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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

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 served on several committees of the Electric Power Research Institute and the Edison Electric Institute.

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 explain the Company's position regarding the North Dakota Public Service Commission Staff's (Staff) recommendation for an electric rate decrease and to introduce the other witnesses who will sponsor testimony on behalf of Montana-Dakota.

Q. What is the Company's position with respect to the Staff recommendation?

A. It is our position that Montana-Dakota's current electric rates are just and reasonable and should not be reduced at this time. My testimony, along with that of other witnesses, will show that no rate reduction is warranted at this time. The Staff case does not take into account a number of necessary adjustments in making an appropriate determination regarding the reasonableness of the existing electric rates. Our testimony will address the necessary adjustments.

Q. When was the last electric general rate change for Montana-Dakota?

A. Montana-Dakota's electric rates were last changed in February 1987.

Q. Would you please explain how Montana-Dakota has been able to hold its electric rates flat since 1987?

A. From 1987 to 2001 the consumer price index has risen 59%. In spite of this significant increase, we have been able to hold our electric rates flat for this entire period by finding ways of operating our business more efficiently and taking advantage of new technologies where it makes economic sense to do so, while maintaining a consistent focus on providing safe, reliable electric service to our over 70,000 electric customers in North Dakota at reasonable and competitive prices. Let me give you a few examples of what we did.

- ✓ We implemented a new Customer Information System to streamline our billing and record keeping processes to operate more efficiently and keep costs down.
- ✓ We implemented a computerized dispatching system that saves about an hour a day of a service person's time by having a computer in the service vehicle with the day's work orders which enables us to directly dispatch orders electronically. This results in efficiencies and less paper work. An hour a day of an employee's time translates to a significant benefit and we expect to improve on this in the future.
- ✓ We have implemented a customer service center where all calls for service related matters come into a central location, saving time and personnel requirements. The centralized call center also allows employees to handle multiple subject matters with customers and allows us to tie into the computerized dispatching system for faster and better customer service.
- ✓ We continue to participate in joint trenching with others to minimize the cost of extending our lines to new customers.
- ✓ We have combined our gas meter testing into one facility that handles our testing program on a company-wide basis. This allows for more specialized testing equipment, increasing meter testing throughput.
- ✓ Implemented itron meter reading system, which loads the read data directly into our customer records without manual key punching.

- ✓ We are using joint meter reading with others to minimize costs. Currently we read the water meters for the cities of Richardton and Wildrose for a fee and we are looking for other opportunities to reduce the costs for our customers in this area.
- ✓ We are currently developing a geographic information system (GIS) where all of our maps will be converted to electronic format. This will provide easier and quicker updating of system changes, and improved access to the information by all users, resulting in time saving and other efficiencies.

In addition to the above, we also continue to look for other opportunities to reduce costs and increase efficiencies.

Q. Has Montana-Dakota earned its authorized return level in each of the years since 1987?

A. No, it has not. In the years since 1987 our earnings have sometimes been below the authorized level set by the Commission and sometimes above that level. A regulated utility, on average and over time, should be able to earn at or near its authorized return level. I should note that we did not seek a rate increase in those years in which our earnings fell short of reaching the authorized level set by the Commission. Our efforts to achieve efficiencies have been beneficial to our customers and our shareholders by providing rate stability in an increasing cost environment while providing adequate returns to attract investment, maintaining a financially viable utility and providing the necessary service.

Q. Is a regulated public utility such as Montana-Dakota guaranteed a reasonable return on the investment it has made in facilities to provide safe and reliable electric service?

A. No. A regulated public utility is only afforded an opportunity to earn a reasonable return on its investment in facilities dedicated to public utility service. There is no guarantee.

Q. Did the earned returns for the period 1997 through 2000 exceed the authorized return level?

A. Yes, they did.

Q. Would you explain the reason for the return levels in these years?

A. Yes. The earned return levels for this period were caused primarily by a single element, the selling of power in the wholesale market as the opportunities arose. It was a market anomaly that afforded us, and other utilities across the country, the ability to temporarily obtain significantly increased revenues and margins from sales of electric energy into the wholesale market in the last few years. I should note that, had we only been able to make these sales at the historic levels, the Company would have earned less than its authorized return, holding all other things constant. This is shown graphically on Exhibit No. ___ (CWF-1).

Q. Do those same opportunities currently exist in the wholesale market?

A. No. Those opportunities, we believe, peaked in 2001 and will be significantly reduced in the current year (2002) and beyond. The reasons for the loss of opportunities are described in the testimony of Mr. Blinsky,

Montana-Dakota's Electric Bulk Power Marketing Coordinator. In short, the opportunities to obtain higher prices for wholesale power no longer exist in the current market.

Q. What does this mean for Montana-Dakota?

A. What this means for Montana-Dakota is that we will no longer be able to sell as much power in the wholesale market and what we do sell will not be at the higher prices we have seen in the past few years. This translates to a significant downturn in our earnings. The ability to make wholesale sales at higher prices was the primary reason that we exceeded our authorized return for the period in question. Absent these market opportunities, our returns will be significantly reduced. The effect of this on our earnings will be quantified by other witnesses.

Q. Are there factors other than the lack of wholesale sales opportunities that lead you to conclude that no electric rate reduction is appropriate at this time?

A. Yes, there are. In addition to the wholesale sales levels, there are a number of other changes in cost levels from the year 2000 basis used by the Staff that the Commission needs to take into consideration in determining the reasonableness of our electric rates. These known and measurable changes will be discussed in detail by other witnesses.

Q. Would you please summarize the Company's position?

A. The current rates for the North Dakota electric operation, given the changes described for the wholesale electric market, the other known and measurable changes and the current capital costs described by Montana-

Dakota's witnesses, are just and reasonable and in the public interest. In fact, as shown on Ms. Mulkern's exhibit, there is a revenue deficiency of $710,000. When we also consider the added costs expected in the near future for the new turbine described by Mr. Gress, it would make no sense whatsoever, in my view, to reduce rates now only to raise them in the very near future.

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. Terry L. Blinsky, Electric Bulk Power Marketing Coordinator for Montana-Dakota, will testify regarding the wholesale power market and the appropriate level of wholesale sales given current conditions in the wholesale market. Mr. Gerald L. Gress, Power Production Manager for Montana-Dakota, will testify regarding required additional generation related expenditures. Mr. Donald R. Ball, Director of Regulatory Affairs for Montana-Dakota, will testify regarding certain known and measurable adjustments. Ms. Rita A. Mulkern, Regulatory Analysis Manager for Montana-Dakota, will testify regarding the total revenue requirements necessary for Montana-Dakota's North Dakota electric operations.

Q. Does this complete your testimony?

A. Yes, it does.

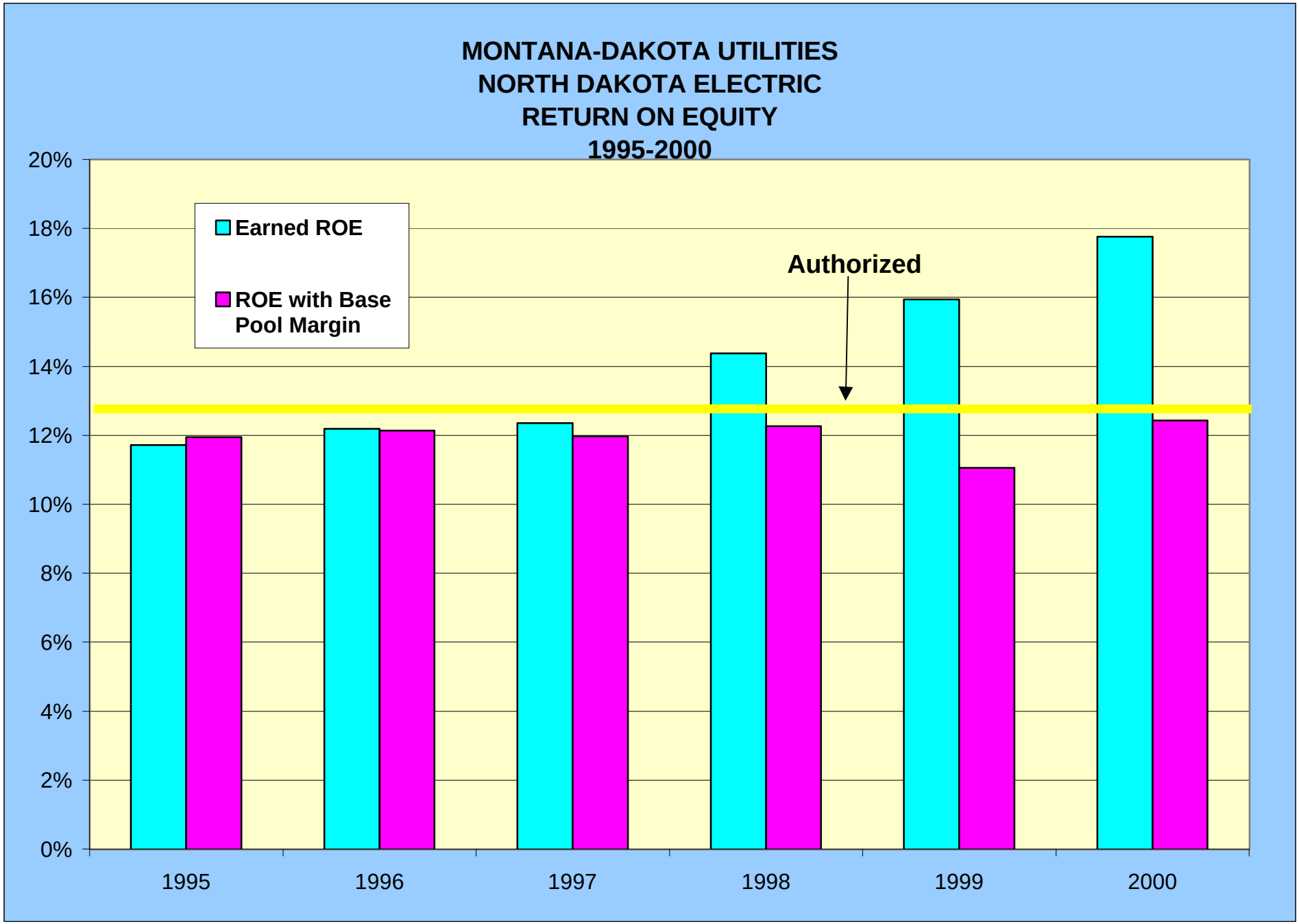
MONTANA-DAKOTA UTILITIES
NORTH DAKOTA ELECTRIC
RETURN ON EQUITY
1995-2000
20%
18%
16%
14%
12%
10%
8%
6%
4%
2%
0%
Earned ROE
ROE with Base Pool Margin
Authorized
1995
1996
1997
1998
1999
2000

Exhibit No.___(JSG-1)

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

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

DOCKET NO. PU-399-01-186

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 course. 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. This proceeding arises out of a complaint that was filed by the Staff of the North Dakota Public Service Commission ("PSC"). In this complaint, the PSC Staff contends that the Montana-Dakota Utilities Co. ("Montana-Dakota") electric generation, transmission and distribution operations in the state of North Dakota are collecting excess revenues of approximately $9.155 million. I have been asked by Montana-Dakota to evaluate the required overall rate of return for the company's electric distribution operations in the state of North Dakota and to evaluate the rate of return study filed by Charles W. King on behalf of the Staff of the North Dakota PSC on August 31, 2001.

Q4. Would you please summarize your testimony?

A. Mr. King has recommended that Montana-Dakota be allowed a return on common equity of only 11.2 percent and an overall rate of return on rate base of 9.67 percent. However, a review of Mr. King's cost of capital study reveals that he has excluded several of the most relevant proxy companies from his return on equity study and used a proxy group of companies that is inappropriate for estimating the rate of return for the Montana-Dakota electric operations. In addition, the allowed rate of return for a regulated public utility requires a flotation cost adjustment in order to meet the standard that the return is sufficient to attract capital on reasonable terms. By excluding such an adjustment Mr. King's recommendation falls short of

the return that investors require to invest in Montana-Dakota's North Dakota electric operations. In this Direct Testimony, I calculate the cost of common equity capital for Montana-Dakota's electric operations based on a Discounted Cash Flow ("DCF") analysis of a group of companies that are more nearly similar to Montana-Dakota's electric 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.

In addition, Mr. King has incorrectly calculated the cost of debt. My Direct testimony presents the correct calculation of these values and discusses the precedents for the calculation methods used by Montana-Dakota.

Q5. What rate of return is Montana-Dakota requesting in this proceeding?

A. Based on its test period capital structure, as shown in the testimony of Mr. King, Montana-Dakota is requesting the following rate of return:

Source	Amount (000s)	Percent	Cost	Overall Rate of Return
Long-Term Debt	$144,894.0	45.90%	9.22%	4.23%
Preferred Stock	$16,500.0	5.23%	4.63%	0.24%
Common Equity	$154,250.0	48.87%	12.75%	6.23%
TOTAL	$315,644.0	100.00%		10.70%

As my testimony discusses, an overall allowed rate of return of 10.70 percent, with a 12.75 percent return on common equity, represents the cost of capital for Montana-Dakota.

Company Background

Q6. 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, distributes natural gas in southeastern North Dakota and western Minnesota.

In 2000, Montana-Dakota served a total of 115,000 residential, commercial and industrial customers. As shown on Exhibit No. ___ (JSG-2), Schedule 4, page 1, Montana-Dakota's electric utility assets comprised 13.2 percent of MDU Resources' total assets. In addition, the electric utility revenues and operating income accounted for 8.6 percent and 17.9 percent of MDU Resources' total, respectively. North Dakota accounted for 60 percent of the electric utility operating revenues, while Montana (23 percent), South Dakota (7 percent) and Wyoming (10 percent) accounted for the other 40 percent of electric utility revenues.

Most of Montana-Dakota's generation is derived from four coal-fired steam turbine generating stations. In addition, it has three combustion turbine

peaking stations. The total generating capacity owned by the company is approximately 400 Mw.

II. FINANCIAL MARKET STUDIES

Criteria for a Fair Rate of Return

Q7. 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.

Q8. 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.

Q9. 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.

Q10. 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

Q11. In estimating the cost of capital for Montana-Dakota in this proceeding, Mr. King has added together the interest rate plus the non-cash issuance cost amortization and divided that sum by the net unamortized balance of the debt issues. Is this the appropriate method for estimating the cost of debt for ratemaking purposes?

A. No. Mr. King's accounting-based approach understates the effective cost of debt. In addition, Mr. King is wrong in asserting that the FERC requires his approach for ratemaking. Instead, although for *accounting* purposes the FERC typically requires a straight-line amortization of issuance costs to allocate debt

issuance costs to each year that the debt is outstanding, the FERC requires a yield-to-maturity approach for estimating the cost of debt for *ratemaking* purposes.

Q12. Would you please describe the correct method for calculating debt costs?

A. The correct method for calculating total debt costs is to use the "Yield-to-Maturity" method (which may also be referred to as the Internal Rate of Return ("IRR") method) that Montana-Dakota used in its Data Response No. 9 to Mr. King's Data Request dated July 19, 2001. This data response, which shows Montana-Dakota's calculation of cost for each of its long-term debt issues, is included as an attachment to Mr. King's testimony. A summary of the costs for each debt issue is shown on Exhibit No. ___(JSG-2), Schedule 1. By calculating the effective cost of debt based on the actual amounts and the actual timing of cash flows, the "Yield-to-Maturity" method provides an accurate calculation of the true cost of each debt issue.

Q13. Why is Mr. King's accounting-based approach inaccurate?

A. There are three major problems with Mr. King's accounting-based approach:

1. It incorrectly assumes that interest is paid only at the end of each year when, in fact, it is paid semi-annually.

2. For purposes of estimating <u>the amount of funds available</u> to the issuer, Mr. King's approach incorrectly assumes that the issuer does not pay issuance expenses, discount expenses, and associated losses on redemption of debt until the final year when the principal is repaid. However, those expenses are paid at the time the debt is issued and therefore reduce the net proceeds available to the issuer.

3. For purposes of estimating <u>the timing of cash payments</u> for issuance expenses, discount expenses and associated losses on redemption of debt, Mr. King's approach incorrectly assumes that the issuer does not make these cash

payments until the years in which an amortization expense is recorded in the accounting records. However, those expenses actually are paid at the time the debt is issued and therefore generally occur long before any of the non-cash, annual amortization entries are recorded for accounting purposes.

Each of these flaws causes Mr. King's accounting-based approach to understate the cost of long-term debt.

Q14. At page 7, line 26 to page 8, line 4 of his testimony, Mr. King cites the Federal Energy Commission's accounting and reporting requirements for "Long-Term Debt: Premium, Discount and Expense, and Gain or Loss on Reacquisition" as the reason that he thinks Montana-Dakota has calculated debt cost incorrectly. This citation also provides the basis for his calculation of debt costs. Has he cited the correct section of the FERC's regulations for electric companies?

A. No. Mr. King has mistakenly relied upon accounting rules that appear in Subchapter C, Part 101 ("Uniform System of Accounts Under the Federal Power Act"), of the FERC's rules and regulations. Those accounting rules do not prescribe or require any calculation of the effective annual percentage cost of debt. Instead, the pertinent FERC rules for calculating debt costs for ratemaking purposes appear in Subchapter B, Part 35 ("Filing of Rate Schedules"). Therein, at §35.13 (h), (22), (ii), (B), (6) the FERC prescribes the following method for calculating the cost of debt for ratemaking purposes:

> *"Cost of Money, which is the* ***yield to maturity at issuance based on the interest rate and net proceeds to the utility*** *determined by reference to any generally accepted table of bond yields."* (Emphasis added).

In other words, for ratemaking purposes, the FERC requires utilities to calculate the cost of debt using the method employed by Montana-Dakota.

Q15. Do you disagree with other aspects of Mr. King's debt cost calculation?

A. Yes. The commitment fees on lines of credit are a relevant cost given the components of the capital structure that Mr. King has chosen to include. Consequently, the cost of commitment fees is included in the debt cost calculation in Schedule 1 of Exhibit No. ___(JSG-2).

Q16. 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 on page 2 of Schedule 1. For purposes of this proceeding, Montana-Dakota accepts the debt components and capital structure proposed by Mr. King. However, as I have shown, Mr. King has incorrectly calculated the cost of the debt. Schedule 1, page 1 of Exhibit No. ___(JSG-2), shows that the correct calculation of overall average debt costs for Montana-Dakota results in a cost of 9.22 percent.

Q17. What cost of preferred stock did you use?

A. Montana-Dakota's annual cost of preferred stock is 4.632 percent.

Interest Rates and the Economy

Q18. 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 2 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 3.2 percent for the past ten years. However, in recent months the economy has been shrinking and is in a recession. A significant decline in stock market prices in recent months is partially the result of an increase in the perceived risk of equity investments at this time.

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 3.0 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 2.3 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 2 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

Q19. 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.

Q20. 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 + .5g). 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

Q21. 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 5 of Exhibit No. ___(JSG-2) shows a representative sample of flotation costs incurred with 15 new common stock issues by electric companies between 1996 and 2000. Flotation costs associated with these new issues averaged 4.62 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 Electric Utility Companies

Q22. 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 electric operation as a stand-alone company is not possible. To get around this problem, I have used a proxy group of companies that is most nearly similar in risk to the regulated electric utility operations of Montana-Dakota. Consequently, like Mr. King, my estimate of the rate of return which investors require for Montana-Dakota is primarily determined by conducting market-based DCF analyses of a group of publicly-traded electric utility proxy companies with a range of risks that includes

risks that are comparable to the risks of Montana-Dakota's operations. These analyses of a group that includes comparable companies suggest the level of returns that is appropriate for Montana-Dakota's North Dakota electric operations.

Q23. How did you begin the process of selecting your group of proxy companies?

A. I started with the two lists of companies examined by Mr. King. In his testimony, Mr. King presents two groups of companies that he analyzed separately for purposes of setting an allowed rate of return for Montana-Dakota's North Dakota electric utility operations.

First, he presented a list of vertically-integrated companies engaged in electric generation, transmission and distribution operations that also meet two criteria: (i) they have investment-grade bond ratings; and, (ii) they have total revenues in excess of $100 million. From this list, he chose companies that derived at least 85 percent of their revenues from electric operations.

Mr. King also selected a second list of Combination companies with investment-grade bond ratings and revenues in excess of $100 million that are engaged in both electric and gas distribution operations. For this group of companies, he selected those that had combined electric and natural gas revenues that made up at least 85 percent of their total revenues. In other words, a majority of the companies in this second group derived less than 85 percent of their revenues from electric operations, and several of Mr. King's Combination companies even derived less than 75 percent of their revenues from electric operations. Nevertheless, because they also were engaged in natural gas distribution operations, he included them in a group of proxy companies.

Q24. Which of his two groups of proxy companies formed the basis for Mr. King's recommended rate of return for Montana-Dakota's electric operations?

A. Because, according to his DCF analyses, the Combination companies selected by Mr. King had a lower average required rate of return (11.2 percent) than the electric-only companies (12.0 percent), Mr. King concluded that there were significant differences in risks between combination companies and electric-only companies.

Based on this first conclusion, Mr. King next concluded that, since Montana-Dakota has natural gas distribution operations as well as electric operations, the allowed rate of return for its electric operations should be less than the rate of return indicated by his study of electric-only companies.

As a result of these two unsupported conclusions, Mr. King decided to ignore the electric-only group of companies in estimating the required rate of return for Montana-Dakota's electric operations. Instead, he advocates the use of the results of his study of Combination companies and recommends an allowed return on common equity of 11.2 percent.

Q25. Do you agree with Mr. King's method of selecting companies that are supposedly comparable in risk to Montana-Dakota's North Dakota electric operations?

A. No. For purposes of setting an allowed rate of return for electric operations, the appropriate proxy group is one that is primarily engaged in electric operations. Mr. King's reason for rejecting the use of electric-only companies is incorrect and unsupportable for several reasons. First, his conclusion that a

significant difference in risk exists between the Combination companies and the electric-only companies is incorrect. Therefore, his basis for rejecting the use of electric-only companies in setting a rate of return for electric operations is unsupportable. Second, Mr. King's choice of proxy companies is based primarily on the fact that MDU Resources also owns natural gas distribution operations. However, that fact should be irrelevant to this proceeding. The allowed rate of return for Montana-Dakota's electric operations should reflect the risk of those operations on a stand-alone basis. Third, it is inherently illogical to *reject* companies like Southern Company and Kansas City Power & Light which derive 98 and 95 percent of their revenues from electric operations, and replace them with companies like Alliant Energy and Energy East which each derive 68 percent of their revenues from electric operations.

Q26. Would you please elaborate on why Mr. King is incorrect in asserting that a distinction should be made between electric-only companies and Combination electric and gas companies?

A. In addition to the common logic of including electric-only companies in the sample group, there is a simple test for determining whether a statistically significant difference exists between two sample groups. Mr. King has concluded that because the average rate of return results are different for the two groups in his analysis, there must be a fundamental difference in risk between the two groups. However, the simple fact that there is a difference in the average for the two groups does not, by itself, suggest that the two groups have fundamentally different characteristics. Virtually any two groups that are selected are bound to have different average

returns as a result of essentially random effects on the various companies in each group. A valid, simple statistical test considers three factors:

1) Whether a difference in the averages exists;
2) The magnitude of the difference in the averages; and,
3) The variation in the returns for the two sample groups.

Mr. King has considered only the first of these three factors and has ignored the second and third factors. For example, close examination of the variance of returns in the two groups shown in Table 7 of page 18 of Mr. King's testimony suggests substantial overlap between the two groups. FPL Group, one of the supposedly "high risk" electric-only companies has a lower return than several of Mr. King's supposedly "low-risk" combination companies. Similarly, some of the companies in the supposedly "low-risk" combination company group have returns that are as high as, or higher than the returns of any of the supposedly "high-risk" electric companies.

Q27. Would you please describe the analysis that you performed to determine whether Mr. King's DCF results lead to the conclusion that there is a statistically-significant difference between the electric companies and the combination companies that he analyzed?

A. I have applied a common statistical test to determine whether a statistically significant difference exists between Mr. King's two groups of companies. This test incorporates all three of the factors discussed above in order to generate a probability that the averages for the two groups are sufficiently different so as to allow a conclusion that the difference in averages is statistically significant. It is common to

set a probability of five percent or less as the cutoff for accepting an hypothesis. In other words, a statistically-significant difference generally would require that there be a confidence level of 95 percent or more that the difference in means is greater than zero. However, as shown on Exhibit No. ___ (JSG-2), Schedule 3, Mr. King's DCF results indicate a probability of at least 11.7 percent that there is no difference in the average returns for the two groups of companies. Since the 11.7 percent level of significance exceeds the five percent cutoff, the difference in the average returns estimated by Mr. King for the two groups is not statistically-significant. Instead, there is a reasonable probability that the difference in means is the result of random variations in the outcomes for the two groups.

Q28. If Mr. King's DCF results do not indicate a statistically-significant difference in means, is it valid to exclude the electric-only companies from consideration in setting the allowed rate of return for Montana-Dakota's electric operations?

A. No. As I have shown, Mr. King's stated reason for assuming that the combination companies have lower risk than the electric companies cannot be supported conclusively. More important, however, is the fact that the most appropriate group for estimating the return for Montana-Dakota's electric operations is a group that is selected based on the fact that a large percentage of its revenues, assets or operating income are associated with electric operations.

Q29. If there were a statistically-significant difference in average DCF results between the electric and combination companies used by Mr. King, would that fact be a sufficient reason for excluding electric companies and using combination companies instead?

A. No. The purpose of this proceeding is to establish rates for Montana-Dakota's electric operations. However, Mr. King decided to use combination companies and exclude electric-only companies because Montana-Dakota is engaged in both electric and natural gas operations. He asserts that companies engaged in both lines of business have lower risks and that combination companies should be used because:

> "*As a heating source, electricity and gas are to great extent competitors. When a company offers only electric service, it faces the competition of a gas utility and the consequent uncertainties as to market penetration. But when it offers both gas and electricity, it has a reasonable guarantee that regardless of changes in heating technology or consumer preference, it will control the most of the market for heating fuels. Its business risk is therefore lower. For this reason, the most comparable group of utilities to MDU is the combination electric and gas companies.*" (Direct Testimony of Charles W. King, page 23, lines 3-9).

Mr. King's analysis is flawed in several respects. Although electric and gas may compete for some heating load, the primary uses of these two forms of energy are fundamentally different. Montana-Dakota's natural gas distribution system is primarily used to provide heat and is not used to provide lighting or to run appliances such as televisions, computers, dishwashers, etc. Similarly, its electric system is not primarily used to heat homes, offices and schools and essentially has significant heating load only in those small communities and rural areas where natural gas is not available. The differences in the primary uses of the two forms of

energy is sufficiently great that the level of direct competition is a minor part of both operations. Therefore, although some degree of inter-energy competition exists between gas and electricity, such competition is very minor, especially for electric operations.

Much more importantly, to the extent that inter-energy competition exists, a company does not reduce the risk of investing in electric facilities merely by owning natural gas distribution operations. When given a choice of heating sources people will choose between gas and electricity based on the relative economics of each energy source. In the long run, Montana Dakota has very little ability to control the relative level of fuel costs and the cost and efficiency of heating appliances that use the different energy sources. Thus, Montana Dakota is limited in its ability to induce people to select one heating source over another. Montana-Dakota's investments in electric facilities would face the same level of risk regardless of whether Montana-Dakota also owned natural gas distribution operations.

While Mr. King is undoubtedly correct in assuming that a diversified parent company can face less risk than each of its subsidiary operations individually, he is wrong in suggesting that such parent-company diversification reduces the risk of investing in any individual operation. For example, if there is a sudden change in the market that causes people to convert large amounts of load from electricity use and switch to natural gas, the value of Montana-Dakota's electric operations would be impaired regardless of who owns the natural gas distribution system. The same would be true for any electric or combination company.

Thus, even if it could be shown that combination companies face less risk than electric-only companies, that fact would not suggest that the electric operations of diversified combination companies face less risk than the electric operations of electric-only companies.

Q30. How did you select a proxy group that adequately reflects the risks of Montana Dakota's electric operations?

A. I started by combining Mr. King's two groups of companies. According to Mr. King, these companies were selected by him in part because they still have vertically-integrated electric generation, transmission and distribution operations. I then selected all companies that derived at least 75 percent of their revenues from electric operations. Unlike Mr. King, I included companies that derive large amounts of revenue from electric operations, but do not have natural gas distribution operations. In addition, unlike Mr. King, I excluded companies that had less than 75 percent of their revenues associated with electric operations, even if they also had natural gas distribution revenues. The goal was to select *all* companies on the list that derived at least 75 percent of their revenues from regulated electric operations. Both Mr. King and myself excluded Empire District Electric because analysts' forecasts of growth for that company were not available. As shown on page 1 of Exhibit No. ___ (JSG-2), Schedule 3, there are 12 companies that fit the required criteria. It should be noted that Kansas City Power & Light, one of Mr. King's companies, recently formed a holding company and changed the name of the publicly-traded company to Great Plains Energy, Inc. Consequently, Great Plains

Energy in my exhibits is essentially the same as Kansas City Power & Light in Mr. King's exhibits.

Q31. How did you calculate the dividend yields for the companies in your comparison group?

A. These calculations are shown on page 3 of Schedule 4 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 June 2001 to November 2001. 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.

Q32. 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

Q33. 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.

Q34. 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 4, page 5, the average of the analysts' long-term growth rate estimates for the electric utility proxy companies is 7.0 percent.

Q35. 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).

Q36. 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.

Q37. 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 4 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 6.0 percent.

Q38. 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 3 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.[1] The average of the weighted average growth rates for the proxy companies is 6.7 percent and the median is 6.9 percent.

Q39. 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 4 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 4 of Exhibit No.___(JSG-2). This Second-Stage Retention Growth DCF analysis indicates that the cost of common equity capital for the electric utility proxy companies is in a range between 10.2 percent and 15.4 percent. The median for the group is **12.6 percent**.

[1] 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).

Basic DCF Analysis

Q40. 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.

Q41. How did you calculate the cost of capital using the Basic DCF analysis?

A. These calculations are shown on page 7 of Schedule 4 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 **13.1 percent**.

Primary DCF Analysis

Q42. 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.

Q43. 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 2 of Exhibit No.___(JSG-2) shows that the United States Gross Domestic Product has grown at an average annual rate of 7.8 percent during the past 30 years. During the past decade U.S. GDP growth has averaged 5.6 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 6.3 percent over the long-term.

Another factor will be growth in demand for electricity and related energy products. The U.S. Department of Energy forecasts that electricity output will increase at an annual rate of 1.7 percent during the next 20 years. Increasing amounts of generation, transmission and distribution facilities should be needed to achieve this growth.

In my opinion, investors reasonably expect the 12 companies in this comparison group to grow at a rate that is somewhere in the range of 6.25 percent to 7.25 percent. Based on the median and average growth rates of approximately 7.0 percent currently projected by investment analysts, as well as the 6.3 percent growth rate in the economy, increasing demands for electricity, 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.

Q44. What does your primary DCF analysis indicate with regard to investors' current market rate of return requirements?

A. Page 8 of Schedule 4 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 electric utility proxy companies that is developed on page 3 of Schedule 4. This market-based primary DCF analysis indicates that the cost of capital for the proxy companies is approximately in the range of **12.2 percent** to **13.3 percent**.

Risk Premium Analyses

Q45. 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 electric operations have been 1,210 basis points (12.1 percent) above the yields on long-term government bonds. As shown on page 1 of Schedule 4 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 12.1 percent premium for companies in Montana-Dakota's size range suggests a required return of 17.6 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 1,170 basis points (11.7 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 19.1 percent.

Alternative Equity Investment Analysis

Q46. 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 electric utility 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.

Q47. 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 2 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 1999. It can be seen, in fact, that average returns for the S&P 500 companies have been 20.69 percent for the past five years. For purposes of comparison with allowed returns for regulated electric utility 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%**

Q48. Is it appropriate to set the allowed rate of return for an electric utility 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 electric utility 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. Thus, investors would expect that on average they will actually earn something less than the allowed amount. Electric utility 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 electric utility 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 20.69

percent. As this comparison indicates, an allowed return of 12.75 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 electric operations to successfully compete for capital.

Relative Risk Analysis

Q49. Have you compared the risks faced by Montana-Dakota's North Dakota electric 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.

Q50. Would you please describe the business risks inherent in the electric 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 electric utility 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.

One of the current sources of risk and uncertainty include the possibility of open-access transmission and customer choice programs that could introduce

widespread competition for electric generating customers. Because a large portion of the costs of electric generation are long-lived, fixed costs, there is a possibility that competitive electric generation markets could result in excess capacity that could take many years to subside. In any competitive market characterized by excess capacity there will be a tendency for prices to reflect short-run marginal costs. In other words, competitive prices could be so low that companies would be unable to recover all, or a portion of the sunk, fixed costs of their generating plants.

The business model of Montana-Dakota and other major utilities is based on the fact that traditionally electricity has been provided most efficiently by large, centralized generating plants connected to the market with extensive networks of transmission and distribution lines. However, in the future, demand for Montana-Dakota's electric services could be affected by the adoption of distributed generation technologies that allow customers to generate their own power instead of relying on utility generation, transmission or distribution. The overall efficiency of these technologies has improved significantly in recent years and some electricity consumers have begun installing and using distributed generation equipment. Shifts in the overall cost of distributed generation relative to the fuel and network costs of centralized utility generation could imperil the ability of some utilities to recover the investments they have made under the traditional "public utility model" of electricity supply.

In addition, the constantly-changing mandates of environmental laws disproportionately impact electric utilities, especially coal-burning utilities.

Litigation expenses and exposure to tort claims also is an increasingly important consideration for electric utility investors.

Q51. What are some of the business risks faced by Montana-Dakota's North Dakota electric operations?

A. These operations face many of the same risks that are associated with other electric utilities. However, Montana-Dakota faces three risks that distinguish it from many other utilities.

First, nearly all of its generation is from a single fuel source: coal. Utilities that are heavily weighted toward one fuel source face greater risks that adverse circumstances will arise that render all of their generating capacity uneconomic. Montana-Dakota's customers have benefited greatly from the company's use of low-cost coal, but there is an element of risk associated with this undiversified generating mix. For example, during the past decade there have been repeated discussions of the possibility that carbon dioxide emissions might be severely limited. If restrictions on carbon dioxide were to be enacted, coal-fired generation would be disproportionately impacted. Similarly, if prices for natural gas were to decline significantly, Montana-Dakota could find that its generating mix is uneconomic. In fact, most new generation constructed in recent years has been fueled with natural gas as a result of low gas prices and new, efficient generating technologies.

Second, as shown on Exhibit No. ___ (JSG-2), Schedule 4, page 1, Montana-Dakota's electric utility 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 electric utility assets are equal to only 4.8 percent of the assets of the median proxy company. Similarly, Montana-Dakota's electric operating revenues and operating income are only 4.5 percent and 6.6 percent of the level for the median proxy company. Thus, depending upon the measure of size, the typical proxy company is somewhere between 15 and 22 times the size of Montana-Dakota's electric utility operations.

This smaller size has significant implications for business risks. As noted earlier, 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 electric utility operations are heavily dependent upon a relatively undiversified local economy. Factors that negatively influence the local economy can reduce demand for Montana-Dakota's electric 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.

Third, Montana-Dakota faces direct competition for new and existing load and is at a disadvantage in this competition. For example, much of the load growth in North Dakota is occurring in the larger cities. However, the larger cities served by Montana-Dakota in North Dakota are essentially ringed by rural electric cooperatives ("REC's"). Under the North Dakota Territorial Integrity Act, REC's are given control over service in the areas that they serve, even when a city annexes territory as the city grows. Consequently, as the cities served by

Montana-Dakota grow geographically, Montana-Dakota generally is unable to grow along with its larger cities. Since the smaller towns served by Montana-Dakota are generally losing population, there are few opportunities to offset this loss of population in smaller towns with growth in the larger cities. This disadvantage in attracting new load in North Dakota places Montana-Dakota at risk that its facilities will become underutilized and that it will be unable to recover its costs.

The existence of adjacent and surrounding electric cooperatives also means that Montana-Dakota faces competitive threats to its existing load. For example, in August 2001, Watford City, North Dakota held a referendum on whether to condemn Montana-Dakota's electric distribution facilities and contract with McKinsey Electric Cooperative for electric service. If this referendum had passed, generation and transmission facilities of Montana-Dakota might have been stranded.

With its undiversified generating sources, small size, limited growth opportunities and competitive threats and disadvantages, Montana-Dakota's North Dakota electric operations face greater overall business risk than the typical company in the electric utility proxy group.

Q52. 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 an electric utility 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 electric 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. In fact, after the experiences of the 1980s, investors are concerned with the risks associated with after-the-fact prudence reviews and possible regulatory cost disallowances. In addition, investors are aware that ill-conceived regulatory restrictions associated with electric utility restructuring in California played a decisive role in causing Pacific Gas & Electric Company into bankruptcy and massive losses at Southern California Edison Company.

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 electric 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 electric utility industry.

Value Line rates the regulatory climate in North Dakota as being "average." However, in 1997 the North Dakota legislature established an Electric Industry Competition Committee to study over a six-year period the impact of

competition on the electric utility industry in North Dakota. With the possibility of restructuring in the next several years, there must be some uncertainty in the minds of investors regarding the regulatory rules that will be applied to Montana-Dakota in the event that restructuring occurs. This uncertainty increases the perceived risk associated with Montana-Dakota's existing and future investments in its electric utility operations.

Q53. 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 4 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. The median bond ratings for companies in the proxy group are A- for Standard & Poor's and A2 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 equal to or slightly

lower 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 4 shows that Montana-Dakota's filed common equity ratio, 48.7 percent, is near the high end of the range for the proxy companies. This higher common equity ratio suggests lower financial risk that serves to offset the higher business risk faced by Montana-Dakota's North Dakota electric utility operations.

Q54. 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 electric utility comparison group.

Q55. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's electric operations?

A. Montana-Dakota faces overall risks that are about average relative to those of the proxy companies. Montana-Dakota has above-average business risks due to its lack of diversified generation sources, its exceptionally small size relative to the proxy companies, and its competitive disadvantages. The fact that these higher business risks are offset by lower financial risks suggests that Montana-Dakota's electric operations are average relative to those of the proxy companies. 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 electric utility operations are about average relative to the risks of the proxy companies.

III. SUMMARY AND CONCLUSIONS

Q56. Would you please summarize the results of your cost of capital study?

A. Yes. I conducted several DCF analyses on a group of electric utility 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		
Electric Utility Proxies:		
- Second-Stage Retention Growth	12.03%	12.60%
- Basic DCF	12.49%	13.09%
- Primary DCF	12.16%	12.73%
Benchmark Analyses		
Risk Premium Return Based On:		
- U.S. Treasury Bonds		
v. Large Companies	13.3	
v. Small Companies	17.6	
- Corporate Bonds		
v. Large Companies	14.8	
v. Small Companies	19.1	
Alternative Investments		
- S&P 500	20.7	
- Value Line Industrials	29.4	

My second-stage retention growth analysis indicates a median cost of common equity capital of 12.6 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 range of 10.1 percent to 16.1 percent and a median required rate of return of 13.1 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 electric utility comparison companies to achieve during a long period of time in the future. This primary DCF analysis indicates that the cost of capital for electric utility companies with risks comparable to those of Montana-Dakota is in a range between 12.2 percent and 13.3 percent. The mid-point of this range is approximately 12.75 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 20.7 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.

Q57. 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 electric utility operations at this time would be **12.75 percent**. This recommended return reflects my assessment that Montana-Dakota's overall risks are about average relative to the proxy group. A return of 12.75 percent is very near the middle of the range for my Primary DCF analysis and is very close to the median for my Second-Stage Retention Growth analysis. It is also somewhat below the median return calculated using a basic DCF analysis.

Q58. Does this conclude your Prepared Direct Testimony?

A. Yes.

MONTANA-DAKOTA UTILITIES CO.

CAPITAL STRUCTURE - DEBT
12/31/2000

DEBT	BALANCE OUTSTANDING	ANNUAL COST	ADJUSTED EMBEDDED COST
LONG-TERM DEBT CAPITAL	$132,850,000	$11,874,562	8.938%
AMORTIZATION OF LOSS ON BOND REDEMPTION *		548,429	
LONG-TERM NOTE PAYABLE	243,971	19,226	7.880%
TERM LOAN	1,300,000	124,475	9.575%
COMMERCIAL PAPER	10,500,000	693,000	6.600%
COMMITMENT FEES ON LINES OF CREDIT		102,544	
TOTAL DEBT	**$144,893,971**	**$13,362,236**	**9.222%**

* Debt was fully retired May 1998 and no new debt was issued to replace it; cost amortized over original life of issue.

Sources: Exhibit No. ___(JSG-2), Schedule 1, page 2; Testimony of Charles W. King, Schedule 1; Montana-Dakota.

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2000

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

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money	Principal Outstanding	Annual Cost	Embedded Cost
First Mortgage Bonds:						
Secured Medium-term Notes, Series A:						
8.25%	$26,111,796	87.039%	10.177%	$30,000,000	$3,053,100	
8.6%	28,906,532	82.590%	11.020%	35,000,000	3,857,000	
6.52%	14,082,923	93.886%	7.811%	15,000,000	1,171,650	
6.71%	13,488,404	89.923%	8.195%	15,000,000	1,229,250	
5.83%	14,813,914	98.759%	6.086%	15,000,000	912,900	
Pollution Control Refunding Revenue Bonds:						
Mercer County 6.65%	14,061,276	93.742%	7.288%	15,000,000	1,093,200	
Richland County 6.65%	3,063,677	94.267%	7.243%	3,250,000	235,398	
Morton County 6.65%	2,420,986	93.115%	7.344%	2,600,000	190,944	
Total First Mortgage Bonds	116,949,508			130,850,000	11,743,442	8.975%
Pollution Control Notes:						
Grant County 6.2% *	5,427,042	96.911%	6.556%	2,000,000	131,120	6.556%
Total Long-Term Debt Capital	$122,376,550			$132,850,000	$11,874,562	**8.938%**

* Reflects 2001-2003 average as shown on Direct Testimony of Charles W. King, Schedule 1.

Sources: Montana-Dakota Response to Data Request No. 2 Dated June 18, 2001.

Montana-Dakota Utilities Co.

General Economic Statistics

1970-2000

Year	Percentage Price Changes: Consumer Price Index	Percentage Price Changes: GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP (Billions)
1970	5.7%	5.3%	0.2%	1,039.7
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%	2.0%	4.4%	8,318.4
1998	1.6%	1.2%	4.4%	8,790.2
1999	2.2%	1.5%	4.2%	9,299.2
2000	3.4%	2.1%	5.0%	9,965.7
Average Rate of Change: 1/				
1970-2000	5.2%	4.5%	3.2%	7.8%
1980-2000	4.2%	3.5%	3.1%	6.6%
1990-2000	3.0%	2.3%	3.2%	5.6%

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

Source: *Economic Report of the President* , February 2001.

Montana-Dakota Utilities Co.

Moody's Bond Yield Averages
December 1999 - November 2001

		Average Corporate	Public Utility Bonds A-Rated	Public Utility Bonds Baa-Rated
1999	DEC	7.87	8.14	8.28
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

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
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	

Source: Standard & Poor's Analyst Handbook, 2000.

Mr. King's Electric Companies That Derive 75% of Revenue from Regulated Electric Service

King Co.	Company Name	Total Revenue	Regulated Electric Revenue	Regulated Gas Revenue	% of Revenue from Electric Operations
	Empire District Electric Co	260	259		99.6%
E	**Southern Company**	10,066	9,860		98.0%
E	**Kansas City Power & Light**	1,116	1,064		95.3%
C	**Sierra Pacific**	2,334	2,219	101	95.1%
E	**Pinnacle West**	3,690	3,480		94.3%
C	**Ameren**	3,856	3,526	324	91.4%
E	**FPL Group**	7,082	6,361		89.8%
C	**Progress Energy**	4,119	3,565	324	86.6%
	IDACORP (Idaho Power)	1,019	836		82.0%
C	**Puget Sound Energy**	3,442	2,772	612	80.5%
	American Electric Power	13,694	10,827		79.1%
C	**DPL Inc (Dayton Power & Ligh**	1,437	1,090	184	75.9%
	Cleco Corp	821	620		75.5%
	Hawaiian Electric Co Inc	1,719	1,277		74.3%
	DTE Energy	5,597	4,129		73.8%
C	Consolidated Edison Inc.	9,431	6,938	1,262	73.6%
	Entergy Corp	10,016	7,220	166	72.1%
C	Alliant Energy	2,405	1,648	415	68.5%
C	Energy East	2,960	2,024	772	68.4%
\	Madison Gas & Electric	324	203	121	62.7%
	Allegheny Energy	4,012	2,507	*	62.5%
	TECO Enregy (Tampa Elec Co	2,295	1,354	314	59.0%
	Xcel Energy (No. States Power)	11,592	6,492	1,466	56.0%
	PPL Electric Utilities Corp	5,683	3,167	*	55.7%
	Wisconsin Electric Power (Wisc	3,355	1,798	736	53.6% #
	Constellation Energy Group	3,878	2,052	502	52.9%
	Rochester Gas & Electric	1,448	731	340	50.5%
	Dominion Resources (Va. Powe	9,260	4,492	1,374	48.5%
	Portland Gen Elec Co (Enron)	2,253	1,044		46.3%
	Oklahoma Gas & Electric	3,299	1,454		44.1%
	SCANA Corp (Pub Ser or NC,S	3,433	1,334	998	38.9%
	WPS	1,951	625	265	32.0%
	Cinergy Corp.	8,421	2,692	429	32.0%
	Sempra Energy	7,143	2,184	3,305	30.6%
	NI Source	6,031	1,557	1,807	25.8%
	TXU Corp	22,009	4,752	962	21.6%
	Vectren Corp	1,649	336	819	20.4%
	Reliant Energy	29,339	5,494	*	18.7%
	Black Hills Corp	1,624	173		10.7%
	Duke Enrgy	49,318	4,946		10.0%
	UGI Corp (UGI Utilities)	1,762	78	359	4.4%
	Utilicorp	28,975	1,208	826	4.2%
	NorthWestern Corp	7,132	87	95	1.2%
	MDU Resources Group	1,874	162	233	8.6%

* Companies that did not report electric and gas revenues separately.
Proportion of "electric" revenues is actually electric and gas revenues.

From SEC Form 10-K.

Montana-Dakota Utilities Co.

Statistical Comparison of Difference
Between Mr. King's Two DCF Sample Results

Electric Utilities		Electric and Gas Utilities	
Company	DCF Return	Company	DCF Return
FPL Group	11.2	Alliant Energy	8.9
Kansas City P&L	12.9	Ameren	11.1
Pinnacle West	12.4	Consolidated Edison	9.6
Southern Company	11.7	DPL	13.4
		Energy East	11.1
		Progress Energy	12.2
		Puget Sound Energy	12.9
		Sierra Pacific	10.4

t-Test: Two-Sample Assuming Unequal Variances

	Electric	*Electric and Gas*
Mean	12.05	11.2
Variance	0.5633	2.4629
Observations	4	8
Hypothesized Mean Difference	0	
df	10	
t Stat	1.2690	
P(T<=t) one-tail	**11.66%**	
t Critical one-tail	1.8125	
P(T<=t) two-tail	23.32%	
t Critical two-tail	2.2281	

t-Test: Two-Sample Assuming Equal Variances

	Electric	*Electric and Gas*
Mean	12.05	11.2
Variance	0.5633	2.4629
Observations	4	8
Pooled Variance	1.893	
Hypothesized Mean Difference	0	
df	10	
t Stat	1.0089	
P(T<=t) one-tail	**16.84%**	
t Critical one-tail	1.8125	
P(T<=t) two-tail	33.68%	
t Critical two-tail	2.2281	

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
December 31, 2000 Operating Data

	Assets ($000,000)	Operating Revenues ($000,000)	Operating Income ($000,000)
Ameren	$9,714	$3,855	$942
American Electric Power	$54,548	$13,694	$2,229
Cleco Corp	$1,846	$820	$147
DPL Inc	$4,436	$1,437	$445
FPL Group	$15,300	$7,082	$1,307
IDACORP (Idaho Power)	$4,639	$1,019	$353
Great Plains Energy	$3,294	$1,116	$292
Pinnacle West	$7,149	$3,690	$676
Progress Energy	$20,091	$4,119	$1,087
Puget Sound Energy	$5,557	$3,442	$493
Sierra Pacific	$5,639	$2,334	$97
Southern Company	$31,362	$10,066	$2,404
High	$54,548	$13,694	$2,404
Median	**$6,394**	**$3,566**	**$585**
Low	$1,846	$820	$97
Montana-Dakota Electric Utility	**$305**	**$162**	**$39**
MDU Resources Group, Inc.	$2,313	$1,873	$217
Montana-Dakota Electric Util. % of:			
- Proxy Company Median	**4.8%**	**4.5%**	**6.6%**
- MDU Resources Group, Inc.	13.2%	8.6%	17.9%

Sources: Zacks.com and *Market Guide* on America Online; MDU Annual Report and 10-K.

Montana-Dakota Utilities Co.

Bond Ratings of
Selected Electric Utility Proxy Companies

	Standard & Poor's	Moody's
Ameren	A+	Aa2
American Electric Power	A-	A3
Cleco Corp	BBB+	A2
DPL Inc	BBB+	A2
FPL Group	A	Aa3
IDACORP (Idaho Power)	AA-	A2
Great Plains Energy	A	A1
Pinnacle West	A-	A3
Progress Energy	BBB+	A1
Puget Energy	BBB	Baa1
Sierra Pacific	A-	A3
Southern Company	A+	A1
Median	A-	A2
MDU Resources Group	A+	A2

Source: C.A. Turner, *Utility Reports* , December 2001.

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Dividend Yields
June 2001 - November 2001

		Stock Price June '01 - November '01				
		High	Low	Average	Dividend	Yield
Ameren	AEE	$ 44.50	$ 36.53	$ 40.52	$ 2.54	6.27%
American Electric Power	AEP	$ 50.40	$ 39.70	$ 45.05	$ 2.40	5.33%
Cleco Corp	CNL	$ 23.72	$ 19.40	$ 21.56	$ 0.88	4.08%
DPL Inc	DPL	$ 29.65	$ 22.05	$ 25.85	$ 0.94	3.64%
FPL Group	FPL	$ 65.61	$ 51.20	$ 58.41	$ 2.24	3.84%
IDACORP (Idaho Power)	IDA	$ 39.94	$ 33.55	$ 36.75	$ 1.86	5.06%
Great Plains Energy	GXP	$ 27.35	$ 23.19	$ 25.27	$ 1.66	6.57%
Pinnacle West	PNW	$ 50.00	$ 37.65	$ 43.83	$ 1.60	3.65%
Progress Energy	PGN	$ 45.79	$ 39.25	$ 42.52	$ 2.12	4.99%
Puget Sound Energy	PSD	$ 26.95	$ 18.51	$ 22.73	$ 1.84	8.10%
Sierra Pacific	SRP	$ 17.18	$ 13.70	$ 15.44	$ 0.80	5.18%
Southern Company	SO	$ 26.00	$ 22.05	$ 24.03	$ 1.34	5.58%
Average						5.19%
Median						5.12%

Sources: America Online and Standard and Poor's *Stock Guide* , December 2001.

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Selected Electric Utility Proxy Companies

	Value Line Forecast 2004-2006			Retention	Retention
	EPS	DPS	ROE	Rate	Growth
Ameren	$ 3.75	$ 2.62	13.50%	30.13%	4.1%
American Electric Power	$ 4.75	$ 2.40	14.00%	49.47%	6.9%
Cleco Corp	$ 2.00	$ 0.96	15.50%	52.00%	8.1%
DPL Inc	$ 2.50	$ 1.00	23.00%	60.00%	13.8%
FPL Group	$ 5.25	$ 2.55	15.00%	51.43%	7.7%
IDACORP (Idaho Power)	$ 3.20	$ 1.86	11.50%	41.88%	4.8%
Great Plains Energy	$ 2.25	$ 1.66	13.50%	26.22%	3.5%
Pinnacle West	$ 4.30	$ 1.93	11.00%	55.12%	6.1%
Progress Energy	$ 4.80	$ 2.38	13.00%	50.42%	6.6%
Puget Sound Energy	$ 2.25	$ 1.84	13.00%	18.22%	2.4%
Sierra Pacific	$ 2.00	$ 1.10	10.00%	45.00%	4.5%
Southern Company	$ 2.10	$ 1.52	15.00%	27.62%	4.1%
Average					6.0%
MDU Resources	$ 2.50	$ 1.06	10.50%	57.60%	6.0%

Source: *Value Line* , October 5, November 16 and December 7, 2001.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth Rate
Estimates for Selected Electric Utility Proxy Companies

	2/3 Zacks 5-Yr Earnings Growth Est.	1/3 Retention Growth	Weighted Average
Ameren	4.40%	4.1%	4.29%
American Electric Power	6.91%	6.9%	6.92%
Cleco Corp	10.00%	8.1%	9.35%
DPL Inc	9.30%	13.8%	10.80%
FPL Group	7.12%	7.7%	7.32%
IDACORP (Idaho Power)	10.00%	4.8%	8.27%
Great Plains Energy	6.00%	3.5%	5.18%
Pinnacle West	8.67%	6.1%	7.80%
Progress Energy	7.06%	6.6%	6.89%
Puget Sound Energy	5.25%	2.4%	4.29%
Sierra Pacific	4.33%	4.5%	4.39%
Southern Company	5.31%	4.1%	4.92%
Average	7.0%	6.0%	**6.7%**
Median			**6.9%**

Sources: Zacks.com and page 6.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth DCF Calculation for Selected Electric Utility Proxy Companies

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Investor Required Return	Flotation Cost Adjustment	Cost of Capital
Ameren	6.27%	6.44%	4.29%	10.73%	1.0475	11.24%
American Electric Power	5.33%	5.56%	6.92%	12.47%	1.0475	13.07%
Cleco Corp	4.08%	4.32%	9.35%	13.67%	1.0475	14.32%
DPL Inc	3.64%	3.88%	10.80%	14.68%	1.0475	15.38%
FPL Group	3.84%	4.01%	7.32%	11.33%	1.0475	11.87%
IDACORP (Idaho Power)	5.06%	5.32%	8.27%	13.60%	1.0475	14.24%
Great Plains Energy	6.57%	6.78%	5.18%	11.96%	1.0475	12.53%
Pinnacle West	3.65%	3.83%	7.80%	11.63%	1.0475	12.18%
Progress Energy	4.99%	5.20%	6.89%	12.09%	1.0475	12.67%
Puget Sound Energy	8.10%	8.31%	4.29%	12.60%	1.0475	13.20%
Sierra Pacific	5.18%	5.32%	4.39%	9.71%	1.0475	10.17%
Southern Company	5.58%	5.75%	4.92%	10.67%	1.0475	11.18%
Average	5.19%		6.70%	12.10%		12.67%
High				14.68%		15.38%
Median				12.03%		**12.60%**
Low				9.71%		10.17%

Montana-Dakota Utilities Co.

Basic DCF Calculation
for Selected Electric Utility Proxy Companies

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Investor Required Return	Flotation Cost Adjustment	Cost of Capital
Ameren	6.27%	6.44%	4.40%	10.84%	1.0475	11.36%
American Electric Power	5.33%	5.56%	6.91%	12.47%	1.0475	13.06%
Cleco Corp	4.08%	4.34%	10.00%	14.34%	1.0475	15.02%
DPL Inc	3.64%	3.85%	9.30%	13.15%	1.0475	13.77%
FPL Group	3.84%	4.01%	7.12%	11.13%	1.0475	11.65%
IDACORP (Idaho Power)	5.06%	5.38%	10.00%	15.38%	1.0475	16.11%
Great Plains Energy	6.57%	6.82%	6.00%	12.82%	1.0475	13.42%
Pinnacle West	3.65%	3.85%	8.67%	12.52%	1.0475	13.11%
Progress Energy	4.99%	5.21%	7.06%	12.27%	1.0475	12.85%
Puget Sound Energy	8.10%	8.36%	5.25%	13.61%	1.0475	14.26%
Sierra Pacific	5.18%	5.32%	4.33%	9.65%	1.0475	10.11%
Southern Company	5.58%	5.76%	5.31%	11.07%	1.0475	11.60%
Average	5.19%		7.03%	12.44%		13.03%
High				15.38%		16.11%
Median				12.49%		**13.09%**
Low				9.65%		10.11%

Montana-Dakota Utilities Co.

Primary DCF Analysis
Computation of the Cost of Capital
for Selected Electric Utility Proxy Companies

Growth Rate Estimate (g)	6.25%	7.25%
Current Dividend Yield (D/P)	5.19%	5.19%
Quarterly Model Dividend Yield Factor (1 + .625 g)	X 1.039	X 1.045
DCF Dividend Yield Component (Y)	5.39%	5.42%
Investor Required Return (Y + g)	11.64%	12.67%
Flotation Cost Adjustment	X 1.0475	X 1.0475
Cost of Capital	12.19%	13.27%

Mid-Point **12.73%**

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Capital Structures as of September 30, 2001

	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
Ameren	$ 2,858.6	44.34%	$ 235.2	3.65%	$ 3,353.2	52.01%	$ 6,447.0
American Electric Power	$ 14,704.0	67.35%	$ -	0.00%	$ 7,129.0	32.65%	$ 21,833.0
Cleco Corp	$ 658.2	56.70%	$ 15.8	1.36%	$ 486.9	41.94%	$ 1,160.9
DPL Inc	$ 2,150.9	79.09%	$ 23.0	0.85%	$ 545.8	20.07%	$ 2,719.7
FPL Group	$ 6,435.0	50.91%	$ 226.0	1.79%	$ 5,979.0	47.30%	$ 12,640.0
IDACORP (Idaho Power)	$ 879.3	47.56%	$ 104.5	5.65%	$ 865.0	46.79%	$ 1,848.8
Great Plains Energy	$ 1,373.2	58.52%	$ 39.0	1.66%	$ 934.3	39.82%	$ 2,346.5
Pinnacle West	$ 2,749.9	52.47%	$ -	0.00%	$ 2,491.3	47.53%	$ 5,241.3
Progress Energy	$ 9,346.5	60.47%	$ -	0.00%	$ 6,110.3	39.53%	$ 15,456.8
Puget Sound Energy	$ 2,248.5	65.42%	$ 110.7	3.22%	$ 1,077.7	31.36%	$ 3,436.8
Sierra Pacific	$ 2,970.1	65.91%	$ 50.0	1.11%	$ 1,486.5	32.99%	$ 4,506.6
Southern Company	$ 8,469.5	61.25%	$ -	0.00%	$ 5,357.7	38.75%	$ 13,827.3
Average		**59.16%**		**1.61%**		**39.23%**	
Median		**59.49%**		**1.24%**		**39.67%**	

Sources: Zacks.com and *Market Guide* on America Online.

Montana-Dakota Utilities Co.

Flotation Costs Associated With
Electric Company Common Stock Issues
1996-2000

COMPANY	YEAR	MONTH	DAY	AMOUNT OFFERED ($000)	PRICE TO PUBLIC	Net Proceeds	Issue Cost as a Percent of Net Proceeds
Dynegy, Inc.	2000	APR	18	467,500	55.000	53.075	3.63%
Southern Company	2000	DEC	7	712,500	28.500	27.560	3.41%
NRG Energy Inc.	2000	MAY	30	422,550	15.000	14.100	6.38%
TNPC	2000	OCT	4	504,000	21.000	19.790	6.11%
Dynegy, Inc.	2000	OCT	12	528,750	52.875	52.655	0.42%
CMS Energy	2000	OCT	16	200,750	18.250	17.770	2.70%
GPU	1998	FEB	12	241,331	39.563	38.459	2.87%
Niagara Mohawk	1998	JUN	25	316,386	14.125	13.515	4.51%
AES	1998	SEP	4	150,000	44.625	43.183	3.34%
Northern States Pwr	1997	SEP	17	223,031	49.563	48.294	2.63%
Gothic Energy	1996	JAN	25	13,800	6.000	5.120	17.20%
Central & Southwest	1996	FEB	21	356,063	26.375	25.588	3.08%
Pacificorp	1996	MAR	5	177,438	20.875	20.216	3.26%
Calpine	1996	SEP	19	288,720	16.000	15.100	5.96%
TNP Enterprises	1996	SEP	25	42,656	24.375	23.471	3.85%
Average 1996-2000							**4.62%**

Source: Public Utility Finance Tracker.

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Direct Testimony
of
Terry L. Blinsky

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

A. Yes. My name is Terry L. Blinsky and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Electric Bulk Power Marketing Coordinator for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Electric Bulk Power Marketing Coordinator?

A. As the Electric Bulk Power Marketing Coordinator, I am responsible for the forecasting of daily power requirements of Montana-Dakota's electric customers and meeting those needs by using the economical dispatch of our available generation. I also perform the forward purchase or sale of power on daily, weekly, or monthly transactions.

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

A. I graduated from the lineman program at Mitchell Technical Institute in 1978. I began my employment with Montana-Dakota in May 1978, as an apprentice lineman. In 1983 I transferred to General Office and held the positions of Engineering Assistant and Dispatch System Operator, where I

became a North American Electric Reliability Council (NERC) certified dispatcher. I became the Electric Bulk Power Marketing Coordinator in 1998.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss current conditions in the wholesale power market and to calculate the representative level of wholesale electric sales given current conditions.

Q. Would you please describe how you sell wholesale electricity?

A. Yes. Let me first explain that Montana-Dakota uses economic dispatch principles to meet the requirements of its retail customers. Economic dispatch includes the purchasing of energy when it is a lower cost alternative than running one of our generating units. On a daily basis, Montana-Dakota calculates its retail customer load requirements by hour for the next five days, using a forecast tool that takes into account historical load and weather. We then compare the retail load requirements with available generation for the same time period. Any generation not being used to meet retail load is available for wholesale sales.

Montana-Dakota's wholesale marketing function sells electricity in the open market through the Mid-Continent Area Power Pool (MAPP). When going into the market we sell at the highest price that someone is willing to pay as long as this price is higher than Montana-Dakota's generation fuel cost.

Q. Who are the customers that Montana-Dakota sells its wholesale power to through MAPP?

A. Montana-Dakota sells to other utilities and all other entities that act as marketing agents of other companies.

Q. Has Montana-Dakota been able to achieve higher levels of wholesale sales in the last few years?

A. Yes it has.

Q. Will Montana-Dakota be able to continue making wholesale sales at the levels experienced in the last few years?

A. No. The opportunities for us to make this level of wholesale sales peaked in 2001 and will be significantly reduced in 2002 and beyond.

Q. What factors allowed Montana-Dakota to achieve the higher levels of wholesale electric sales in the last few years?

A. In my view it was a market anomaly that allowed Montana-Dakota to make the wholesale sales levels that it did in the last few years. The first factor causing higher prices in the wholesale electric market in the last few years was that demand had outpaced supply. Increasing demand for electricity had been driven by a generally robust economy. Construction of new generation facilities has been slow for a number of years and simply did not keep pace with the increasing demand for electricity. Those companies that had available generation were able to sell to those companies buying it at prevailing market prices. I should note that those market prices were higher than any we have seen in the past.

The second factor is that natural gas prices were very high, particularly in the winter of 2000-2001 and continuing through early summer 2001. This

factor made gas-fired generation very expensive and buyers were looking for less expensive alternatives such as coal-fired generation. As Montana-Dakota's generation supply mix is primarily coal-fired and we had the energy to sell, we were able to enter into a number of transactions at very favorable prices.

A third factor was that many wholesale purchasers of electricity were buying in the short term market rather than building generation or buying power under long term contracts at stable prices. Price volatility resulted which again brought opportunities to tie into short term sales at higher prices than previously experienced.

Q. What has changed that leads you to believe that Montana-Dakota will no longer be able to achieve the level of wholesale sales and resulting margins that it has experienced in the recent past?

A. The wholesale market environment has drastically changed and our opportunities to make higher wholesale sales levels no longer exist in the current market. First, demand for electricity has slowed in the face of the downturn in the general economy. Also, supply has increased with a number of new generators on line. For example, generation added or planned in the Mid-Continent Area Power Pool (MAPP) was 658 MW in 2000, 1,774 MW in 2001, 1,759 MW in 2002 and 4,440 MW for the years 2003 through 2005. With supply and demand more nearly in balance, the prices for sales into the wholesale market have fallen to historic levels, and are expected to stay there.

The second change is that natural gas prices are currently about $2.10 per dk while a year ago natural gas prices were about $9.00 per dk. No one in the industry, to my knowledge, expects gas prices to return to those higher levels. In fact, the current New York Mercantile Exchange (NYMEX) gas futures prices remain under $3.80 per dk in every month through December 2007. This significant drop in natural gas prices from those in effect a year ago makes gas-fired generation much more economical again as a generation resource for those that have it available to them and has severely cut into our ability to make sales, especially at the prices of the past.

Q. How do today's wholesale electric prices compare with the prices of a year ago?

A. I have provided a comparison of the futures prices from last year and the current futures prices. The comparison uses the NYMEX futures prices for electricity at the Cinergy trading hub as of December 2000 and those of today. The comparison is shown on Exhibit No.____ (TLB-1). As you can see, in December 2000 the futures price for July and August 2001 deliveries was at $142.50 per Mwh, which represents the highest price at that time. The current NYMEX futures prices, again for the Cinergy hub, reflect a high of only $44.00 per Mwh for July and August 2002 contracts which represents the high point for 2002. Last year the low was $43.00 per Mwh which occurred in the last quarter of 2001. This year the low is $22.90 per Mwh for contracts for March and April 2002. I should note that the NYMEX futures prices represent actual contracts between willing sellers and willing buyers.

Q. Is it anticipated that the prices for power will rebound to the levels experienced in the recent past?

A. No. Given the current supply and demand market conditions, I believe that the high prices seen in the recent past are not likely to recur. This is supported by the NYMEX futures prices. On Exhibit No.___ (TLB-2) I have listed the NYMEX electric futures for the period February 2002 through July 2003. As you can see, there is no return to the prices experienced in 2001.

Q. Have you performed a calculation of the wholesale sales and resulting margins that Montana-Dakota can expect to make in the future?

A. Yes, I have.

Q. Would you please describe that calculation?

A. Yes. The calculation is shown on Exhibit No.____(TLB-3). As the final numbers for the month of December 2001 are not available at this time, I have used the actual results for the twelve months ended November 2001. Although it is highly questionable that we will be able to sell the same quantities of wholesale power as we did in 2001, I have assumed that we will sell the same quantities that we did in the twelve months ended November 2001. Those quantities are shown for the on-peak and off-peak periods on the exhibit. I have also shown the actual total sales in dollars and the resulting margin. The margin is the total revenue received less fuel costs. As noted on the exhibit, the total margin for the twelve months ended November 2001 was $15,554,890.

I then priced the historic on-peak Mwh sales at the current NYMEX futures prices for the period February 2001 through November 2001 on a monthly basis. The NYMEX prices are those posted as of January 2, 2002. I used the February price as a proxy for January as a futures price is not available after the first of the month. The off-peak price is estimated based on the current prices obtained for off-peak sales.

Q. Would you please explain the difference between on-peak and off-peak sales and why you priced the on-peak sales at the NYMEX futures and the off-peak sales at a significantly lower level?

A. Yes. First, let me define on-peak and off-peak. On-peak is the hours of 6:00 AM through 10:00 PM central time Monday through Saturday and off-peak is all other times. On-peak is a much more sought after commodity since most companies have higher load levels during the day than at night and buyers typically purchase energy to cover their loads for on-peak periods, making on-peak energy a more tradable commodity. The NYMEX futures prices are for firm energy which by definition is the on-peak period.

Off-peak is a time when load levels are low, and most companies have excess generation available. The off-peak market commands significantly lower prices and many sellers are willing to sell essentially at incremental cost to keep power plants running at their most efficient levels or, in some cases, maintain minimum operating levels. Off-peak power is not a highly tradable commodity like on-peak power and there is no futures index for off-peak power.

Q. What is the result of your calculation?

A. As shown on the exhibit, Montana-Dakota can expect, given current market conditions, to receive a margin of about $7,247,000 assuming that it is able to sell the same level of Mwh that it did in the twelve months ended November 2001. As I mentioned earlier, it is highly questionable that we will be able to sell the same quantities of wholesale power given current market conditions. I would also note that our ability to sell the same quantities will be affected by the generation work scheduled for 2002 that is discussed in the testimony of Mr. Gress.

Q. Does this complete your testimony?

A. Yes, it does.

NYMEX FUTURES
CINERGY HUB

As of December 2000 ($/Mwh)			As of January 8, 2002 ($/Mwh)			
Jan	2001	$75.00	Jan	2002	$23.40	1/
Feb	2001	75.00	Feb	2002	23.40	
Mar	2001	51.50	Mar	2002	22.90	
Apr	2001	51.50	Apr	2002	22.90	
May	2001	54.50	May	2002	26.40	
Jun	2001	83.50	Jun	2002	34.00	
Jul	2001	142.50	Jul	2002	44.00	
Aug	2001	142.50	Aug	2002	44.00	
Sep	2001	44.00	Sep	2002	23.75	
Oct	2001	43.00	Oct	2002	23.50	
Nov	2001	43.00	Nov	2002	23.50	
Dec	2001	43.00	Dec	2002	23.50	

1/ Assumed to be the same as February 2002.

NYMEX FUTURES
CINERGY HUB
AS OF JANUARY 8, 2002
($/MWH)

Feb	2002	$23.40
Mar	2002	22.90
Apr	2002	22.90
May	2002	26.40
Jun	2002	34.00
Jul	2002	44.00
Aug	2002	44.00
Sep	2002	23.75
Oct	2002	23.50
Nov	2002	23.50
Dec	2002	23.50
Jan	2003	26.50
Feb	2003	26.50
Mar	2003	25.50
Apr	2003	25.50
May	2003	28.00
Jun	2003	35.00
Jul	2003	45.00

MONTANA-DAKOTA UTILITIES CO.
POOL SALES CALCULATION

	On-Peak Sales (Mwh)	Off-Peak Sales (Mwh)	Total Sales (Mwh)	Total Sales Revenue	Margin	Actual Fuel Cost per Mwh	Futures On-Peak Price 1/	2002 Est. Off-Peak Price	2002 Margin Estimate
Jan-01	42,675	41,265	83,940	$2,336,055	$1,316,007	$12.15	$24.00	$12.50	$519,964
Feb-01	40,903	40,002	80,905	2,081,529	1,245,423	10.33	24.00	12.50	645,591
Mar-01	52,292	43,693	95,985	2,600,162	1,564,642	10.79	24.00	12.00	743,803
Apr-01	39,727	40,154	79,881	2,193,183	1,335,859	10.73	24.00	12.00	577,972
May-01	27,343	23,548	50,891	1,345,245	459,452	17.41	27.25	12.50	153,654
Jun-01	28,866	18,586	47,452	2,088,900	1,396,597	14.59	36.25	12.50	586,415
Jul-01	32,476	26,985	59,461	3,582,253	2,640,279	15.84	47.00	13.00	935,203
Aug-01	37,571	29,082	66,653	4,066,038	2,969,765	16.45	47.00	13.00	1,047,629
Sep-01	37,593	36,413	74,006	1,437,175	644,063	10.72	25.35	12.50	615,033
Oct-01	44,942	35,572	80,514	1,575,604	591,734	12.22	24.50	12.00	544,072
Nov-01	46,911	33,155	80,066	1,530,192	639,113	11.13	24.50	12.00	656,101
Dec-00	33,640	36,892	70,532	1,796,811	751,956	14.81	24.50	12.00	222,029
Total	464,939	405,347	870,286	$26,633,148	$15,554,890				**$7,247,467**

1/ Based on 2002 Futures On-Peak prices at of January 2, 2002.

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Direct Testimony
of
Gerald L. Gress

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

A. Yes. My name is Gerald L. Gress and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Power Production Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Power Production Manager?

A. As Power Production Manager, I am responsible for the operation, maintenance and environmental compliance of Heskett Station, Lewis & Clark Station, Glendive Gas Turbine, Miles City Gas Turbine and the Williston Gas Turbines. I also represent Montana-Dakota's interests in the Coyote and Big Stone Stations.

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

A. I graduated from Purdue University, West Lafayette, Indiana, in 1971 with a Bachelor of Science degree in Electrical Engineering Technology. I also graduated from University of Evansville, Evansville, Indiana, in 1987 with a Masters in Business Administration. I am a member of the Institute of Electrical and Electronics Engineers (IEEE). I have held various positions in power production for thirty years and my present position since 1993.

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

A. Yes, I have. I have presented testimony before the Commission in Indiana.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain Montana-Dakota's generation and maintenance schedule for its generation facilities. I also will identify and explain certain 2002 capital expenditure requirements related to Montana-Dakota's generation facilities that are above the normal capital requirements level.

Q. What is Montana-Dakota's general schedule for generation outages and overhauls at its generation stations?

A. Montana-Dakota is on a three-year rotation for boiler major outages and a six-year rotation for turbine/generator (T/G) major overhauls. However, there were some unscheduled events that reduced our major expenses and outages in 2000 and 2001.

Q. Would you please explain those events and the impact they had on Montana-Dakota's schedule for maintenance and outages?

A. Yes. First, Lewis & Clark Station had a controls upgrade in 1999 and an unscheduled T/G overhaul in the summer of 1999. These events advanced the maintenance and outage schedule so it was not necessary to have a T/G overhaul in 2000 or 2001, but a boiler outage will occur in 2002. The next T/G overhaul will be in 2005.

Second, Heskett Station had a generator failure on Unit 2 in 2000 and we took advantage of this event to do a turbine major overhaul even though the T/G overhaul was scheduled for 2001. We avoided outage time and expense to do the T/G overhaul in 2001 by doing it in 2000 while the generator was being repaired. The generator failure was covered by insurance.

Third, Heskett Station Unit 1 was put into reserve shut down in 1995 and operated at low loads before and after the shut down. This allowed us the opportunity to extend the normal run time between major turbine overhauls to the spring of 2002.

Coyote Station had a boiler and T/G major overhaul in 1997 and extensive repairs were made to get the boiler upgraded for a six year run with only a minor outage in 2000. This allowed us to keep costs down. The next T/G and boiler major overhauls are scheduled for 2003.

In summary, 2000 and 2001 were minimum maintenance and low cost years. We must now resume our planned maintenance schedule with major T/G and boiler overhauls in 2002, 2003 and 2004. Planned major maintenance will increase capital expenditures in 2002, 2003 and 2004 at most of the generating facilities.

Q. Would you please explain the major projects for 2002 that represent an increase over the normal capital budget?

A. Yes. Heskett Unit 1 will have a major turbine/generator overhaul in the spring of 2002. During the outage we will replace the condenser tubes,

upgrade the control system, modify the bottom ash system, replace sootblowers, replace grate chains and perform asbestos abatement at a cost of about $906,000. This overhaul is necessary to insure the unit's availability during peak load seasons. Heskett Unit 2 is scheduled for sootblowers to clean the inbed superheater in 2002 at a cost of about $254,000. This work is necessary to prevent agglomerations from forming in the inbed superheater tube bundle that would cause a forced outage.

Lewis and Clark is scheduled for major ductwork replacement for about $533,000 and scrubber maintenance for about $259,000 in 2002. This work is necessary because the metal in the ductwork has deteriorated to the point where it has a high probability of failure which would force the unit off line.

At Coyote, the low-pressure rotor is scheduled for replacement in 2002-2003 at a cost of about $1.3 million ($804,000 in 2002) and the boiler controls will be replaced at a cost of about $1.5 million ($675,000 in 2002). This work is necessary because several low-pressure rotors of the same design have failed in service at other power plants. In fact, the rotor at Coyote failed in December of 1999 and was replaced with a spare. A new design rotor will insure reliability during peak demand periods. The control system is obsolete and repair parts are not available any more. To insure unit availability during peak demand periods, the control system must be replaced.

At Big Stone a new technology type precipitator will be installed in 2002. The project will be done in conjunction with the Department of Energy (DOE), who is also contributing to the cost, as a demonstration of the new

technology. The cost to Montana-Dakota will be about $1,193,000. This improvement is necessary because we have to reduce load when the air emissions exceed the limits imposed on the unit by the Environmental Protection Agency (EPA). The electrostatic precipitator removes particulate emissions from the stack on a coal fired power plant. The unit at Big Stone has failed several times in the past, resulting in load reductions during peak times. In order to insure the availability of the unit, protect the environment and maintain capability during peak demand periods, the electrostatic precipitator has to be rebuilt and performance improved.

In total these projects represent $4,572,000 of system-wide capital requirements that are necessary in 2002. I also would note that this represents an increase in the capital requirements for generation from the levels experienced in the last few years.

Q. Are there any other significant capital expenditures related to generation planned for the next few years?

A. Yes. Montana-Dakota plans to add a new combustion turbine generator to its system to meet the continuing needs of our retail customers. The installed cost of the new turbine will be about $20 million.

Q. When does Montana-Dakota plan to have the new turbine in service?

A. The Integrated Resource Plan (IRP) filed with the Commission in mid-2001 shows a 2005 planned in-service date for the turbine. However, in the summer season of 2001, Montana-Dakota experienced an all time peak on its electric system. The peak was 453 MW and occurred on August 7, 2001.

This peak left us 16.9 MW short of our peak load obligation and we will be charged a penalty for exceeding our capability. Given this shortfall in our peak load obligation, Montana-Dakota is now considering the possibility of moving the planned in-service date for the turbine to May 1, 2004. We have not made a final decision at this time but are studying the issue.

Q. Would the total $20 million capital requirement be spent in one year?

A. No. Assuming an in-service date of May 1, 2005 we will be required to spend about $2 million in 2003, about $14 million in 2004 and the remaining $4 million in early 2005. If the in-service date is moved to May 1, 2004, the dollars will have to spent in 2002, 2003 and 2004 respectively.

Q. Does this complete your 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-399-01-186

Direct Testimony
Of
Donald R. Ball

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

A. Yes. My name is Donald R. Ball and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Director of Regulatory Affairs of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Director of Regulatory Affairs?

A. As Director of Regulatory Affairs, I am responsible for revenue requirements, rate administration, economic research, rate design and load research.

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

A. I graduated from Black Hills State College, Spearfish, South Dakota, in 1969 with a Bachelor of Science degree in Business Administration, with emphasis on accounting. I began my career with Montana-Dakota in September of 1969 at the Company's Rapid City, South Dakota office. I held various positions in the Company before achieving my present position in 1999.

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

A. Yes, I have. On a number of occasions, I have presented testimony before the Commissions in Montana, North Dakota, South Dakota and Wyoming. I have also testified before the Federal Energy Regulatory Commission (FERC) regarding Montana-Dakota's rates and purchased gas cost adjustments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to identify and explain certain known and measurable changes to the cost of providing electric service for the 2000 test year chosen by the North Dakota Public Service Commission Staff (Staff). The adjustments that I will describe represent changes in the cost of providing electric service that are not reflected in the Staff case and must be considered in determining whether the existing rates are just and reasonable. The Staff case is not representative of the costs incurred by Montana-Dakota in providing electric service to its North Dakota retail customers. Ms. Mulkern, a later Company witness, will include the effects of these adjustments in her testimony.

Q. Would you please describe the adjustments you propose to operation and maintenance expense?

A. Yes. The adjustments that I propose for operation and maintenance expense are as follows:

- ✓ Demand Penalty - This adjustment is for penalties that will be assessed by MAPP as Montana-Dakota, despite its best efforts to have sufficient capacity to meet its reserve obligation for retail customers, was 6.3 MW

deficient in capacity in the summer of 2000 and deficient in capacity by 16.9 MW in 2001. MAPP has not yet assessed the penalties but, given their past practice, the penalty for 2000 will be assessed and paid this year and the 2001 penalty will be assessed and paid in 2003. The amount for 2000 is $375,000 on a system-wide basis. The penalty consists of two components, a capacity charge and a transmission charge. The amount for 2001 will be about $1,007,000 and consists of the same two components. As Montana-Dakota is required to make these payments, which are associated with providing electric service to retail customers, it is appropriate to recognize the expense in the cost of service determination. As the 2000 penalty relates to the calendar year 2000 used by the Staff, it is appropriate to include the $375,000 for the 2000 penalty.

✓ AVS Major Maintenance - This adjustment relates to the Antelope Valley generating station Unit II (AVS-II). The unit is owned and operated by Basin Electric Power Cooperative and Montana-Dakota purchases about 66 MW on a firm basis under a long term purchase contract. Although Montana-Dakota does not have an ownership interest in the unit, the contract terms and conditions require that Montana-Dakota pay its portion of all costs of the unit based on the 66 MW purchase level, including major maintenance. AVS-II is on a three year maintenance schedule and such major maintenance occurred in 2001. As such, there is no amount reflected in the Staff analysis that would recognize this expense. In 2001,

Montana-Dakota was billed $1.4 million in additional costs related to the major maintenance. As the major maintenance is scheduled for every three years, it is appropriate to amortize these costs over a three year period in the cost of service determination. This equates to an annual expense of $460,000 for Montana-Dakota on a system-wide basis.

- ✓ MISO RTO – This adjustment relates to changing costs as a result of Montana-Dakota joining the Midwest Independent System Operator Inc. (MISO) regional transmission organization (RTO). Pursuant to Federal Energy Regulatory Commission (FERC) Order No. 2000, Montana-Dakota investigated a number of options for compliance and joined MISO in September, 2001. The major cost change under MISO is that Montana-Dakota will no longer receive transmission revenues which were formerly received under MAPP Service Schedule F for power transmitted on or across its system. This revenue stream will not be replicated under the MISO pricing structure. The impact of this loss in revenues is $563,000 annually on a system-wide basis.
- ✓ Labor - On January 1, 2001, there was an average 4.32% increase in wages for Montana-Dakota employees. On January 1, 2002, there was an average 3.5% increase in wages granted to employees. As the Staff analysis reflects results for the calendar year 2000, the current wage levels are not reflected although the expenses are currently being experienced. The change amounts to $984,000 applicable to North Dakota electric operations.

- ✓ Pension & Benefits- Montana-Dakota is experiencing a substantial increase in pension and post retirement benefit costs. The increases are based on information received from the Company's actuary, Towers Perrin. The increases are caused by two primary factors. The first is that the asset returns are substantially lower than the abnormally high returns received in recent years and the second is that the discount rate used to measure the liability will decrease to reflect current long term interest rates. Both of these factors drive up the cost. The increases are expected to continue through 2006 but only the 2002 amount is reflected in the data provided in this testimony. The amount applicable to North Dakota electric operations for 2002 is $114,000.

  I also have included $624,000 for North Dakota electric operations related to the Company's Supplemental Income Security Plan which provides a supplemental pension benefit to key employees. This supplemental pension benefit is necessary to attract and retain high quality staff in a number of key positions within the company.

- ✓ Insurance Expense- Insurance costs were increasing prior to September 11, 2001, but after the tragic events of that day, the effect was exacerbated. Based on discussions and negotiations with carriers, some categories of insurance are going up 50 to 70 percent. This is not unique to Montana-Dakota. Factoring in the increases to the costs for the calendar year 2000 included in the Staff analysis requires an adjustment of $116,000 applicable to North Dakota electric operations.

- ✓ Contributions, Energy Share of North Dakota - Energy Share of North Dakota 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 impact on arrears and ultimately helps with uncollectible accounts for Montana-Dakota. It also provides a needed service for those who are experiencing difficulty in paying their bills. Energy Share of North Dakota also performs weatherization and repair services which helps to conserve energy and assure that customers have safe equipment. As such, I believe it is appropriate to include this expense. The amount is $9,000 for electric operations.
- ✓ Contributions, Lignite Energy Council - The Lignite Energy Council's (LEC) primary objective is to maintain a viable lignite coal industry and enhance development of the region's lignite coal resources for use in generating electricity, synthetic natural gas and viable byproducts. The LEC's critical role of maintaining the viability of the lignite coal industry and developing the region's lignite coal resources is essential in enabling Montana-Dakota to fulfill its commitment to provide reliable, low cost electric service to its customers by way of reliable, economic fuel for generation.

  Also, enhanced development of the lignite coal industry provides economic stimulus to the region. According to the LEC, over 18,000 jobs, $1.3 billion in business volume and $60 million in tax revenue are generated by the lignite industry for the State of North Dakota each year. In addition, the LEC's Research, Development and Marketing Program

provides grants to assist research and development, preserve and enhance jobs and production and ensure economic growth, stability and opportunity. The research and development activities have allowed plants to operate more efficiently, more environmentally friendly and more economically, resulting in electric service benefits for all customers. Participation in the LEC, including financial participation in the form of contributions, is simply a legitimate, responsible and reasonable cost of doing business. Inclusion of this contribution in the cost of service will merely afford Montana-Dakota the opportunity to recover its legitimate costs of doing business. For these reasons, LEC contributions should be included in the cost of service in this proceeding. The amount applicable to North Dakota electric operations is $24,000.

Q. Would you please explain the adjustments you made to rate base?

A. The rate base adjustments I have made reflect added capital requirements for 2002, that is, requirements above the capital requirement level that we have had in recent years that should be adopted by the Commission in its determination in this proceeding. The adjustments are as follows:

- ✓ Transmission Line – This adjustment to rate base is a capital expenditure of $668,000 for refurbishing the Heskett-Bismarck 115 KV transmission line. The conductor must be replaced to enhance the reliability of the line.
- ✓ Underground Distribution Cable – This adjustment relates to the replacement of underground distribution cable of the pre-1984 vintage.

We have been experiencing an increasing number of faults on such cable and will have increased capital expenditures in 2002 of about $250,000 for replacement.

- ✓ Fleet Vehicle & Work Equipment - Another significant capital expenditure that will be incurred in 2002 is $463,000 of increased fleet vehicle and work equipment needs.
- ✓ Prepayments – This adjustment to rate base reflects the inclusion of the average balance of prepayments related to the flexible spending account benefit for employees. Employees can elect to deduct certain amounts from their pay every two weeks to use for medical and child care expenses. However, the expenditures for qualified costs exceed the balance available in the early part of the year and Montana-Dakota funds a prepayment so that employees can use the spending accounts as they incur the costs. The amount of the average prepayment is $15,000 for North Dakota electric operations.

I should note that there are related adjustments for depreciation expense, depreciation reserve and deferred taxes for the rate base adjustments which are quantified by Ms. Mulkern.

Q. Yes. Does this complete your 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-399-01-186

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 with the South Dakota Public Utilities Commission.

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

A. The purpose of my testimony is to quantify the adjustments to the North Dakota Public Service Commission Staff (Staff) case discussed by Mr. Gaske, Mr. Blinsky, Mr. Gress and Mr. Ball, and the effects of those adjustments on the North Dakota electric revenue requirement. I am sponsoring Exhibit No.___(RAM-1) and Exhibit No. ___(RAM-2) which quantify the effect of these adjustments to the Staff case on the North Dakota electric revenue requirement.

Q. Would you explain Exhibit No. ___(RAM-1)?

A. Yes. The exhibit summarizes the adjustments to the income statement and rate base as supported by the other witnesses. Each of the adjustments was developed either on a total company basis and allocated to North Dakota electric operations or calculated on a North Dakota electric basis.

Q. What does Exhibit No.___(RAM-1) show?

A. Exhibit No. ___(RAM-1), page 1 is a summary showing the income statement and rate of return for 2000, the Staff adjustments and position, Montana-Dakota's adjustments from Exhibit No. ___(RAM-1), and the resulting adjusted income statement, rate of return and revenue deficiency calculation. Page 2 shows similar rate base information

Q. What effect do the adjustments have on the revenue requirement?

A. As shown on Page 1 under the column labeled "Adjusted", Montana-

Dakota's adjusted return on equity is 12.112%, below the 12.75% return on equity required. Montana-Dakota will experience a revenue deficiency of $710,000 at a 12.75% return on equity based on the adjusted calendar year 2000 results.

Q. Does that complete your testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ADJUSTMENTS TO STAFF CASE
2000 TEST YEAR

	Total Company	North Dakota
Revenue		
Pool Sales		($4,266)
O&M		
Demand Penalty	$375	$259
AVS major maintenance	460	317
RTO	563	370
Labor		984
Pension & Benefits		738
Insurance	179	116
Contributions	46	33
		$2,817
Depreciation		$117
Income Taxes		($3,065)
Net Adjustments to Income		($4,135)
Rate Base		
Plant in Service	$5,953	$4,325
Accumulated Reserve for Depreciation		71
Net Plant		4,254
Additions		
Prepayments	23	15
Deductions		
Acc. Deferred Inc. Taxes		65
Adjustments to Rate Base		$4,204

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ND STAFF CASE
AND MONTANA-DAKOTA ADJUSTMENTS
2000 TEST YEAR

	2000	Staff Adjustments	Staff Test Year	Montana-Dakota Adjustments	Adjusted
Operating Revenues:					
Sales	$79,238		$79,238		$79,238
Sales for Resale	15,034	$2,278	17,312	($4,266)	13,046
Other Operating Revenues	2,691		2,691		2,691
Total Operating Revenues	$96,963	$2,278	$99,241	($4,266)	$94,975
Operating Expenses:					
Production Expense	$38,365	($213)	38,152	$822	38,974
Transmission Expense	3,567		3,567	476	4,043
Distribution Expense	4,660		4,660	267	4,927
Customer Accounts Expense	2,113		2,113	113	2,226
Customer Service & Info. Exp.	105		105	5	110
Sales Expense	269		269	13	282
Administration & General Exp.	8,154		8,154	1,121	9,275
	57,233	(213)	57,020	2,817	59,837
Depreciation Expense	11,803		11,803	117	11,920
Taxes Other than Income	3,811		3,811		3,811
Income Taxes	6,750	1,399	8,149	(3,065)	5,084
Total Operating Expenses	79,597	1,186	80,783	(131)	80,652
Net Income	$17,366	$1,092	$18,458	($4,135)	$14,323
Average Rate Base	$133,667		$133,667	$4,204	$137,871
Rate of Return on Avg. Rate Bas	12.992%		13.809%		10.389%
Less: Weighted Cost of LTD	4.737%		3.960%		4.230%
Weighted Cost of Pref. Sto	0.222%		0.240%		0.240%
Weighted Return on Equity	8.033%		9.609%		5.919%
% of Equity to Capital Structure	44.756%		48.870%		48.870%
Return on Equity	17.948%		19.662%		12.112%
Required Return			9.673%		10.700%
Income Requirement			$12,930		$14,752
Pro Forma Net Income			18,458		14,323
Income Deficiency (Excess)			($5,528)		$429
Revenue Deficiency (Excess)			($9,154)		$710

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ND STAFF CASE
AND MONTANA-DAKOTA ADJUSTMENTS
2000 TEST YEAR

	2000	Staff Adjustments	Staff Test Year	Montana-Dakota Adjustments	Adjusted
Rate Base:					
Plant in Service	$375,348		$375,348	$4,325	$379,673
Less: Accumulated Depreciatio	202,072		202,072	71	202,143
Construct. Work in Prog.	850		850		850
Net Plant in Service	$174,126		$174,126	$4,254	$178,380
Additions:					
Materials and Supplies	3,202		3,202		3,202
Fuel Stocks	1,277		1,277		1,277
Prepayments	209		209	15	224
Total Additions	$4,688		$4,688	$15	$4,703
Deductions:					
Accum. Deferred Income Taxes	41,564		41,564	65	41,629
Accumulated Deferred ITC's	3,074		3,074		3,074
Cust. Advances for Construct.	509		509		509
Total Deductions	45,147		$45,147	$65	$45,212
Rate Base	$133,667		$133,667	$4,204	$137,871