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 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., for Authority to Establish Increased Rates for Natural Gas Service	)))))	Case No. PU-399-02-____

* * * *

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.

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. 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
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
Burleigh County, North Dakota
My Commission Expires: 02/16/06

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. 1

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Date Filed: April 12, 2002 **Effective Date:**

Issued By: Donald R. Ball
Director of 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

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

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. 3

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.:**

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

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

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. 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:	$.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.

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. 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:

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.

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

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.

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. 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	$.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.

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

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.

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

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.

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

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.

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. 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	$.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).

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.

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	Minimum
	$1.003 per dk	$.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:

(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.

(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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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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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.

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.

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.

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

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 (60ºF). 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.

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.

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 N 4th Street
Bismarck, ND 58501

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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 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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Gas Rate Schedule

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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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.

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.

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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	Public Utility Bonds 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			Retention	Retention
	EPS	DPS	ROE	Rate	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%

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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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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?

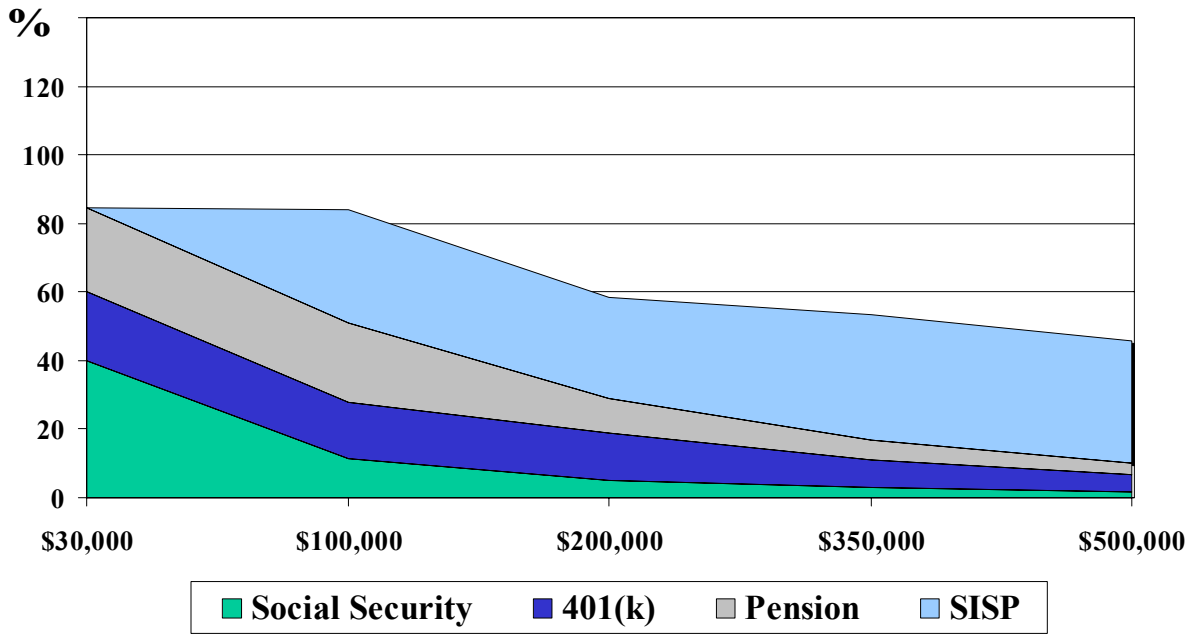
A. Yes, they should be. The SISP is a common type of benefit provided in today's business environment. The combined replacement

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**
		Small Meter	Small Meter	Large Meter
	Annual Usage (Dk)	110	300	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.

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	Dk	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			
Interruptible	24	1,014,790	2,448,094			
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%

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 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 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.
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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.

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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

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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.