas Light Company. We are therefore familiar with the procedures used to weather-normalize gas consumption and the pricing and contractual practices associated with the procurement of gas, gas transportation and gas storage.

There are a number of additional revenue requirements issues that were raised in MDU's electric case, Case No. PU-399-01-186, and resolved in favor of the Commission staff. These included office expenses, administrative salaries, and the Supplemental Security Income Plan. Presumably, the Company has recognized the Commission's findings with respect to these items and will not seek recovery of them again. However, it will be necessary to examine all expenditures, capital and operating, to ensure that they are fully justified by the need to serve the Company's North Dakota retail customers.

B. Cost of Capital

The Commission's decision in Case No. PU-399-01-186 also resolves many of the controversies that have arisen with resect to MDU's cost of capital, including the capital structure, the cost of debt, and the selection of comparable companies for purposes of implementing the Discounted Cash Flow procedure for estimating equity return. We expect that the rate of return to equity for MDU's gas service to be somewhat lower than the 11.8 percent found appropriate for MDU's electric service.

That is because gas distribution service is generally considered by investors to be less risky than electric service.

C. Rate Design

Gas rate designs are generally quite simple, consisting of a customer charge and a commodity charge, with the latter sometimes having a declining block structure. Gas companies prefer to increase the customer charges because they are not susceptible to the vagaries of weather, nor do they suffer attrition when customers install more fuel efficient appliances. The objection to high customer charges, particularly for residential customers, is that they cannot be mitigated by conservation, thereby diluting the benefit from improving insulation and installing more efficient furnaces.

Snavely King will defer to the Staff on the issue of whether to support a weather-normalization adjustment. There are benefits to both the Company and consumers from such an adjustment because it tends to reduce bills in unusually cold winters, even though it increases them in warmer winters. Furthermore, there is a cost of capital effect resulting from the reduction in risk to the Company's earnings stream. On the other hand, customers may react negatively to rate adjustments that are not transparent, and that appears to result from a "black box" calculation they can neither duplicate nor understand.

D. Depreciation

Snavely King is widely recognized as one of the nation's leading analysts of utility depreciation on behalf of consumer interests. Its experience goes back to the 1970s, when Snavely King acted as consulting experts to a number of state commissions and consumer advocates in the tri-annual represcriptions of depreciation rates conducted by the FCC Accounting and Audits Division. Generally, Snavely King reviews, evaluates and restates depreciation rate studies submitted by the utilities.

However, the firm has the capability to conduct a *de novo* depreciation study if it can be given access to the utility's plant records.

We confidently predict that a major depreciation issue will be cost of removal. Typically, gas utilities mark up the original cost of distribution mains for purposes of depreciation by 40 to 60 percent and customer services by 60 to 100 percent. The presumed objective of this mark-up is to account for the expected future cost of removing these facilities. Snavely King has successfully attacked this practice (most recently in Georgia[1]), and it is now subject to further challenge under the prescriptions of Financial Accounting Standard 143, *Accounting for Asset Retirement Obligations.* Removal or modification of these very large removal cost mark-ups will significantly reduce the depreciation rates for MDU's gas distribution facilities.

IV. Staffing

Charles W. King, President of Snavely King, will be the overall project director. He will also serve as the expert witness on cost of capital, gas procurement practices, weather normalization, and rate design. Michael J. Majoros, Jr., Vice President, will direct the review of MDU's accounting and depreciation presentations and will provide expert witness testimony on these issues. These two principals will be assisted by Snavely King's support staff, consisting of Margaret Kenney, Kajal Kapur, David Geisler and Caridad Garcia. Resumes of Messrs. King and Majoros are attached to this proposal.

V. Work Plan

The work tasks required for this project are those conventionally associated with rate cases, as follows:

- Review the Company's initial filing,

[1] See Order, Georgia P.S.C. Docket No. 14311-U, *Earning Review of the Atlanta Gas Light Company,* April 29, 2002.

- Prepare initial data requests,
- Evaluate the responses to the data requests and determine the availability of data to support the analysis of the issues,
- Evaluate and analyze each issue, quantitatively wherever possible,
- Prepare direct testimony,
- Respond to data requests on the prefiled testimony,
- Review and evaluate the Company's rebuttal testimony,
- Prepare data requests on the rebuttal testimony,
- Prepare surrebuttal testimony,
- Attend hearing in Bismarck, and
- Assist counsel on brief.

It is possible that some of these tasks will not be permitted under the Commission's procedures. For example, commissions do not always allow Staff to submit surrebuttal testimony. Our experience in North Dakota, however, is that such testimony is permitted, whether in prefiled form or live on the witness stand. Additionally, the "common" budget allows three days for the hearing. Our experience is that North Dakota P.S.C. hearings do not necessarily require that much time.

The attached schedule sets forth the estimated workhours of company principals and support staff for each task, subdivided by subject area. Note that separate workhour estimates are provided for "depreciation review," where the Company submits a depreciation study, and "depreciation study," where Snavely King conducts a depreciation study directly from the Company's plant records. There is a separate category called "common" covering attendance at the hearing, and it is assumed that the workhours presented would be the same regardless of the mix of assignments. The one exception would be if the Commission were to assign only one subject area, in which case the common workhours would be halved because only on Snavely King principal, not two, would attend the hearing.

VI. Budget

The attached schedule presents the fee and expense budget for each of four subject areas, with the depreciation phase shown under two scenarios, "depreciation review" if the Company submits a depreciation study, and "depreciation study" if Snavely King conducts the depreciation study from the Company's plant records. The "common" category reflects the need to send two witnesses from Washington, DC to Bismarck. As noted, if only one subject area is assigned, the fees, as well as the travel-related expenses, would be halved.

The subject area budgets are developed in isolation, that is, they reflect the assumption that only that subject would be assigned. Since there is some synergy among the subject areas, Snavely King proposes that the aggregate fee budget be reduced by 10 percent for each additional subject added. For example, if the Commission were to assign revenue requirements and cost of capital, the overall budget would be as follows:

Revenue Requirements	$19,340
Rate of Return	11,400
Common	3,840
Total Fees	$34,580
Less 10%	(3,458)
Total Fees Adjusted	$31,122
Expenses	2,880
Final Budget	$34,002

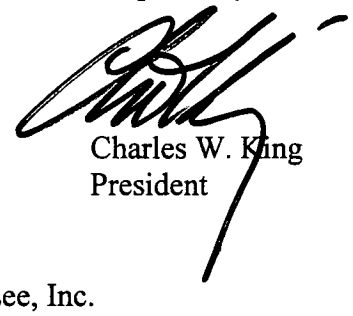
If all four subject areas were assigned, including the review of a MDU depreciation study, the budget would be as follows:

Revenue Requirements	$19,340
Rate of Return	11,400
Rate Design	7,760
Depreciation Review	22,880
Common	3,840
Total Fees	$65,220
Less 30%	(19,566)
Expenses	2,880
Final Budget	$48,534

VI. Conclusion

We believe the foregoing information responds fully to the RFP. However, we would be happy to respond to any questions or comments the Commission Staff may have concerning our firm, its staff or this proposal. Snavely King appreciates this opportunity to submit its proposal to the North Dakota Public Service Commission.

Respectfully Submitted,



Charles W. King
President

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Snavely King Majoros O'Connor & Lee, Inc.
MDU Gas Rate Case
Project Budget

Workhours:

	Task	Revenue Requirement			Cost of Capital			Rate Design			Depreciation Review			Depreciation Study			Common
		Principals	Staff	Total	Principals	Staff	Total	Principals	Staff	Total	Principals	Staff	Total	Principals	Staff	Total	Prinicipals
1	Review Company Filing	8		8	5		5	3		3	12		12				
2	Prepare Initial Data Requests	10		10	3		3	2		2	8		8	12		12	
3	Evaluate Responses/Data Availability	8		8	5		5	3		3	10		10	25	30	55	
4	Conduct Evaluation/Analyses	40	35	75	15	25	40	15	20	35	35	40	75	80	100	180	
5	Prepare Direct Testimony	25	15	40	15	15	30	12		12	30	40	70	30	40	70	
6	Respond to Data Requests	8			5			3			10			10			
7	Review/Evaluate Rebuttal	10		10	8		8	3		3	15		15	15		15	
8	Prepare Data Requests on Rebuttal	3		3	2		2	2		2	5		5	5		5	
9	Prepare Surrebuttal	15		15	12		12	8		8	8	12	20	8	12	20	
10	Attend Hearing																32
11	Assist Counsel on Brief	5		5	2		2	2		2	4		4	4		4	
	Total Workhours	132	50	174	72	40	107	53	20	70	137	92	219	189	182	361	32
	Rate Per Hour	$ 120	$ 70		$ 120	$ 70		$ 120	$ 70		$ 120	$ 70		$ 120	$ 70		$ 120
	Fees	$ 15,840	$ 3,500	**$ 19,340**	$ 8,640	$ 2,800	**$ 11,440**	$ 6,360	$ 1,400	**$ 7,760**	$ 16,440	$ 6,440	**$ 22,880**	$ 22,680	$ 12,740	**$ 35,420**	**$ 3,840**

Expenses		
Air Fare	2 persons Washington DC - Bismarck @ $950	$ 1,900
Hotel & Meals	2 persons, 2 nights @ $120/night	480
Local Travel	2 days car rental @ $55/day	110
Airport Parking	2 persons 3days @ $15/day	90
Reproduction		100
Delivery and Postage		200
Total Expenses		**$ 2,880**

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water and sewerage companies. Mr. Majoros has appeared before Federal and state agencies. His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros also provides consultation to the U.S. Department of Justice.

Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. He has also developed the firm's capabilities in the management audit area.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros performed various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company). In addition, he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM80-42.

Handling Equipment Sales Company, Inc., *Treasurer (1976-1978)*

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business. During this period Mr. Majoros worked consistently on a part-time basis in the following positions: **Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Noron & Wrgod, CPA's, Credit Clerk – Montgomery Wards.**

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Med-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

Charles W. King

Experience

Snavely King Majoros O'Connor & Lee, Inc.
Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, earnings and depreciation. Mr. King recently directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc.
Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc.,
Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

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