MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2015.6.___

Direct Testimony
of
Nicole A. Kivisto

Q. Please state your name and business address.

A. My name is Nicole A. Kivisto and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the President and Chief Executive Officer (CEO) of Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc. I am also the President and CEO of Cascade Natural Gas Corporation and Intermountain Gas Company; subsidiaries of MDU Resources Group, Inc.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above mentioned companies that, in combination, serve over one million customers in eight states.

1 **Q. Please outline your educational and professional background.**

2 A. I hold a Bachelor's Degree in Accounting from Minnesota State
3 University Moorhead. I have worked for MDU Resources/Montana-Dakota
4 for twenty years and have been in my current capacity since January
5 2015. I was the Vice President-Operations of Montana-Dakota and Great
6 Plains Natural Gas Co., Divisions of MDU Resources Group, Inc. from
7 January of 2014 until assuming my present position.

8 Prior to that, I was the Vice President, Controller and Chief
9 Accounting Officer for MDU Resources for nearly four years, and held
10 other finance related positions prior to that.

11 **Q. What is the purpose of your testimony?**

12 A. The purpose of my testimony is to provide an overview of the
13 Company's Montana electric operations, explain the Company's request
14 for an electric rate increase and discuss the policies and reasons
15 underlying the major aspects of the request. I will also address the
16 request for an interim increase and introduce the other Company
17 witnesses that will present testimony and exhibits in further support of the
18 Company's request.

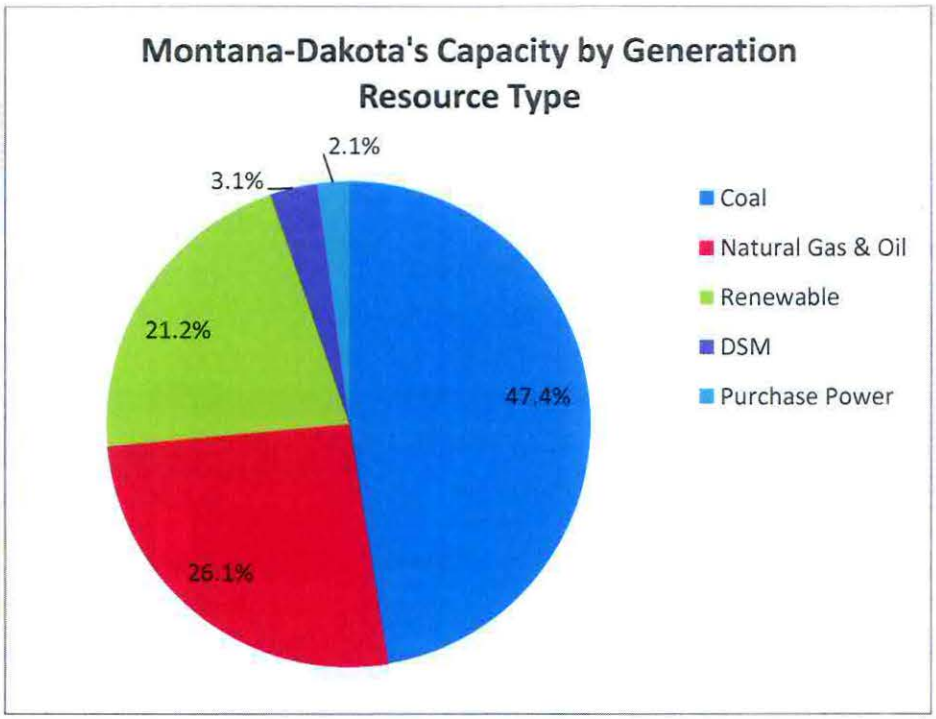
19 **Q. Would you provide a summary of Montana-Dakota's electric**
20 **operations in Montana?**

21 A. Montana-Dakota's electric system consists of generation,
22 transmission, distribution, and general plant facilities serving
23 approximately 25,840 customers in 30 communities in Montana. The

Company's Montana electric service area is served under one operating region with the regional office located in Dickinson, North Dakota and a number of district offices located in communities throughout Montana. As of December 31, 2014, the Company had 142 full and part time employees who live and work throughout our Montana electric and gas service area.

Q. **Describe Montana-Dakota's interconnected electric system.**

A. Through its interconnected electric system, Montana-Dakota serves approximately 140,000 retail customers in portions of Montana, North Dakota, and South Dakota. The Company's capacity mix is as shown below including the new resource additions described in this filing as well as the Company's Integrated Resource Plan that will be filed with the Commission on July 1, 2015.



1 **Q. Ms. Kivisto, did you authorize the filing of the rate application in this**
2 **proceeding?**
3 A. Yes, I did.
4 **Q. Why has Montana-Dakota filed this application for an electric rate**
5 **increase?**
6 A. Montana-Dakota is requesting an increase in its general electric
7 rates at this time because our current rates do not reflect the cost of
8 providing electric service to our Montana customers.
9 **Q. What is the amount of the increase requested?**
10 A. As will be fully explained by other Company witnesses, the
11 Company is requesting an electric rate increase of $11,755,752 (a 21.1
12 percent increase over current rates) based on a 2014 test year adjusted
13 for known and measurable changes.
14 **Q. How will the requested increase affect the various classes of**
15 **customers?**
16 A. The Company is proposing an equal percentage change to each
17 customer class of 21.1 percent. This proposed increase reflects an
18 increase of $14.80 per month or approximately $178.00 on an annual
19 basis.
20 **Q. What are the primary reasons that Montana-Dakota needs an**
21 **increase at this time?**
22 A. There are multiple factors that make up the amount requested.
23 Many factors came together all at once to force the concurrent

construction of several new projects. These factors include: the multitude of new regulations issued by the Environmental Protection Agency (EPA); the rapid development of oil exploration in northeast Montana and northwest North Dakota; the expiration of very favorable transmission agreements with the Western Area Power Administration (WAPA) along with WAPA and Basin Electric choosing to join the Southwest Power Pool instead of MISO; and the previous expiration of a long-term baseload Power Purchase Agreement with Basin Electric and subsequent efforts to replace that energy and capacity. These issues, though known, have converged all at once resulting in Montana-Dakota needing to: install pollution controls to allow existing units to continue to provide energy and capacity at costs lower than adding more new resources, add new generation to supply additional and replacement energy and capacity; and build additional transmission, as well as incur additional transmission costs from others.

These three major reasons for this request are summarized with additional detail, as follows:

1. The need to make modifications at generation facilities to comply with new Environmental Protection Agency (EPA) requirements and the increased operating costs of this compliance effort to keep the low cost generating units operating, including:

- Modifications required to the Lewis & Clark coal fired station located at Sidney, Montana necessary to comply with the EPA Mercury and Air Toxics Standard; and
- The Air Quality Control System (AQCS) being installed on the Big Stone coal fired station located at Big Stone City, South Dakota required to meet EPA's Regional Haze regulation and mercury control equipment required under the Mercury and Air Toxics Standard.

Compliance dates for these projects are dictated by the EPA, and are not within Montana-Dakota's control. Montana-Dakota will show through its Integrated Resource modelling, discussed in more detail by Mr. Neigum, that the installation of the required equipment was the least cost alternative. The investment associated with the projects represents approximately 32 percent of the requested increase in rates.

2. The need to add, and/or replace, capacity and energy requirements including:

- The 107.5 MW Thunder Spirit Wind Project which is expected to go into service in December of this year;
- Two Reciprocating Internal Combustion Engines (RICE Units) being added at the Lewis & Clark Station for a total of 18.6 additional MWs; and

- The 88 MW Heskett III Simple Cycle Combustion Turbine which went into service in the fall of 2014.

The need to provide additional energy and capacity resources was driven by the rapid oil development in eastern Montana and Western North Dakota that affected the majority of the interconnected system with customer additions associated with the activity, along with the expiration of the 66 MW Basin Electric long-term capacity and energy Purchased Power Agreement (PPA) in 2006. Montana-Dakota had attempted to replace the Basin Electric PPA with a new base load unit but those efforts were derailed by the partners in the Big Stone II unit abandoning the project. The timing of these needed resources happened to coincide with the compliance time frames of EPA Regional Haze and MATS rules. The incremental needs were offset by favorable changes MISO made to its resource adequacy requirements in 2012 which reduced Montana-Dakota's peak demand obligations by 130 MW, which the Company did not have to construct or acquire, resulting in significant savings to customers.

3. Transmission investments needed to ensure reliability, and additional costs that will be incurred due to replacing transmission services previously provided by the Western Area Power

Administration and Basin Electric Power Cooperative that will now be provided through the Southwest Power Pool.

With each of these investments, there is additional depreciation, operation and maintenance expenses and taxes associated with the increases in investment. The table below shows the investment in electric plant assigned and allocated to Montana electric operations. The gross investment in Montana electric operations has increased by over $126 million, or approximately 60 percent, from the end of 2010 to the pro forma levels included in this case. And, as demonstrated by the production bars in the table, the majority of this increase is associated with power production resources.

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

1 A Montana-Dakota's last general electric rate case was Docket No.
2 D2010.8.82 which resulted in an increase of 6.23 percent that became
3 effective on September 1, 2011.
4 **Q. What is causing the need for additional generation at this time?**
5 A. Montana-Dakota utilizes the Integrated Resource Planning (IRP)
6 process to first identify customer capacity and energy requirements over
7 the long term and then to consider all resource options reasonably
8 available to meet the end-use customer's demand for reliable and cost-
9 effective energy. Through the last several cycles of the IRP, Montana-
10 Dakota has identified a need for incremental capacity and energy to meet
11 customer demands and to replace an expiring capacity agreement as well
12 as planning for eventual future retirements of the oldest units in the fleet.
13 The new resources included in this request for rate relief have been
14 identified and supported as best cost options in meeting customer needs
15 as more fully explained by Mr. Skabo and Mr. Neigum. I believe the
16 course we are taking will position the Company and its customers well into
17 the future while we understand the current uncertainties surrounding
18 impending EPA regulations. Montana-Dakota has effectively reduced its
19 carbon dioxide emissions intensity by more than 10 percent since 2003
20 with an estimated 20 percent reduction in emissions intensity by 2017.
21 **Q. What return is Montana-Dakota requesting in this case?**
22 Montana-Dakota is requesting an overall return of 7.588 percent,
23 inclusive of a return on equity (ROE) of 10.0 percent. Dr. Gaske's

1 analysis indicates that a 10.0 percent ROE is fully justified and supported
2 based on his Discounted Cash Flow analysis of a group of proxy
3 companies that have risks similar to those Montana-Dakota faces.
4 **Q. Is Montana-Dakota seeking interim rate relief in this proceeding?**
5 A. Yes. Interim rate relief is being sought in this case consistent with
6 the Administrative Rules of Montana (ARM) § 38.5.5 Interim Utility Rate
7 Increases. The amount of interim relief sought is $10,977,525 and reflects
8 the Company's additional generation facilities and other adjustments
9 included in the pro forma 2014 revenue requirement based on
10 Commission guidelines as described by Mr. Jacobson.
11 **Q. Is the Company seeking any new cost recovery mechanisms in this**
12 **case?**
13 A. Yes, the Company is asking the Commission to consider its
14 requests to add a Transmission Cost Recovery Rider and an
15 Environmental Cost Recovery Rider. With Basin Electric Power
16 Cooperative and the Western Area Power Administration joining the
17 Southwest Power Pool, the Company is expecting significant changes in
18 its transmission costs. In addition, transmission costs associated with the
19 Midcontinent Independent System Operator, Inc. (MISO) Multi-Value
20 Transmission projects will continue to increase as those projects are
21 placed into service. These future transmission costs will be unavoidable,
22 ongoing and necessary to ensure reliable service to customers. It is in the
23 Company's and the customers' best interest to time the recovery of these

costs as close as possible to when they are incurred. A rider allows for that ability.

Additionally, the Company is requesting to implement an Environmental Cost Recovery Rider in order to track and recover future costs associated with forthcoming environmental regulations. The environmental related costs are also best recovered through an ongoing cost recovery mechanism such that any changes – either positive or negative can be recovered from customers in a more timely fashion.

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

A. Yes. Following is a list of witnesses that will provide testimony and/or exhibits in support of the Company's application:

- Dr. J. Stephen Gaske, Senior Vice President of Concentric Energy Advisors, Inc. will testify regarding the appropriate cost of common equity for Montana-Dakota's Montana electric operations.
- Mr. Garret Senger, Executive Vice President – Regulatory Affairs and Chief Accounting Officer for Montana-Dakota, will testify regarding the overall cost of capital, capital structure and overall debt and preferred equity costs.
- Mr. Jay Skabo, Vice President of Electric Supply for Montana-Dakota, will provide an overview of the Company's electric operations and the need for environmental retrofits to the generating fleet.

- Mr. Darcy J. Neigum, System Operations and Planning Manager for Montana-Dakota, will testify regarding the need for the Company's additional generation resources. Mr. Neigum will also discuss transmission service changes as a result of the expiration of long term transmission agreements with the Western Area Power Administration (Western) and Basin Electric Power Cooperative's decision to join the Southwest Power Pool.
- Mr. Alan L. Welte, Director of Generation for Montana-Dakota, will testify regarding the technologies employed to comply with current environmental regulations.
- Mr. Travis Jacobson, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the total revenue requirement and the interim revenue requirement necessary for Montana electric operations.
- Ms. Sara J. Cardwell, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the embedded class cost of service study and marginal class cost of service study, and
- Ms. Tamie A. Aberle, Director, Regulatory Affairs for Montana-Dakota, will testify on the rate design and proposed tariff changes.

Q. Ms. Kivisto, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable as they are reflective of the total costs being incurred by Montana-Dakota in providing safe and reliable electric service to its customers. The proposed

rates will provide Montana-Dakota the opportunity to earn a fair and reasonable return on its Montana electric operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

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

Before the Public Service Commission of Montana

Docket No. D2015.6.___

Direct Testimony
of
Garret Senger

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

2 A. Yes. My name is Garret Senger and my business address is 400
3 North Fourth Street, Bismarck, North Dakota 58501. I am Executive Vice
4 President of Regulatory Affairs and Chief Accounting Officer (CAO) for
5 Montana-Dakota Utilities Co. (Montana-Dakota), and Great Plains Natural
6 Gas Co. (Great Plains), divisions of MDU Resources Group, Inc.

7 **Q. Would you please describe your duties?**

8 A. I oversee the activities of the regulatory affairs group for Montana-
9 Dakota and Great Plains. I am also responsible for providing direction and
10 management of the accounting and the financial forecasting/planning
11 functions, including the analysis and reporting of all financial transactions for
12 Montana-Dakota and Great Plains.

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

15 A. I graduated from the University of Mary with a Bachelor of Science
16 degree in Accounting and a Master's in Business Administration. I started
17 my career with Montana-Dakota in 1985 as a financial analyst in the

1 Financial Reporting area and during my tenure with the Company have
2 held positions of increasing responsibility, including Supervisor of
3 Financial Reporting, Manager of Financial Forecasting, Manager of
4 Financial Reporting & Planning, Director of Accounting and Controller, and
5 Chief Accounting Officer.

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

7 A. Yes, I have testified before the Montana Public Service
8 Commission, the North Dakota Public Service Commission and the
9 Wyoming Public Service Commission and submitted written testimony in
10 proceedings before the South Dakota Public Utilities Commission.

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

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

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

16 A. Yes, they were.

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

18 A. Yes, they are.

19 **Q. Would you describe Statement A and Statement B?**

20 A. Statement A, pages 1 and 2 show Montana-Dakota's balance sheet
21 as of December 31, 2013 and December 31, 2014 and March 31, 2014
22 and March 31, 2015 information is shown on pages 3 and 4, with notes to
23 the financial statements following. Statement B consists of Montana-

1 Dakota's income statement for the twelve months ended December 31,
2 2014 and the three months ended March 31, 2015. These statements
3 have been prepared from the Company's books and records that are
4 maintained in accordance with the Federal Energy Regulatory
5 Commission (FERC) Uniform System of Accounts.

6 **Q. Would you please explain Statement F?**

7 A. Statement F shows the average utility capital structure of Montana-
8 Dakota for the twelve months ended December 31, 2014, and the
9 projected capital structure for 2015. Statement F includes the associated
10 costs of debt, preferred stock and common equity. This capital structure
11 and the associated costs serve as the basis for the overall rate of return
12 requested by Montana-Dakota in this rate filing of 7.588 percent. The
13 Company continues its efforts to reduce the overall cost of debt. The cost
14 of long-term debt in this filing is 0.90 percent lower than requested in the
15 2010 electric rate proceeding in Montana. The basis for the requested
16 10.00 percent return on common equity contained within the overall
17 requested rate of return is supported by the testimony of Dr. J. Stephen
18 Gaske.

19 Statement F, Rule 38.5.146 summarizes the average of the actual
20 electric utility capital structure at December 31, 2014 and the projected
21 capital structure and the related utility costs of capital for 2015. As shown
22 on page 1, the components of the 2015 projected overall annual rate of
23 return, which are used by Mr. Jacobson to calculate the revenue

requirement, are:

	Weighted Cost of Capital
Long Term Debt	2.447%
Short Term Debt	0.132%
Preferred Stock	0.057%
Common Equity	4.952%
Required Rate of Return	7.588%

Page 2 of Rule 38.5.146 reflects the Company's utility common equity balance at December 31, 2013 and 2014, and the projected balance at December 31, 2015. The changes to the common equity balances reflect the normal changes, including projected earnings, as well as the effect of new stock infusions.

The debt costs reflected on Statement F, Rule 38.5.147, page 1 represent the actual weighted embedded costs of the long-term debt at December 31, 2013 and 2014, and those projected to be outstanding at December 31, 2015. In calculating the debt costs, the "Yield-to-Maturity" method (also referred to as the Internal Rate of Return (IRR) method) is used to determine the total cost for each respective debt issue as presented on Rule 38.5.147, pages 2 through 4. The yield-to-maturity calculation of each debt issue outstanding gives consideration to the stated rates of interest being paid on such debt, the timing of the interest payments, related issuance expenses, underwriters' commissions, the discount or premium realized upon issuance and the amortization of losses on bond redemption transactions.

Page 5 reflects the amortization of issuance costs associated with reacquired debt.

Page 6 reports the average short-term debt balance and the associated interest expense and cost of short-term debt for December 31, 2014 and that projected to be outstanding on December 31, 2015.

Statement F, Rule 38.5.148, supports the cost of Montana-Dakota's preferred stock capital, representing the weighted cost of the issues at December 31, 2013 and 2014 and projected to be outstanding at December 31, 2015.

Statement F, Rule 38.5.149 shows the issuance of common stock during the five year period ending December 31, 2014.

Q. How does the Company finance its electric utility operations and determine the amount of common equity, debt and preferred stock to be included in its capital structure?

A. As a regulated public utility, the Company has a duty and obligation to provide safe and reliable service to its customers across its service territory while prudently balancing cost and risk. In order to fulfill its service obligations, the Company is making significant capital expenditures for new plant investment throughout its service territory, including environmental upgrades such as the Big Stone AQCS project to comply with the regional haze rule and Lewis & Clark to comply with the MATS rule, new generation sources for capacity and energy such as the Heskett III natural gas turbine, the Thunder Spirit Wind Farm and 19 MW

1 of new natural gas generation located near the Lewis & Clark Station, as
2 well as transmission upgrades to enhance reliability across our integrated
3 system. These new investments also have associated operating and
4 maintenance costs. Through its financial planning process, the Company
5 determines the amounts of necessary financing required to support these
6 activities. Montana-Dakota finances its operations with a target of 50
7 percent common equity. Capital expenditure investments are financed
8 through a mix of internally generated funds, the utilization of the
9 Company's short-term credit line and the issuance of additional debt and
10 equity financing as required to maintain targeted capital ratios and finance
11 the combined utility operations. In 2014, the Company obtained $82.0
12 million of common equity. The Company is projected to receive an
13 additional $102.5 million in 2015 to achieve and maintain the targeted
14 capital structure. Additionally, the Company is projected to issue $150.0
15 million of new debt in 2015.
16 Since 2006, the Company has refinanced essentially all of its long-
17 term debt and has lowered its embedded weighted average debt cost from
18 8.713 percent at December 31, 2005 to a 5.949 percent at December 31,
19 2015. The mix of securities employs various maturity dates in order to
20 provide flexibility and mitigate refinancing risks.
21 **Q. What does Statement F, Rule 38.5.147 show?**
22 A. Page 1 is a summary showing the Company's long-term debt at
23 December 31, 2013 and 2014 and associated cost of debt, and it shows

1 the projected long-term debt and associated costs for 2015, as well as the
2 average cost of debt for the two periods. Page 2 and 3 shows the cost
3 and the debt balance by issue at December 31, 2013 and 2014 and page
4 4 shows the projected cost and the debt balance by issue at December
5 31, 2015.
6 **Q. How did you derive the projected cost of debt for 2015?**
7 A. The projected cost of debt for 2015 is based upon the yield to
8 maturity of each debt issue outstanding.
9 **Q. Would you please describe Statement F, Rule 38.5.147, page 5 and**
10 **explain the amortization method utilized?**
11 A. Page 5 reflects the annual amortization of the costs associated with
12 the redemption of long-term debt. For this proceeding, the amortization
13 has been computed on a straight-line basis over the remaining life of the
14 issues. The Company uses the same calculation for accounting purposes.
15 **Q. Would you please describe Statement F, Rule 38.5.147, page 6?**
16 A. Page 6 presents the average short-term debt balance for 2014 and
17 projected for 2015 as well as the average cost of short-term debt. A
18 twelve-month average of short-term debt is used in the cost of capital
19 calculation to reflect the seasonality in the short-term debt balance. Short-
20 term debt is historically at or near its peak in December and the twelve-
21 month average calculation is more reflective of the borrowing level than a
22 year-end balance.
23 **Q. What does Statement F, Rule 38.5.148 show?**

1 A. Page 1 presents the preferred stock balances at December 31,
2 2013 and 2014, and the projected balances for December 31, 2015. The
3 anticipated weighted cost of preferred stock is also shown. Page 2 and 3
4 set forth the various preferred stock issues outstanding at December 31,
5 2013 and 2014 and page 4 sets forth the projected issues outstanding at
6 December 31, 2015.

7 **Q. What does Statement F, Rule 38.5.149 show?**

8 A. The schedule shows the issuances of shares of common stock for
9 the five-year period ending December 31, 2014.

10 **Q. What does Statement F, Rule 38.5.150 show?**

11 A. This schedule shows that there has been no stock split or stock
12 dividend activity in the five years ended December 2014.

13 **Q. Would you please describe Statement F, Rule 38.5.151?**

14 A. This schedule presents various financial and market data relative to
15 the Company's common stock for the years ended 2010 through 2014,
16 and for each month of the twelve month period ended December 31,
17 2014.

18 **Q. Would you please describe Statement F, Rule 38.5.152?**

19 A. This schedule shows the reacquisition activity for long-term debt in
20 the last five years and shows a summary of scheduled retirements of
21 preferred stock for the five years ended December 31, 2014.

22 **Q. Does this conclude your direct testimony?**

23 A. Yes, it does.

Exhibit No.___(JSG-1)

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

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

D2015.6.___

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

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

A1. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors, Inc., 1130 Connecticut Avenue NW, Suite 850, Washington, DC 20036.

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

A2. 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 earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates ("HZA") as a research assistant and later as supervisor of regulatory research. Subsequently, I spent a year assisting 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 to 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 HZA and was President of the company from 2000 to 2008. In May 2008, HZA merged with Concentric Energy Advisors, Inc. ("Concentric") and I became a Senior Vice President of Concentric.

Q3. Have you presented expert testimony in other proceedings?

A3. Yes. I have filed testimony on the cost of capital and capital structure issues for electric and natural gas distribution and oil and natural gas pipeline operations before 11 state and provincial regulatory bodies, including the Montana Public Service Commission. I also have testified or filed testimony or affidavits before various federal regulators, including the Federal Energy Regulatory Commission on more than thirty occasions, the National Energy Board of Canada, and the Comisión Reguladora de Energía of México. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, revenue requirements, and market power. In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing and generating plant economics before the U.S. Postal Rate Commission, regulators in four Canadian provinces, and seven U.S. state public utility commissions. During the course of my consulting career, I have conducted many studies on issues related to regulated

industries and have served as an advisor to numerous clients on economic, competitive, and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals courses. Finally, I am a member of the American Economic Association, the Financial Management Association, and the American Finance Association.

I. INTRODUCTION

A. Scope and Overview

Q4. What is the scope of your testimony in this proceeding?

A4. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company") to estimate the cost of common equity capital for the Company's electric utility operations in the state of Montana. In this testimony, I calculate the cost of common equity capital for Montana-Dakota's Montana electric utility operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Montana-Dakota's Montana electric utility 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.

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

A5. Based on its test period capital structure, Montana-Dakota is requesting the following rate of return:

Table 1: Requested Rate of Return – Montana Electric Utility Operations[1]

Source	Amount	Percent	Cost	Overall Rate of Return
Long-Term Debt	$505,460	41.14%	5.95%	2.45%
Short-Term Debt	$99,624	8.11%	1.63%	0.13%
Preferred Stock	$15,259	1.24%	4.58%	0.06%
Common Equity	$608,435	49.52%	10.00%	4.95%
TOTAL	**$1,228,778**	**100.00%**		**7.59%**

As my testimony discusses, an overall allowed rate of return of 7.59 percent, with a 10.00 percent return on common equity, represents the cost of capital for Montana-Dakota at this time.

B. Company Background

Q6. Please describe Montana-Dakota's operations and those of its parent company, MDU Resources Group, Inc.

A6. 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 Montana, North Dakota, South Dakota, and Wyoming. MDU Resources also owns Cascade Natural Gas Co., which distributes natural gas in the states of Oregon and Washington; Intermountain Gas Company, which distributes natural gas in the state of Idaho; and Great Plains Natural Gas Co., which distributes natural gas in western Minnesota and southeastern North Dakota. Through other divisions and subsidiaries, MDU Resources is engaged in utility infrastructure construction, natural gas and oil exploration and production, oil refining, natural gas gathering

[1] Projected average capital structure and rate of return for 2015.

and transmission, and produces and markets aggregates and other construction materials.

In 2014, the utility companies within MDU Resources provided electric utility service to over 138,000 residential, commercial, industrial, and municipal customers in 177 communities and adjacent rural areas across four states.[2] In addition, Montana-Dakota provided natural gas distribution service to over 892,000 residential, commercial, and industrial customers in 334 communities across eight states.[3] Electric assets comprised 13.2 percent[4] of MDU Resources' total assets in 2014, and electric revenues comprised 6.0 percent[5] of total operating revenues. Montana accounted for 21.0 percent of the retail electric utility operating revenues, while North Dakota (64.0 percent), Wyoming (10.0 percent), and South Dakota (5.0 percent) accounted for the other 79.0 percent of retail electric utility operating revenues.[6]

Montana-Dakota serves its electric utility customers across three states through an interconnected electric system consisting of ten electric generating facilities and three small portable diesel generators which have an aggregate nameplate capacity of 578 megawatts. Table 2 below presents details for Montana-Dakota's ten electric generating stations.

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2 MDU Resources Group, Inc., Form 10-K for the fiscal year ended December 31, 2014, at 7.
3 *Ibid.*, at 11.
4 *Ibid.*, at 86.
5 *Ibid.*, at29.
6 *Ibid.*, at 7.

Table 2: Montana-Dakota's Electric Generating Stations[7]

Generating Station	State	Fuel	Nameplate Capacity (kW)	2014 Net Generation (kWh)
Big Stone[8]	SD	Coal	94,111	576,957
Cedar Hills	ND	Wind	19,500	59,420
Coyote[9]	ND	Coal	103,647	682,333
Diamond Willow	MT	Wind	30,000	96,534
Diesel Units	ND	Oil	5,475	40
Glen Ullin	ND	Waste Heat	7,500	31,441
Glendive	MT	Natural Gas	75,522	1,911
Heskett	ND	Coal	86,000	547,268
Heskett	ND	Gas	89,038	28,057
Lewis & Clark	MT	Coal	44,000	290,193
Miles City	MT	Natural Gas	23,150	365
			577,943	**2,314,519**

Approximately 92 percent of the energy generated by Montana-Dakota's facilities came from coal-fired power plants in 2014. When purchased power is included in the supply portfolio, approximately 79 percent of Montana-Dakota's net generation needs were satisfied by its own facilities and contracted facilities.[10] On December 22, 2014, the Company filed an application for advance determination of prudence and certificate of public convenience and necessity with the North Dakota Public Service Commission for the Thunder Spirit Wind Project. This project will provide energy, capacity, and renewable energy credits to MDU electric customers in North Dakota, Montana and South Dakota. The projected cost is approximately $220 million. In addition, the Lewis & Clark Reciprocating Internal Combustion Engine

7 *Ibid.*, at 9.
8 Reflects Montana-Dakota's partial ownership interest.
9 Reflects Montana-Dakota's partial ownership interest.
10 MDU has one purchase power agreement for 120 MW for the period June 1, 2014 to May 31, 2015.

1 project is estimated for completion for the fall of 2015 at an approximate cost of
2 $43 million.

3 In addition to new generation additions, the Company must also invest in
4 environmental controls to comply with federal and state environmental rules. The
5 Lewis and Clark Station must comply with the Environmental Protection Agency's
6 ("EPA") Mercury and Air Toxics Standards ("MATS"), and the Big Stone Plant
7 ("Big Stone") must comply with the South Dakota Implementation Plan ("SIP")
8 that was developed to comply with the EPA Regional Haze Rule. Each of these
9 projects requires significant capital. Without the environmental upgrades at Big
10 Stone, the plant would be forced to close.

11 **Q7. Would you please describe Montana-Dakota's Montana electric utility service**
12 **territory?**

13 A7. Montana-Dakota provides electric utility service to approximately 25,840
14 customers[11] in 30 communities in Montana.[12] Although Montana-Dakota's
15 Montana electric utility operations tend to be concentrated in cities and towns, a
16 large portion of the local economies are based on agriculture. The economy of
17 eastern Montana is primarily agricultural with some oil production. From an
18 economic perspective, the mostly rural nature of eastern Montana poses
19 accessibility challenges, resulting in less access to markets and high transportation
20 costs to larger markets. In addition, rural county residents lack access to the same

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[11] Customer count as of May 31, 2015.
[12] Montana-Dakota Utilities Co., State of Montana Electric Rate Schedule, Volume No. 4, Original Sheet No. 2.

variety of goods and services available in more heavily populated areas of the country.

As discussed above and in the Direct Testimony of Montana-Dakota witnesses Mr. Jay Skabo, Mr. Darcy J. Neigum and Mr. Alan L. Welte, significant investment will continue to be required in coming years to support customer growth and to replace aging plant so that the Company can continue to provide safe, reliable and efficient electric utility service to its Montana customers. Montana-Dakota will require an adequate return in order to attract capital for these projects.

II. FINANCIAL MARKET STUDIES

A. Criteria for a Fair Rate of Return

Q8. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company.

A8. 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 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.

Q9. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A9. The same standards should apply. When an unregulated entity faces competition, the pressure of that competition and consumer choices will combine to determine the fair rate of return. However, 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, both the consumer and the public interest depend on establishing a return that will readily attract capital without being excessive.

Q10. How are the costs of preferred stock and long-term debt determined?

A10. 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.

1 **Q11. How is the cost of common equity determined?**

2 A11. The practice in setting a fair rate of return on common equity is to use the current
3 market cost of common equity in order to ensure that the return is adequate to attract
4 capital and is commensurate with returns available on other investments with
5 similar levels of risk. However, determining the market cost of common equity is
6 a relatively complicated task that requires analysis of many factors and some degree
7 of judgment by an analyst. The current market cost of capital for securities that pay
8 a fixed level of interest or dividends is relatively easy to determine. For example,
9 the current market cost of debt for publicly-traded bonds can be calculated as the
10 yield-to-maturity, adjusted for flotation costs, based on the current market price at
11 which the bonds are selling. In contrast, because common stockholders receive
12 only the residual earnings of the company, there are no fixed contractual payments
13 which can be observed. This uncertainty associated with the dividends that
14 eventually will be paid greatly complicates the task of estimating the cost of
15 common equity capital. For purposes of this testimony, I have relied on several
16 analytical approaches for estimating the cost of common equity. My primary
17 approach relies on three DCF analyses. In addition, I have conducted a risk
18 premium analysis and a market DCF analysis of the S&P 500 as benchmarks to
19 assess the reasonableness of the DCF results. Each of these approaches is described
20 later in this testimony.

1 B. Interest Rates and the Economy

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

3 A12. Companies attempting to attract common equity must compete with a variety of
4 alternative investments. Prevailing interest rates and other measures of economic
5 trends influence investors' perceptions of the economic outlook and its implications
6 on both short- and long-term capital markets. Page 1 of Schedule 1 of Exhibit
7 No.___(JSG-2) shows various general economic statistics. Real growth in the
8 Gross Domestic Product ("GDP") has averaged 2.7 percent annually during the past
9 30 years, 2.5 percent for the past 20 years, and 1.6 percent for the past 10 years.
10 After increasing at an annual rate of 2.2 percent in the fourth quarter of 2014, the
11 Bureau of Economic Analysis announced that in the first quarter of 2015 real GDP
12 declined at an annual rate of 0.7 percent.[13] According to Blue Chip Economic
13 Indicators, the consensus forecast for expected growth in real GDP is 2.5 percent
14 in 2015[14] and 2.8 percent in 2016.[15] Likewise, the U.S. unemployment rate has
15 improved in recent months to 5.4 percent as of April 2015,[16] but the labor force
16 participation rate for civilians 16 years and over remained at 62.8 percent as of
17 April 2015, the lowest rate since the late 1970s.[17] Improvements in the U.S.
18 unemployment rate are partly attributed to the reduced U.S. labor force and are not
19 fully explained by job growth. In light of these weak economic conditions, the
20 Federal Reserve has maintained its federal funds rate of 0.00 percent to 0.25 percent

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13 U.S. Department of Commerce, Bureau of Economic Analysis, News Release, May 29, 2015.
14 Blue Chip Economic Indicators, Vol. 40, No. 5, May 10, 2015, at 2.
15 *Ibid.*, at 3.
16 U.S. Department of Labor, Bureau of Labor Statistics, News Release, May 8, 2015.
17 U.S. Department of Labor, Bureau of Labor Statistics, civilian labor force participation rate, 16 years and over, seasonally adjusted.

1 for overnight loans to banks in order to provide continued liquidity to the U.S.
2 financial markets.[18]

3 As pages 2 and 3 of Schedule 1 of Exhibit No.___(JSG-2) show, interest rates on
4 longer-term public utility bonds have decreased by approximately 50 basis points
5 over the past three years. From July 2014 through April 2015, the average yield on
6 A-rated public utility bonds was 3.94 percent and the average yield on Baa-rated
7 public utility bonds was 4.61 percent. Credit spreads, which measure the
8 incremental cost of corporate debt relative to U.S. Treasury bonds, have increased
9 in recent months after declining during the past three years with the average spread
10 of A-rated utility bonds over 30-year U.S. Treasury bonds at 1.05 percent for the
11 period from July 2014 through April 2015. Similarly, the average spread of Baa-
12 rated utility bonds over 30-year U.S. Treasury bonds was 1.71 percent over the
13 same ten month period.

14 Investors also are influenced by both the historical and projected level of inflation.
15 As also shown on Page 1 of Schedule 1 of Exhibit No.___(JSG-2), during the past
16 decade, the Consumer Price Index has increased at an average annual rate of 2.3
17 percent and the GDP Implicit Price Deflator, a measure of price changes for all
18 goods produced in the United States, has increased at an average rate of 2.0 percent.
19 According to Blue Chip Economic Indicators, the Consumer Price Index is
20 forecasted to increase by 0.2 percent[19] and 2.2 percent[20] for 2015 and 2016,

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18 Statement of the Federal Open Market Committee, April 29, 2015.
19 Blue Chip Economic Indicators, Vol. 40, No.5, May 10, 2015, at 2.
20 *Ibid.*, at 3.

respectively. Over the intermediate and longer-term, however, investors can expect higher inflation rates as the Federal Reserve's accommodative monetary policy, which began in 2008, places upward pressure on consumer and producer prices once economic growth returns to historical levels. According to Blue Chip Financial Forecasts, the projected yield on 30-year U.S. Treasury bonds from 2016 to 2020 is 4.9 percent and from 2021 to 2025 it is 5.1 percent.[21] These interest rates are significantly higher than the current yield on the 30-year U.S. Treasury bond, suggesting that investors expect a substantial increase in inflationary pressure over the intermediate and long-term periods.

Q13. How are current economic conditions reflected in the equity markets?

A13. Although corporate bond yields are lower than pre-crisis levels, primarily due to Federal Reserve monetary policy, credit spreads for intermediate quality corporate bonds remain somewhat higher than pre-crisis levels as investors remain risk averse and inflation fears increase. The equity markets generally have recovered from the large stock market decline in 2008 and 2009. However, the premium required in the cost of common equity generally is higher than it was before the significant risks of equity investment were emphasized during the recent market downturn. In addition, the Federal Reserve's massive purchases of federal debt have created artificially low interest rates that do not reflect the risks and returns required in the equity market.

[21] Blue Chip Financial Forecasts, Vol. 33, No. 6, December 1, 2014, at 14.

1 C. Discounted Cash Flow ("DCF") Method

2 **Q14. Please describe the DCF method of estimating the cost of common equity**
3 **capital.**

4 A14. The DCF method reflects the assumption that the market price of a share of
5 common stock represents the discounted present value of the stream of all future
6 dividends that investors expect the firm to pay. The DCF method suggests that
7 investors in common stocks expect to realize returns from two sources: a current
8 dividend yield plus expected growth in the value of their shares as a result of future
9 dividend increases. Estimating the cost of capital with the DCF method, therefore,
10 is a matter of calculating the current dividend yield and estimating the long-term
11 future growth rate in dividends that investors reasonably expect from a company.

12 The dividend yield portion of the DCF method utilizes readily-available
13 information regarding stock prices and dividends. The market price of a firm's
14 stock reflects investors' assessments of risks and potential earnings as well as their
15 assessments of alternative opportunities in the competitive financial markets. By
16 using the market price to calculate the dividend yield, the DCF method implicitly
17 recognizes investors' market assessments and alternatives. However, the other
18 component of the DCF formula, investors' expectations regarding the future long-
19 run growth rate of dividends, is not readily apparent from stock market data and
20 must be estimated using informed judgment.

Q15. What is the appropriate DCF formula to use in this proceeding?

A15. 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 $(1 + 0.75g)$. Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by $(1 + 0.5g)$. 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:

$$K = \frac{D_0(1 + 0.625g)}{P} + g$$

Where:

$K =$ the cost of capital, or total return that investors expect to receive;

$P =$ the current market price of the stock;

$D_0 =$ 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.

1 D. Flotation Cost Adjustment

2 **Q16. Does the investor return requirement that is estimated by a DCF analysis need**
3 **to be adjusted for flotation costs in order to estimate the cost of capital?**

4 A16. Yes. There are significant costs associated with issuing new common equity
5 capital, and these costs must be considered in determining the cost of capital.
6 Schedule 2 of Exhibit No.___(JSG-2) shows a representative sample of flotation
7 costs incurred with 51 new common stock issues by electric utilities from January
8 2005 through November 2014. Flotation costs associated with these new issues
9 averaged 3.37 percent.

10 This indicates that in order to be able to issue new common stock on reasonable
11 terms, without diluting the value of the existing stockholders' investment,
12 Montana-Dakota must have an expected return that places a value on its equity that
13 is approximately 3.5 percent above book value. The cost of common equity capital
14 is therefore the investor return requirement multiplied by 1.035.

15 One purpose of a flotation cost adjustment is to compensate common equity
16 investors for past flotation costs by recognizing that their real investment in the
17 company exceeds the equity portion of the rate base by the amount of past flotation
18 costs. For example, the proxy companies generally have incurred flotation costs in
19 the past and, thus, the cost of capital invested in these companies is the investor
20 return requirement plus an adjustment for flotation costs. A more important
21 purpose of a flotation cost adjustment is to establish a return that is sufficient to
22 enable a company to attract capital on reasonable terms. This fundamental

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

9 E. DCF Study of Electric Utility Companies

10 **Q17. Would you please describe the overall approach used in your DCF analysis of**
11 **Montana-Dakota's cost of common equity for its Montana electric utility**
12 **operations?**

13 A17. Because Montana-Dakota's Montana electric utility operations must compete for
14 capital with many other potential projects and investments, it is essential that it have
15 an allowed return that matches returns potentially available from other similarly
16 risky investments. The DCF method provides a good measure of the returns
17 required by investors in the financial markets. However, the DCF method requires
18 a market price of common stock to compute the dividend yield component. Since
19 Montana-Dakota is a division of MDU Resources and does not have publicly-traded
20 common stock, a direct, market-based DCF analysis of Montana-Dakota's Montana
21 electric utility operations as a stand-alone company is not possible. As an
22 alternative, I have used a group of electric utilities that have publicly-traded

1 common stock as a proxy group for purposes of estimating the cost of common
2 equity for Montana-Dakota's Montana electric utility operations.

3 **Q18. How did you select a group of electric utility proxy companies?**

4 A18. I started with the 46 companies that Value Line classifies as Electric Utilities to
5 ensure that the company is considered to be primarily engaged in the electric utility
6 business and that retention growth rate projections are available. From that group,
7 I eliminated any companies that did not have investment-grade credit ratings from
8 either Standard & Poor's ("S&P") or Moody's Investors Service ("Moody's")
9 because such companies are not sufficiently comparable in terms of business and
10 financial risk to Montana-Dakota. In order to ensure that the company is primarily
11 engaged in the electric utility business, I eliminated any company that did not derive
12 at least 80 percent of its operating income from regulated electric utility operations
13 in 2014, or that did not have at least 80 percent of its total assets devoted to the
14 provision of electric utility service in 2014. Lastly, in order to ensure that the proxy
15 companies have risks that are most similar to those of Montana-Dakota I included
16 only companies that own a large share of their own generation and that also have
17 significant exposure to the risks of coal-fired generation. For example, Montana-
18 Dakota generated approximately 72% of its energy needs in 2014 and 92 percent
19 of its generation was from coal-fired power plants. In selecting proxy companies
20 for my analysis I excluded any company that did not produce at least 50.0 percent
21 of its energy requirements from company-owned generation in 2014 and that did
22 not use coal for at least 50.0 percent of its energy production in 2014. As shown

on page 1 of Schedule 3 of Exhibit No.___(JSG-2), 12 companies met these criteria for inclusion in the proxy group.

Q19. How did you calculate the dividend yields for the companies in your proxy group?

A19. These calculations are shown on pages 1 through 4 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 for each month during the six-month period from November 2014 through April 2015. The average monthly dividend yields were calculated for each company by dividing the prevailing annualized dividend for the period by the average of the stock prices for each month. These dividend yields were then multiplied by the quarterly DCF model factor ($1 + 0.625g$) to arrive at the projected dividend yield component of the DCF model.

Q20. Please describe the method you used to estimate the future growth rate that investors expect from this group of companies.

A20. 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 retention growth (also known as "sustainable growth") forecasts from Value Line forecasts of dividends, earnings, and returns on equity to derive the DCF rate of return estimate. As a second approach, I

1 conducted a Basic DCF analysis that relied on analysts' earnings forecasts for the
2 growth rate component of the model. My third approach used a combination of the
3 Value Line retention growth forecasts and analysts' earnings growth projections to
4 produce a Blended Growth Rate Analysis.

5 F. Retention Growth Analysis

6 **Q21. What approach did you use in calculating the long-term growth rate in your**
7 **Retention Growth DCF analysis?**

8 A21. In the Retention Growth DCF analysis, the long-term growth rate component is
9 based on the calculation of retention growth rates using Value Line forecasts for
10 each company. This Retention Growth DCF analysis better reflects investors'
11 inflation expectations and the real requirements for long-term investments in plant
12 under current market conditions.

13 **Q22. Please describe the Retention Growth rate component of your analysis.**

14 A22. I have relied upon Value Line projections of the retention growth rates that the
15 proxy companies are expected to begin maintaining three to five years in the future.
16 Although companies may experience extended periods of growth for other reasons,
17 in the long-run, growth in earnings and dividends per share depends in part on the
18 amount of earnings that is being retained and reinvested in a company. Thus, the
19 primary determinants of growth for the proxy companies will be (i) their ability to
20 find and develop profitable opportunities; (ii) their ability to generate profits that
21 can be reinvested in order to sustain growth; and, (iii) their willingness and
22 inclination to reinvest available profits. Expected future retention rates provide a

general measure of these determinants of expected growth, particularly items (ii) and (iii).

Q23. How can a company's earnings retention rate affect its future growth?

A23. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that is generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (b) by 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 12 percent and retain 75 percent of its earnings might be expected to have a growth rate of 9 percent, computed as follows:

$$0.75 \times 12\% = 9\%$$

On the other hand, another company that is also expected to earn 12 percent but only retains 25 percent of its earnings might be expected to have a growth rate of 3.0 percent, computed as follows:

$$0.25 \times 12\% = 3\%$$

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.

Q24. How did you calculate the expected future retention rates of the proxy companies?

A24. 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

three to five years in the future. Since these retention rates are projected to occur 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 three to five 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 5 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 is being retained and reinvested in the company. This earnings retention rate is multiplied by the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 3.97 percent.

Q25. How did you calculate the cost of capital using the Retention Growth DCF analysis?

A25. These calculations are shown on page 7 of Schedule 4 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied by the quarterly dividend adjustment factor ($1 + 0.625g$) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.035, to arrive at the Retention Growth DCF estimate of the cost of common equity capital for the proxy companies. The Retention Growth DCF analysis indicates a cost of common equity for the proxy

1 companies in a range from 6.65 percent to 10.08 percent. In this analysis, the
2 median for the group is 7.97 percent and the third quartile is 8.21 percent.

3 G. Basic DCF Analysis

4 **Q26. How did you estimate the expected future growth rate in your Basic DCF**
5 **analysis?**

6 A26. In my Basic DCF analysis, I have estimated expected future growth based on long-
7 term earnings per share growth rate forecasts of investment analysts, which are an
8 important source of information regarding investors' growth rate expectations.
9 This Basic DCF analysis assumes that the analysts' earnings growth forecasts
10 incorporate all information required to estimate a long-term expected growth rate
11 for a company. Zacks is a service that collects earnings growth estimates by
12 professional investment analysts and publishes a summary of the consensus
13 forecasts. In addition, Yahoo Finance also publishes earnings growth estimates
14 from investment analysts. I have used the average of Zacks and Yahoo's consensus
15 forecasts as the primary source for analysts' forecasts in my calculations. As shown
16 on page 6 of Schedule 4 of Exhibit No.___(JSG-2), the average of the analysts'
17 long-term earnings growth rate estimates for the electric utility proxy companies is
18 4.82 percent.

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

20 A27. These calculations are shown on page 8 of Schedule 4 of Exhibit No.___(JSG-2).
21 Again, the annual dividend yield is multiplied by the quarterly dividend adjustment
22 factor ($1 + 0.625g$) and this product is added to the growth rate estimate to arrive

at the investor-required return. Then, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.035, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a cost of common equity for the proxy companies in a range from 7.13 percent to 13.27 percent. In this analysis, the median for the group is 9.40 percent and the third quartile is 10.65 percent.

H. Blended Growth Rate Analysis

Q28. How did you use your Blended Growth Rate Analysis to estimate investors' long-term growth rate expectations for the proxy companies?

A28. The Blended Growth Rate approach combines: (i) Value Line retention growth forecasts; and (ii) estimates of long-term earnings growth for each company that are published by various investment analysts.

Q29. How did you utilize the analysts' projected earnings growth rates and the projected earnings retention growth rates in estimating expected growth for the proxy companies in the Blended Growth Rate Analysis?

A29. As shown on page 6 of Schedule 4 of Exhibit No.___(JSG-2), I calculated a weighted average of the analysts' projected earnings 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 one-half weighting to the analysts' earnings growth rate projections and one-half weighting to the projected retention growth rates. The average of the blended growth rates for the proxy companies is 4.82 percent and the median is 4.68 percent.

Q30. How did you utilize these Blended Growth Rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A30. These calculations are shown on page 9 of Schedule 4 of Exhibit No.___(JSG-2). Again, the annual dividend yield for each company is multiplied by the quarterly dividend adjustment factor ($1 + 0.625g$), and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.035, to arrive at the cost of common equity capital for the proxy companies. This Blended Growth Rate Analysis indicates that the cost of common equity capital for the electric utility proxy companies is in a range between 6.96 percent and 10.70 percent. In this analysis, the median for the group is 8.53 percent and the third quartile is 9.92 percent.

I. Risk Premium Analysis

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

A31. 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 subordinate to the claims of

1 bondholders. This priority standing provides bondholders with greater assurances
2 that they will receive the return on investment that they expect and that they will
3 receive a return of their investment when the bonds mature. Accompanying the
4 greater risk associated with common stocks is a requirement by investors that they
5 can expect to earn, on average, a return that is greater than the return they could
6 earn by investing in less risky bonds. Thus, the risk premium approach estimates
7 the return investors require from common stocks by utilizing current market
8 information that is readily available in bond yields and adding to those yields a
9 premium for the added risk of investing in common stocks.

10 Investors' expectations for the future are influenced to a large extent by their
11 knowledge of past experience. Ibbotson Associates annually publishes extensive
12 data regarding the returns that have been earned on stocks, bonds and U.S. Treasury
13 bills since 1926. Historically, the annual return on large company common stocks
14 has exceeded the return on long-term corporate bonds by a premium of 570 basis
15 points (5.7 percent) per year from 1926-2014.[22] When this premium is added to the
16 average yield on Moody's corporate bonds for the period from November 2014
17 through April 2015 of 4.02 percent[23], the result is an investor return requirement
18 for large company stocks of approximately 9.72 percent. However, investors in
19 smaller companies expect higher returns over the long-term, due to the additional
20 business and financial risks that smaller companies face. According to Ibbotson
21 Associates, companies in the same size range as Montana-Dakota's Montana

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22 Ibbotson SBBI 2015 Classic Yearbook, at 91. Calculation: (12.1 percent – 6.4 percent = 5.7 percent)

23 Exhibit No.___(JSG-2), Schedule 1, at 3.

electric distribution operations have had a premium of 1,420 basis points (14.2 percent) over the average return on long-term corporate bonds.[24] When added to the recent average corporate bond yield, this size-related premium suggests an expected return of 18.12 percent. This analysis indicates that the rate of return that I am proposing in this proceeding would be low relative to the historic risk premiums earned by similarly-sized unregulated companies.

J. Market DCF Analysis

Q32. What other analysis did you conduct in determining the cost of equity capital for Montana-Dakota?

A32. For an additional benchmark of the reasonableness of my DCF results, I calculated the current required return for the companies contained in the S&P 500. Using data provided by the Bloomberg Professional service, I performed a market capitalization-weighted DCF calculation on the S&P 500 companies based on the current dividend yields and long-term growth rate estimates as of April 30, 2015. These calculations are shown in Schedule 5 of Exhibit No.___(JSG-2). The current secondary market required ROE for the S&P 500 is 12.39 percent. This analysis indicates that the rate of return that I am proposing in this proceeding is low relative to the return required by investors who invest in the S&P 500.

[24] Ibbotson SBBI 2015 Classic Yearbook, at 91 and 109. Ibbotson Associates defines size ranges based on market capitalization. I calculated the implied market capitalization for Montana-Dakota's Montana electric distribution operations based on the Company's projected average rate base for 2015 ($87.0 million) and the projected average equity ratio for 2015 (49.52 percent). This places Montana-Dakota's Montana electric distribution operations in Ibbotson Associates' tenth decile. Calculation: 20.6 percent – 6.4 percent = 14.2 percent.

1 K. Relative Risk Analysis

2 **Q33. Have you compared the risks faced by Montana-Dakota's Montana electric**
3 **utility operations with the risks faced by the proxy group of companies?**

4 A33. Yes. There are four broad categories of risk that concern investors. These include:

5 1. Business Risk;
6 2. Regulatory Risk;
7 3. Financial Risk; and,
8 4. Market Risk.

9 **Q34. Please describe the business risks inherent in the electric utility industry.**

10 A34. Business risk refers to the ability of the firm to generate revenues that exceed its
11 cost of operations. Business risk exists because forecasts of both demand and costs
12 are inherently uncertain. Markets change and the level of demand for the firm's
13 output may be sufficient to cover its costs at one time and later become insufficient.
14 Sunk investments in long-lived electric utility assets, for which cost recovery
15 occurs over a period of thirty years or more, are subject to enormous uncertainties
16 and risks that demand, costs, supply, and competition may change in ways that
17 adversely affect the value of the investment.

18 **Q35. Is it appropriate to evaluate the risks of Montana-Dakota's Montana electric**
19 **utility operations on a stand-alone basis for ratemaking purposes?**

20 A35. Yes. The stand-alone principle is widely-recognized in public utility regulation.
21 This is the principle that regulated rates and the allowed rate of return should be set
22 at a level that reflects the risks and investment characteristics of the regulated entity
23 alone, as if it has no affiliates. If a parent company has greater risks, or lesser risks,
24 than the regulated company, that fact should not affect the allowed rate of return.

1 Similarly, the risks and financial positions of the parent, affiliates, subsidiaries or
2 other jurisdictions of the regulated company should not be considered in setting
3 rates for a regulated company. Many regulators have adopted the stand-alone
4 principle in part to insulate ratepayers from the higher risks associated with possibly
5 higher risk activities of the non-jurisdictional operations of a holding company.

6 In this case, the equity capital used to finance MDU's regulated electric utility
7 operations in Montana is obtained from the parent company, MDU Resources
8 Group. However, these operations must compete for equity capital with other
9 divisions and jurisdictions within the MDU organization, and therefore must offer a
10 return that is comparable to and competitive with the return available to utilities with
11 levels of risk that are commensurate with the risk of the Montana electric operations
12 on a stand-alone basis. For these reasons, Montana-Dakota's Montana electric
13 operation should be evaluated as a stand-alone entity.

14 **Q36. What are some of the business risks faced by Montana-Dakota's Montana**
15 **electric utility operations?**

16 A36. The Company's electric utility operations in Montana face many of the same
17 business risks that are associated with other electric utilities. However, as shown on
18 page 1 of Schedule 3 of Exhibit No.___(JSG-2), Montana-Dakota's Montana
19 electric utility operations are considerably smaller than the operations of any of the
20 proxy companies and a small fraction of the size of the typical proxy company. For
21 example, Montana-Dakota's Montana electric utility total assets are equal to only
22 2.38 percent of the assets of the median proxy company. Similarly, Montana-
23 Dakota's Montana electric utility operating revenues and operating income are only

2.57 percent and 1.34 percent of the level for the median proxy company, respectively. Thus, depending upon the measure of size, the typical proxy company is somewhere between 40 and 75 times the size of Montana-Dakota's Montana electric utility operations. The Company's smaller size has significant implications for business risks. As noted earlier, Ibbotson Associates has documented the significantly higher returns that have been associated with small companies. Considering only its smaller size, Montana-Dakota's Montana electric utility operations might require a return that is more than 100 basis points higher than the return required for the typical proxy company.

In addition, Montana-Dakota's generation portfolio is heavily reliant on coal. In 2014, 92 percent of its generation was fueled by coal. Montana-Dakota has the highest proportion of coal-fired generation of my entire proxy group of electric distribution companies. Utilities with generation that is heavily weighted toward one fuel source face greater risks that adverse circumstances will arise that render much 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. In June, 2014 the Environmental Protection Agency proposed the Clean Power Plan, which is a plan to cut emissions from existing power plants. Complying with this regulation poses additional business risk as sizable future capital expenditures may be required. This burden could weigh heavily on companies like Montana-Dakota that own a significant amount of coal-fired generation assets.

In addition, as natural gas prices remain at historically low levels, coal-fired generation faces an increased risk of becoming uneconomic. In fact, most new generation constructed in recent years has been fueled with natural gas as a result of low natural gas prices and new generating technologies, or wind power due to various subsidies and mandates for renewable generating technologies.

Q37. What are the regulatory risks faced by Montana-Dakota's Montana electric utility operations?

A37. 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'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 for 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.

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.

The regulatory environment can significantly affect both the access to, and cost of capital in several ways. As noted by Moody's, "the predictability and supportiveness of the regulatory framework in which it [a regulated utility] operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors."[25] Moody's further noted that:

> Utility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.[26]

Regulatory Research Associates assigns a rating of Below Average / 1 to the Montana Public Service Commission. This rating suggests above average regulatory risk for Montana-Dakota's Montana electric utility operations.

Q38. Would you please describe Montana-Dakota's relative financial risks?

A38. Financial risk exists to the extent that 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

[25] Moody's Investors Service, *Regulated Electric and Gas Utilities*, December 23, 2013, at 9.
[26] *Ibid.*

1 magnify the effects of business and regulatory risks. Fixed financial obligations
2 also increase the probability of bankruptcy by reducing the company's financial
3 flexibility and ability to respond to adverse circumstances. One possible indicator
4 of investors' perceptions of relative financial risk in this case might be obtained
5 from credit ratings. Because Montana-Dakota, as a division of MDU Resources,
6 does not have its own bonds outstanding, it is difficult to make direct comparisons
7 between the ratings of Montana-Dakota and the proxy group. However, page 2 of
8 Schedule 3 of Exhibit No.___(JSG-2) shows the credit ratings assigned by S&P and
9 Moody's to each of the companies in the comparison group and MDU Resources.

10 The median S&P credit rating for companies in the proxy group is BBB+. By
11 comparison, MDU Resources' senior unsecured debt also carries an S&P rating of
12 BBB+. This suggests that the perceived business and financial risk of MDU
13 Resources' bonds is equal to that of the typical company in the comparison group.

14 The capital structure data on Schedule 6 of Exhibit No.___(JSG-2) show that
15 Montana-Dakota's filed common equity ratio of 49.52 percent is slightly greater
16 than, but close to, the 47.08 percent median for the proxy companies as of March
17 31, 2015. This approximately average common equity ratio, suggests average
18 financial risk for Montana-Dakota's Montana electric utility operations.

19 **Q39. Would you please describe Montana-Dakota's market risks?**

20 A39. Market risk is associated with the changing value of all investments because of
21 business cycles, inflation, and fluctuations in the general cost of capital throughout
22 the economy. Different companies are subject to different degrees of market risk

largely as a result of differences in their business and financial risks. Overall, the market risk of Montana-Dakota's Montana electric utility business is comparable to that of the companies in the electric utility comparison group.

Q40. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's Montana electric utility operations?

A40. Montana-Dakota's Montana electric utility operations face overall risks that are near the top of the range relative to those of the proxy companies. Although it has financial risks that are average relative to the proxy companies, Montana-Dakota's Montana electric utility operations have business risks that are well above average due to its exceptionally small size and its greater reliance on coal-fired generation than all of the proxy companies. These considerations lead me to conclude that investors appraise the overall risks of Montana-Dakota's Montana electric utility operations to be above average relative to those of the proxy companies. Consequently, Montana-Dakota's Montana electric utility business requires an allowed rate of return that is in the upper portion of the range for the companies in the proxy group indicated by my DCF analyses.

III. SUMMARY AND CONCLUSIONS

Q41. Please summarize the results of your cost of capital study.

A41. I conducted three DCF analyses on a group of electric utilities that have a range of risks that is roughly comparable to those of Montana-Dakota's Montana electric utility operations. These results are summarized as follows:

Table 3: Summary of DCF Results

	Retention Growth DCF Analysis	Basic DCF Analysis	Blended Growth Rate DCF Analysis
High	10.08%	13.27%	10.70%
3rd Quartile	8.21%	10.65%	9.92%
Median	**7.97%**	**9.40%**	**8.53%**
1st Quartile	7.44%	8.34%	8.13%
Low	6.65%	7.13%	6.96%

In addition, I conducted two risk premium analyses and a market DCF analysis of the S&P 500 to test the reasonableness of my DCF analyses. Those results are summarized as follows:

Table 4: Benchmark Risk Premium and Market DCF Analyses

	Return
Risk Premium (Long-Term Corporate Bonds)	
vs. Large Company Stocks	9.7%
vs. Small Company Stocks	18.2%
Market DCF (S&P 500)	12.4%

In developing my recommendation, I have given greater weight to analysts' earnings growth forecasts and the Basic DCF analysis. Because projected retention growth is sustainable indefinitely and 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.

1 My risk premium and market DCF analyses suggest that the DCF results generally
2 are low relative to current market benchmarks. In particular, all of the DCF return
3 estimates are considerably below the 18.2 percent risk premium return benchmark
4 for companies in Montana-Dakota's relative size range. Similarly, the DCF
5 estimates for the electric utility proxy companies are well below the 12.4 percent
6 market DCF estimate for the S&P 500 companies.

7 **Q42. What rate of return on common equity do you recommend for Montana-**
8 **Dakota's Montana electric utility operations in this proceeding?**

9 A42. My analyses indicate that an appropriate rate of return on common equity for
10 Montana-Dakota's Montana electric utility operations at this time is 10.00 percent,
11 which is above the median, but below the third quartile of the range for my Basic
12 DCF analysis. It is also below the top of the range for each of the DCF analyses.
13 This recommended return reflects my assessment that the overall risks of Montana-
14 Dakota's Montana electric utility operations are above average relative to those of
15 the proxy companies. Although the Company has average financial risks relative
16 to the proxy companies, it has business risks that are well above average. In
17 addition to its exceptionally small size relative to the proxy companies, Montana-
18 Dakota's Montana electric utility operations are more heavily reliant on coal-fired
19 generation than all but one of the proxy companies and the economics of coal-fired
20 generation is threatened by proposed environmental regulations and other federal
21 initiatives. Thus, my recommended return is appropriately positioned to reflect the
22 current risks faced by Montana-Dakota's Montana electric utility operations
23 relative to the risks faced by the proxy companies.

Q43. Does this conclude your Prepared Direct Testimony?

A43. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1984-2014

	[1]	[2]	[3]	[4]	[5]
	Percentage Price Changes				
Year	Consumer Price Index	GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP ($ billions)	Nominal GDP Growth
1984	4.3%	3.5%	7.3%	4,040.7	
1985	3.6%	3.2%	4.2%	4,346.7	7.6%
1986	1.9%	2.0%	3.5%	4,590.2	5.6%
1987	3.6%	2.6%	3.5%	4,870.2	6.1%
1988	4.1%	3.5%	4.2%	5,252.6	7.9%
1989	4.8%	3.9%	3.7%	5,657.7	7.7%
1990	5.4%	3.7%	1.9%	5,979.6	5.7%
1991	4.2%	3.3%	-0.1%	6,174.0	3.3%
1992	3.0%	2.3%	3.6%	6,539.3	5.9%
1993	3.0%	2.4%	2.7%	6,878.7	5.2%
1994	2.6%	2.1%	4.0%	7,308.8	6.3%
1995	2.8%	2.1%	2.7%	7,664.1	4.9%
1996	3.0%	1.8%	3.8%	8,100.2	5.7%
1997	2.3%	1.7%	4.5%	8,608.5	6.3%
1998	1.6%	1.1%	4.5%	9,089.2	5.6%
1999	2.2%	1.5%	4.7%	9,660.6	6.3%
2000	3.4%	2.3%	4.1%	10,284.8	6.5%
2001	2.8%	2.3%	1.0%	10,621.8	3.3%
2002	1.6%	1.5%	1.8%	10,977.5	3.3%
2003	2.3%	2.0%	2.8%	11,510.7	4.9%
2004	2.7%	2.7%	3.8%	12,274.9	6.6%
2005	3.4%	3.2%	3.3%	13,093.7	6.7%
2006	3.2%	3.1%	2.7%	13,855.9	5.8%
2007	2.8%	2.7%	1.8%	14,477.6	4.5%
2008	3.8%	2.0%	-0.3%	14,718.6	1.7%
2009	-0.4%	0.8%	-2.8%	14,418.7	-2.0%
2010	1.6%	1.2%	2.5%	14,964.4	3.8%
2011	3.2%	2.1%	1.6%	15,517.9	3.7%
2012	2.1%	1.8%	2.3%	16,163.2	4.2%
2013	1.5%	1.5%	2.2%	16,768.1	3.7%
2014	1.6%	1.4%	2.4%	17,420.7	3.9%
Average Rate of Change [6]:					
1984-2014	2.8%	2.3%	2.7%	5.0%	5.0%
1994-2014	2.4%	1.9%	2.5%	4.4%	4.5%
2004-2014	2.3%	2.0%	1.6%	3.6%	3.6%

Notes:
[1] U.S. Department of Labor, Bureau of Labor Statistics;
[1] U.S. city average, all urban consumers, all items, not seasonally adjusted
[2] U.S. Department of Commerce, Bureau of Economic Analysis,
[2] National Income and Product Accounts Tables, Table 1.1.9, Revised on April 29, 2015
[3] U.S. Department of Commerce, Bureau of Economic Analysis,
[3] National Income and Product Accounts Tables, Table 1.1.1, Revised on April 29, 2015
[4] U.S. Department of Commerce, Bureau of Economic Analysis,
[4] National Income and Product Accounts Tables, Table 1.1.5, Revised on April 29, 2015
[5] Equals annual percent change of Column [4]
[6] Nominal GDP growth rates based on geometric average rate of change

Montana-Dakota Utilities Co.

Bond Yield Averages

January 2007 - April 2015

		[1]	[2]	[3]	[4]	[5]	[6]
		30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds		Credit Spreads	
				A-Rated	Baa-Rated	A-Rated	Baa-Rated
2007	JAN	4.85	5.92	5.96	6.16	1.10	1.31
	FEB	4.82	5.88	5.90	6.10	1.08	1.28
	MAR	4.72	5.84	5.85	6.10	1.13	1.38
	APR	4.87	5.99	5.97	6.24	1.10	1.37
	MAY	4.90	6.00	5.99	6.23	1.08	1.33
	JUN	5.20	6.32	6.30	6.54	1.10	1.34
	JUL	5.11	6.26	6.25	6.49	1.14	1.38
	AUG	4.93	6.26	6.24	6.51	1.30	1.58
	SEP	4.79	6.21	6.18	6.45	1.39	1.66
	OCT	4.77	6.12	6.11	6.36	1.34	1.59
	NOV	4.52	5.97	5.97	6.27	1.45	1.75
	DEC	4.53	6.15	6.16	6.51	1.63	1.98
2008	JAN	4.33	6.02	6.02	6.35	1.68	2.01
	FEB	4.51	6.24	6.21	6.60	1.70	2.08
	MAR	4.38	6.23	6.21	6.68	1.83	2.30
	APR	4.44	6.29	6.29	6.81	1.85	2.37
	MAY	4.60	6.31	6.28	6.79	1.68	2.20
	JUN	4.68	6.43	6.38	6.93	1.70	2.24
	JUL	4.56	6.44	6.40	6.97	1.84	2.41
	AUG	4.50	6.42	6.37	6.98	1.87	2.48
	SEP	4.27	6.50	6.49	7.15	2.22	2.88
	OCT	4.16	7.56	7.56	8.58	3.40	4.42
	NOV	3.98	7.65	7.60	8.98	3.62	5.00
	DEC	2.85	6.71	6.52	8.11	3.68	5.27
2009	JAN	3.10	6.59	6.39	7.90	3.29	4.80
	FEB	3.59	6.64	6.30	7.74	2.71	4.15
	MAR	3.64	6.84	6.42	8.00	2.79	4.36
	APR	3.76	6.85	6.48	8.03	2.73	4.27
	MAY	4.24	6.79	6.49	7.76	2.25	3.52
	JUN	4.51	6.52	6.20	7.30	1.69	2.79
	JUL	4.40	6.17	5.97	6.87	1.56	2.47
	AUG	4.37	5.83	5.71	6.36	1.34	1.99
	SEP	4.19	5.61	5.53	6.12	1.34	1.93
	OCT	4.19	5.63	5.55	6.14	1.36	1.95
	NOV	4.31	5.68	5.63	6.17	1.32	1.86
	DEC	4.50	5.78	5.79	6.26	1.29	1.76
2010	JAN	4.60	5.76	5.77	6.16	1.17	1.55
	FEB	4.62	5.86	5.87	6.25	1.25	1.63
	MAR	4.65	5.81	5.84	6.22	1.20	1.58
	APR	4.69	5.80	5.81	6.19	1.12	1.50
	MAY	4.28	5.52	5.50	5.97	1.22	1.69
	JUN	4.12	5.52	5.46	6.18	1.34	2.06
	JUL	3.99	5.32	5.26	5.98	1.27	1.99
	AUG	3.80	5.05	5.01	5.55	1.21	1.75
	SEP	3.77	5.05	5.01	5.53	1.23	1.76
	OCT	3.87	5.15	5.10	5.62	1.24	1.75
	NOV	4.19	5.37	5.37	5.85	1.18	1.66
	DEC	4.42	5.55	5.56	6.04	1.14	1.62

Montana-Dakota Utilities Co.

Bond Yield Averages

January 2007 - April 2015

		[1]	[2]	[3]	[4]	[5]	[6]
		30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds A-Rated	Public Utility Bonds Baa-Rated	Credit Spreads A-Rated	Credit Spreads Baa-Rated
2011	JAN	4.52	5.56	5.57	6.06	1.05	1.54
	FEB	4.65	5.66	5.68	6.10	1.03	1.45
	MAR	4.51	5.55	5.56	5.97	1.05	1.46
	APR	4.50	5.56	5.55	5.98	1.05	1.48
	MAY	4.29	5.33	5.32	5.74	1.03	1.45
	JUN	4.23	5.30	5.26	5.67	1.03	1.44
	JUL	4.28	5.30	5.27	5.70	0.99	1.42
	AUG	3.65	4.79	4.69	5.22	1.04	1.57
	SEP	3.18	4.60	4.48	5.11	1.30	1.93
	OCT	3.12	4.60	4.52	5.24	1.39	2.12
	NOV	3.01	4.39	4.25	4.93	1.24	1.92
	DEC	2.99	4.47	4.33	5.07	1.35	2.08
2012	JAN	3.01	4.45	4.34	5.06	1.32	2.05
	FEB	3.11	4.42	4.36	5.02	1.25	1.91
	MAR	3.28	4.54	4.48	5.13	1.20	1.85
	APR	3.18	4.49	4.40	5.11	1.21	1.93
	MAY	2.92	4.33	4.20	4.97	1.28	2.04
	JUN	2.70	4.22	4.08	4.91	1.39	2.21
	JUL	2.60	4.03	3.93	4.85	1.33	2.25
	AUG	2.77	4.09	4.00	4.88	1.23	2.11
	SEP	2.87	4.09	4.02	4.81	1.16	1.94
	OCT	2.91	3.97	3.91	4.54	1.01	1.64
	NOV	2.80	3.92	3.84	4.42	1.04	1.61
	DEC	2.89	4.05	4.00	4.56	1.11	1.67
2013	JAN	3.07	4.19	4.15	4.66	1.07	1.59
	FEB	3.16	4.27	4.18	4.74	1.02	1.58
	MAR	3.16	4.29	4.20	4.72	1.04	1.56
	APR	2.93	4.07	4.00	4.49	1.07	1.56
	MAY	3.11	4.23	4.17	4.65	1.05	1.54
	JUN	3.40	4.63	4.53	5.08	1.13	1.68
	JUL	3.60	4.76	4.68	5.21	1.08	1.61
	AUG	3.76	4.89	4.73	5.28	0.97	1.52
	SEP	3.78	4.95	4.80	5.31	1.02	1.52
	OCT	3.68	4.82	4.70	5.17	1.02	1.49
	NOV	3.80	4.91	4.77	5.24	0.97	1.44
	DEC	3.89	4.92	4.81	5.25	0.92	1.36
2014	JAN	3.77	4.76	4.63	5.09	0.86	1.32
	FEB	3.66	4.68	4.53	5.01	0.87	1.35
	MAR	3.62	4.65	4.51	5.00	0.89	1.37
	APR	3.52	4.52	4.41	4.85	0.89	1.33
	MAY	3.39	4.38	4.26	4.69	0.87	1.30
	JUN	3.42	4.44	4.29	4.73	0.87	1.31
	JUL	3.33	4.37	4.23	4.66	0.89	1.33
	AUG	3.20	4.29	4.13	4.65	0.93	1.45
	SEP	3.26	4.39	4.24	4.79	0.98	1.53
	OCT	3.04	4.22	4.06	4.67	1.02	1.63
	NOV	3.04	4.28	4.09	4.75	1.05	1.71
	DEC	2.83	4.17	3.95	4.70	1.11	1.86
2015	JAN	2.46	3.84	3.58	4.39	1.13	1.94
	FEB	2.57	3.93	3.67	4.44	1.11	1.87
	MAR	2.63	3.98	3.74	4.51	1.12	1.88
	APR	2.59	3.93	3.75	4.51	1.16	1.92
2015	AVG	2.56	3.92	3.69	4.46	1.13	1.90

Notes:

[1] Bloomberg Finance L.P., 30-Year U.S. Treasury Bond

[2] Bloomberg Finance L.P., Moody's Average Corporate Bond Index

[3] Bloomberg Finance L.P., Moody's A-Rated Utility Bond Index

Montana-Dakota Utilities Co.

Bond Yield Averages

January 2007 - April 2015

	[1]	[2]	[3]	[4]	[5]	[6]
	30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds		Credit Spreads	
			A-Rated	Baa-Rated	A-Rated	Baa-Rated

[4] Bloomberg Finance L.P., Moody's Baa-Rated Utility Bond Index
[5] Equals Column [3] – Column [1]
[6] Equals Column [4] – Column [1]

Montana-Dakota Utilities Co.

Common Equity Flotation Costs of Electric Distribution Companies

2005-2015

Issuer	Date of Offering	Number of Shares	Issue Price	Gross Spread	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
ALLETE, Inc.	2/26/2014	3,220,000	49.7500	1.74	$48.009	3.63%
Exelon Corporation	6/11/2014	57,500,000	35.0000	1.05	$33.950	3.09%
NorthWestern Corporation	11/4/2014	7,766,990	51.5000	1.80	$49.698	3.63%
TECO Energy, Inc.	7/1/2014	16,700,000	18.1000	0.61	$17.489	3.49%
Hawaiian Electric Industries, Inc.	3/19/2013	7,000,000	26.7500	1.00	$25.747	3.90%
PG&E Corporation	2/27/2013	7,200,000	41.7100	0.05	$41.660	0.12%
Portland General Electric Company	6/11/2013	12,765,000	29.5000	0.96	$28.541	3.36%
UIL Holdings Corporation	9/26/2013	5,750,000	37.2500	1.30	$35.946	3.63%
Westar Energy, Inc.	9/24/2013	8,916,000	31.1500	1.09	$30.060	3.63%
Pepco Holdings, Inc.	3/5/2012	17,922,077	19.2500	0.67	$18.576	3.63%
PG&E Corporation	3/15/2012	5,900,000	43.0900	0.08	$43.010	0.19%
PPL Corporation	4/11/2011	92,000,000	25.3000	0.76	$24.541	3.09%
Black Hills Corporation	11/10/2010	4,413,519	29.7500	1.04	$28.709	3.63%
CenterPoint Energy, Inc.	6/9/2010	25,300,000	12.9000	0.45	$12.449	3.63%
Pinnacle West Capital Corporation	4/8/2010	6,900,000	38.0000	1.33	$36.670	3.63%
PPL Corporation	6/22/2010	103,500,000	24.0000	0.72	$23.280	3.09%
SCANA Corporation	5/11/2010	8,222,500	37.0000	1.30	$35.705	3.63%
UIL Holdings Corporation	9/16/2010	20,355,000	25.7500	1.09	$24.656	4.44%
Westar Energy, Inc.	11/4/2010	8,625,000	25.5400	0.89	$24.646	3.63%
Xcel Energy Inc.	8/3/2010	21,850,000	21.5000	0.65	$20.855	3.09%
Ameren Corporation	9/9/2009	21,850,000	25.2500	0.76	$24.493	3.09%
American Electric Power Company, Inc.	4/1/2009	69,000,000	24.5000	0.74	$23.765	3.09%
CenterPoint Energy, Inc.	9/10/2009	24,150,000	12.0000	0.42	$11.580	3.63%
Eversource Energy	3/16/2009	18,975,000	20.2000	0.66	$19.544	3.36%
Great Plains Energy Inc.	5/12/2009	11,500,000	14.0000	0.49	$13.510	3.63%
Portland General Electric Company	3/5/2009	12,477,500	14.1000	0.49	$13.607	3.63%
UIL Holdings Corporation	5/20/2009	4,600,000	21.0000	1.05	$19.950	5.26%
Hawaiian Electric Industries, Inc.	12/2/2008	5,000,000	23.0000	0.86	$22.138	3.90%
ITC Holdings Corp.	1/18/2008	6,420,737	50.1500	2.13	$48.019	4.44%
Otter Tail Corporation	9/18/2008	5,175,000	30.0000	1.09	$28.913	3.76%
Pepco Holdings, Inc.	11/6/2008	16,100,000	16.5000	0.62	$15.881	3.90%
SCANA Corporation	12/31/2008	2,875,000	35.5000	0.53	$34.968	1.52%
Westar Energy, Inc.	5/29/2008	6,000,000	24.2800	0.85	$23.430	3.63%
Consolidated Edison, Inc.	5/10/2007	11,000,000	50.7800	0.05	$50.730	0.10%
Empire District Electric Company	12/6/2007	3,000,000	23.0000	0.98	$22.023	4.44%
Portland General Electric Company	6/12/2007	23,658,106	26.0000	0.78	$25.220	3.09%
Vectren Corporation	2/22/2007	4,600,000	28.3300	0.99	$27.340	3.62%
Westar Energy, Inc.	11/15/2007	8,215,000	25.2500	0.88	$24.366	3.63%
Avista Corporation	12/12/2006	3,162,500	25.0500	0.48	$24.570	1.95%
Cleco Corporation	8/14/2006	6,900,000	23.7500	0.89	$22.860	3.89%
Consolidated Edison, Inc.	9/20/2006	9,715,000	46.1000	0.14	$45.960	0.30%
Empire District Electric Company	6/15/2006	3,795,000	20.2500	0.86	$19.390	4.44%
Great Plains Energy Inc.	5/18/2006	7,002,450	27.5000	0.89	$26.606	3.36%
ITC Holdings Corp.	10/4/2006	12,937,500	31.9100	1.44	$30.474	4.71%
PNM Resources, Inc.	12/6/2006	5,750,000	30.7900	1.08	$29.712	3.63%
CMS Energy Corporation	3/30/2005	23,000,000	12.2500	0.43	$11.821	3.63%
Eversource Energy	12/6/2005	23,000,000	19.0900	0.62	$18.470	3.36%
Integrys Energy Group, Inc.	11/15/2005	1,900,000	53.7000	1.75	$51.955	3.36%
ITC Holdings Corp.	7/25/2005	14,375,000	23.0000	1.44	$21.562	6.67%
Pinnacle West Capital Corporation	4/27/2005	6,095,000	42.0000	1.37	$40.635	3.36%
PNM Resources, Inc.	3/23/2005	3,910,000	26.7600	0.87	$25.890	3.36%
			Average 2005-2015:			**3.37%**
			Selected Flotation Costs for Cost of Equity:			**3.50%**

Sources: SNL Financial

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Fiscal Year 2014 Operating Data

Company	Ticker	Total Assets ($million)	Operating Revenues ($million)	Operating Income ($million)
ALLETE, Inc.	ALE	$4,361	$1,137	$189 1/
Alliant Energy Corporation	LNT	$12,086	$3,350	$544 1/
Ameren Corporation	AEE	$22,676	$6,053	$1,254 1/
American Electric Power Company, Inc.	AEP	$59,633	$17,020	$3,232 1/
Empire District Electric Company	EDE	$2,390	$652	$100 1/
Great Plains Energy Inc.	GXP	$10,476	$2,568	$535 1/
OGE Energy Corporation	OGE	$9,528	$2,453	$537 1/
Otter Tail Corporation	OTTR	$1,791	$803	$100 1/
PNM Resources, Inc.	PNM	$5,829	$1,436	$300 1/
TECO Energy, Inc.	TE	$8,726	$2,566	$505 1/
Westar Energy, Inc.	WR	$10,347	$2,602	$633 1/
Xcel Energy Inc.	XEL	$36,958	$11,686	$1,948 1/
High		$59,633	$17,020	$3,232
Average		**$15,400**	**$4,361**	**$823**
Median		**$9,937**	**$2,567**	**$536**
Low		$1,791	$652	$100
Montana-Dakota Utilities Co.				
- Montana Electric Distribution Division		**$236.5** 2/	**$58.2** 3/	**$7.2** 3/
MDU Resources Group, Inc.		$7,810 1/	$4,671 1/	$488 1/
Montana-Dakota Montana Electric Distribution % of:				
- Proxy Company Median		2.38%	2.27%	1.34%
- MDU Resources Group, Inc.		3.03%	1.25%	1.47%

Notes:
1/ Source: SNL Financial LC; data as of December 31, 2014
2/ Rate Base Statement 12 months ended December 2014 Pro Forma

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Credit Ratings

Company	Ticker	Standard & Poor's	Moody's
ALLETE, Inc.	ALE	BBB+	A3
Alliant Energy Corporation	LNT	A-	A3
Ameren Corporation	AEE	BBB+	Baa1
American Electric Power Company, Inc.	AEP	BBB	Baa1
Empire District Electric Company	EDE	BBB	Baa1
Great Plains Energy Inc.	GXP	BBB+	Baa2
OGE Energy Corporation	OGE	A-	A3
Otter Tail Corporation	OTTR	BBB	Baa2
PNM Resources, Inc.	PNM	BBB	Baa3
TECO Energy, Inc.	TE	BBB+	Baa1
Westar Energy, Inc.	WR	BBB+	Baa1
Xcel Energy Inc.	XEL	A-	A3
Average		**BBB+**	**Baa1**
Median		**BBB+**	**Baa1**
MDU Resources Group, Inc.		BBB+	-

Notes:
Source: SNL Financial LC as of May 6, 2015.

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Dividend Yields
November 2014 - April 2015

Company	Ticker	Average Dividend Yield
ALLETE, Inc.	ALE	3.71%
Alliant Energy Corporation	LNT	3.34%
Ameren Corporation	AEE	3.76%
American Electric Power Company, Inc.	AEP	3.60%
Empire District Electric Company	EDE	3.82%
Great Plains Energy Inc.	GXP	3.58%
OGE Energy Corporation	OGE	2.94%
Otter Tail Corporation	OTTR	3.91%
PNM Resources, Inc.	PNM	2.68%
TECO Energy, Inc.	TE	4.45%
Westar Energy, Inc.	WR	3.56%
Xcel Energy Inc.	XEL	3.49%
Average		**3.57%**
Median		**3.59%**

			Price			Annualized	Dividend
			Low	High	Average	Dividend	Yield
ALLETE, Inc.	ALE	Nov-14	$ 49.56	$ 53.26	$ 51.41	$ 1.96	3.81%
		Dec-14	50.49	57.97	54.23	1.96	3.61%
		Jan-15	54.30	59.73	57.02	1.96	3.44%
		Feb-15	52.38	57.77	55.07	2.02	3.67%
		Mar-15	51.16	54.90	53.03	2.02	3.81%
		Apr-15	49.84	52.98	51.41	2.02	3.93%
							3.71%
Alliant Energy Corporation	LNT	Nov-14	$ 61.35	$ 63.73	$ 62.54	$ 2.04	3.26%
		Dec-14	61.94	69.78	65.86	2.04	3.10%
		Jan-15	65.30	70.80	68.05	2.20	3.23%
		Feb-15	62.89	69.35	66.12	2.20	3.33%
		Mar-15	59.92	63.92	61.92	2.20	3.55%
		Apr-15	60.20	64.14	62.17	2.20	3.54%
							3.34%
Ameren Corporation	AEE	Nov-14	$ 41.89	$ 44.22	$ 43.06	$ 1.60	3.72%
		Dec-14	42.15	48.14	45.15	1.64	3.63%
		Jan-15	44.64	46.81	45.72	1.64	3.59%
		Feb-15	41.14	45.66	43.40	1.64	3.78%
		Mar-15	40.51	43.12	41.81	1.64	3.92%
		Apr-15	40.68	43.00	41.84	1.64	3.92%
							3.76%

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Dividend Yields
November 2014 - April 2015

Company	Ticker	Average Dividend Yield
ALLETE, Inc.	ALE	3.71%
Alliant Energy Corporation	LNT	3.34%
Ameren Corporation	AEE	3.76%
American Electric Power Company, Inc.	AEP	3.60%
Empire District Electric Company	EDE	3.82%
Great Plains Energy Inc.	GXP	3.58%
OGE Energy Corporation	OGE	2.94%
Otter Tail Corporation	OTTR	3.91%
PNM Resources, Inc.	PNM	2.68%
TECO Energy, Inc.	TE	4.45%
Westar Energy, Inc.	WR	3.56%
Xcel Energy Inc.	XEL	3.49%
Average		**3.57%**
Median		**3.59%**

			Price			Annualized	Dividend
			Low	High	Average	Dividend	Yield
American Electric Power Company, Inc.	AEP	Nov-14	$ 55.90	$ 59.84	$ 57.87	$ 2.12	3.66%
		Dec-14	56.97	63.22	60.10	2.12	3.53%
		Jan-15	59.97	65.38	62.68	2.12	3.38%
		Feb-15	57.01	63.51	60.26	2.12	3.52%
		Mar-15	54.66	58.28	56.47	2.12	3.75%
		Apr-15	55.38	58.35	56.87	2.12	3.73%
							3.60%
Empire District Electric Company	EDE	Nov-14	$ 27.52	$ 28.87	$ 28.20	$ 1.04	3.69%
		Dec-14	27.40	31.20	29.30	1.04	3.55%
		Jan-15	29.16	31.49	30.33	1.04	3.43%
		Feb-15	24.33	30.94	27.64	1.04	3.76%
		Mar-15	23.67	25.57	24.62	1.04	4.22%
		Apr-15	23.47	25.41	24.44	1.04	4.26%
							3.82%
Great Plains Energy Inc.	GXP	Nov-14	$ 25.63	$ 27.38	$ 26.51	$ 0.98	3.70%
		Dec-14	25.94	29.46	27.70	0.98	3.54%
		Jan-15	27.43	30.25	28.84	0.98	3.40%
		Feb-15	26.31	29.65	27.98	0.98	3.50%
		Mar-15	25.58	27.31	26.45	0.98	3.71%
		Apr-15	26.03	27.63	26.83	0.98	3.65%
							3.58%
OGE Energy Corporation	OGE	Nov-14	$ 35.64	$ 37.90	$ 36.77	$ 1.00	2.72%
		Dec-14	32.85	36.70	34.78	1.00	2.88%
		Jan-15	33.44	36.48	34.96	1.00	2.86%
		Feb-15	32.12	35.75	33.94	1.00	2.95%
		Mar-15	30.82	32.60	31.71	1.00	3.15%
		Apr-15	31.34	33.21	32.28	1.00	3.10%
							2.94%

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Dividend Yields
November 2014 - April 2015

Company	Ticker	Average Dividend Yield
ALLETE, Inc.	ALE	3.71%
Alliant Energy Corporation	LNT	3.34%
Ameren Corporation	AEE	3.76%
American Electric Power Company, Inc.	AEP	3.60%
Empire District Electric Company	EDE	3.82%
Great Plains Energy Inc.	GXP	3.58%
OGE Energy Corporation	OGE	2.94%
Otter Tail Corporation	OTTR	3.91%
PNM Resources, Inc.	PNM	2.68%
TECO Energy, Inc.	TE	4.45%
Westar Energy, Inc.	WR	3.56%
Xcel Energy Inc.	XEL	3.49%
Average		**3.57%**
Median		**3.59%**

			Price			Annualized	Dividend
			Low	High	Average	Dividend	Yield
Otter Tail Corporation	OTTR	Nov-14	$ 28.66	$ 31.40	$ 30.03	$ 1.21	4.03%
		Dec-14	28.40	32.72	30.56	1.21	3.96%
		Jan-15	30.60	32.16	31.38	1.21	3.86%
		Feb-15	30.81	33.24	32.03	1.23	3.84%
		Mar-15	31.06	33.44	32.25	1.23	3.81%
		Apr-15	29.80	32.76	31.28	1.23	3.93%
							3.91%
PNM Resources, Inc.	PNM	Nov-14	$ 28.19	$ 29.62	$ 28.91	$ 0.74	2.56%
		Dec-14	27.41	31.60	29.51	0.74	2.51%
		Jan-15	29.30	31.18	30.24	0.80	2.65%
		Feb-15	27.64	30.90	29.27	0.80	2.73%
		Mar-15	27.06	29.30	28.18	0.80	2.84%
		Apr-15	27.28	29.78	28.53	0.80	2.80%
							2.68%
TECO Energy, Inc.	TE	Nov-14	$ 19.12	$ 20.17	$ 19.65	$ 0.88	4.48%
		Dec-14	18.89	21.29	20.09	0.88	4.38%
		Jan-15	20.07	22.02	21.04	0.88	4.18%
		Feb-15	19.39	21.97	20.68	0.90	4.35%
		Mar-15	18.55	20.15	19.35	0.90	4.65%
		Apr-15	18.77	19.94	19.35	0.90	4.65%
							4.45%

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Dividend Yields
November 2014 - April 2015

Company	Ticker	Average Dividend Yield
ALLETE, Inc.	ALE	3.71%
Alliant Energy Corporation	LNT	3.34%
Ameren Corporation	AEE	3.76%
American Electric Power Company, Inc.	AEP	3.60%
Empire District Electric Company	EDE	3.82%
Great Plains Energy Inc.	GXP	3.58%
OGE Energy Corporation	OGE	2.94%
Otter Tail Corporation	OTTR	3.91%
PNM Resources, Inc.	PNM	2.68%
TECO Energy, Inc.	TE	4.45%
Westar Energy, Inc.	WR	3.56%
Xcel Energy Inc.	XEL	3.49%
Average		**3.57%**
Median		**3.59%**

			Price			Annualized	Dividend
			Low	High	Average	Dividend	Yield
Westar Energy, Inc.	WR	Nov-14	$ 37.24	$ 39.62	$ 38.43	$ 1.40	3.64%
		Dec-14	38.52	43.15	40.84	1.40	3.43%
		Jan-15	40.33	44.03	42.18	1.40	3.32%
		Feb-15	38.60	43.31	40.96	1.40	3.42%
		Mar-15	36.58	39.09	37.83	1.44	3.81%
		Apr-15	37.47	39.65	38.56	1.44	3.73%
							3.56%
Xcel Energy Inc.	XEL	Nov-14	$ 32.95	$ 34.10	$ 33.53	$ 1.20	3.58%
		Dec-14	33.49	37.58	35.54	1.20	3.38%
		Jan-15	35.60	38.35	36.97	1.20	3.25%
		Feb-15	34.60	37.84	36.22	1.20	3.31%
		Mar-15	33.41	35.39	34.40	1.28	3.72%
		Apr-15	33.51	35.35	34.43	1.28	3.72%
							3.49%

Source: SNL Financial

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Projected Earnings Retention Growth Rates

		Value Line Forecast 2018-2020				
Company	Ticker	EPS	DPS	ROE	Retention Rate	Retention Growth
ALLETE, Inc.	ALE	$4.00	$2.40	9.50%	40.00%	3.80%
Alliant Energy Corporation	LNT	$4.25	$2.85	12.00%	32.94%	3.95%
Ameren Corporation	AEE	$3.25	$1.85	9.50%	43.08%	4.09%
American Electric Power Company, Inc.	AEP	$4.50	$2.65	10.50%	41.11%	4.32%
Empire District Electric Company	EDE	$1.75	$1.20	8.50%	31.43%	2.67%
Great Plains Energy Inc.	GXP	$2.00	$1.20	7.50%	40.00%	3.00%
OGE Energy Corporation	OGE	$2.25	$1.55	11.00%	31.11%	3.42%
Otter Tail Corporation	OTTR	$2.35	$1.32	13.00%	43.83%	5.70%
PNM Resources, Inc.	PNM	$2.35	$1.15	9.50%	51.06%	4.85%
TECO Energy, Inc.	TE	$1.45	$1.05	12.00%	27.59%	3.31%
Westar Energy, Inc.	WR	$3.00	$1.65	9.50%	45.00%	4.28%
Xcel Energy Inc.	XEL	$2.50	$1.45	10.00%	42.00%	4.20%
Average						**3.97%**
Median						**4.02%**

Source: Value Line, as of January 31, 2015, February 20, 2015 and March 20, 2015.

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Blended Growth Rate Estimates

Company	Ticker	1/2 Zacks 5-Yr Earnings Growth Est.	1/2 Yahoo! Finance Earnings Growth	Average Earnings Growth	Retention Growth	Weighted Average
ALLETE, Inc.	ALE	N/A	6.00%	6.00%	3.80%	4.90%
Alliant Energy Corporation	LNT	5.30%	5.40%	5.35%	3.95%	4.65%
Ameren Corporation	AEE	7.30%	6.85%	7.08%	4.09%	5.58%
American Electric Power Company, Inc.	AEP	5.00%	5.18%	5.09%	4.32%	4.70%
Empire District Electric Company	EDE	3.00%	3.00%	3.00%	2.67%	2.84%
Great Plains Energy Inc.	GXP	5.40%	5.90%	5.65%	3.00%	4.33%
OGE Energy Corporation	OGE	5.00%	4.00%	4.50%	3.42%	3.96%
Otter Tail Corporation	OTTR	N/A	6.00%	6.00%	5.70%	5.85%
PNM Resources, Inc.	PNM	8.90%	9.86%	9.38%	4.85%	7.12%
TECO Energy, Inc.	TE	7.10%	9.20%	8.15%	3.31%	5.73%
Westar Energy, Inc.	WR	3.50%	3.07%	3.29%	4.28%	3.78%
Xcel Energy Inc.	XEL	4.70%	4.58%	4.64%	4.20%	4.42%
Average		**5.52%**	**5.75%**	**5.68%**	**3.97%**	**4.82%**
Median		**5.15%**	**5.65%**	**5.50%**	**4.02%**	**4.68%**

Source: Zacks.com and Yahoo Finance

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Retention Growth DCF Calculation

Company	Ticker	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
ALLETE, Inc.	ALE	3.71%	3.80%	3.80%	7.60%	1.0350	7.87%
Alliant Energy Corporation	LNT	3.34%	3.42%	3.95%	7.37%	1.0350	7.63%
Ameren Corporation	AEE	3.76%	3.86%	4.09%	7.95%	1.0350	8.23%
American Electric Power Company, Inc.	AEP	3.60%	3.69%	4.32%	8.01%	1.0350	8.29%
Empire District Electric Company	EDE	3.82%	3.88%	2.67%	6.55%	1.0350	6.78%
Great Plains Energy Inc.	GXP	3.58%	3.65%	3.00%	6.65%	1.0350	6.88%
OGE Energy Corporation	OGE	2.94%	3.01%	3.42%	6.43%	1.0350	6.65%
Otter Tail Corporation	OTTR	3.91%	4.04%	5.70%	9.74%	1.0350	10.08%
PNM Resources, Inc.	PNM	2.68%	2.76%	4.85%	7.61%	1.0350	7.88%
TECO Energy, Inc.	TE	4.45%	4.54%	3.31%	7.85%	1.0350	8.13%
Westar Energy, Inc.	WR	3.56%	3.65%	4.28%	7.93%	1.0350	8.21%
Xcel Energy Inc.	XEL	3.49%	3.58%	4.20%	7.78%	1.0350	8.06%
High					9.74%		10.08%
3rd Quartile					7.93%		8.21%
2nd Quartile (Median)					**7.70%**		**7.97%**
1st Quartile					7.19%		7.44%
Low					6.43%		6.65%

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Basic DCF Calculation

Company	Ticker	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
ALLETE, Inc.	ALE	3.71%	3.85%	6.00%	9.85%	1.0350	10.20%
Alliant Energy Corporation	LNT	3.34%	3.45%	5.35%	8.80%	1.0350	9.10%
Ameren Corporation	AEE	3.76%	3.93%	7.08%	11.00%	1.0350	11.39%
American Electric Power Company, Inc.	AEP	3.60%	3.71%	5.09%	8.80%	1.0350	9.11%
Empire District Electric Company	EDE	3.82%	3.89%	3.00%	6.89%	1.0350	7.13%
Great Plains Energy Inc.	GXP	3.58%	3.71%	5.65%	9.36%	1.0350	9.69%
OGE Energy Corporation	OGE	2.94%	3.03%	4.50%	7.53%	1.0350	7.79%
Otter Tail Corporation	OTTR	3.91%	4.05%	6.00%	10.05%	1.0350	10.40%
PNM Resources, Inc.	PNM	2.68%	2.84%	9.38%	12.22%	1.0350	12.65%
TECO Energy, Inc.	TE	4.45%	4.68%	8.15%	12.83%	1.0350	13.27%
Westar Energy, Inc.	WR	3.56%	3.63%	3.29%	6.92%	1.0350	7.16%
Xcel Energy Inc.	XEL	3.49%	3.59%	4.64%	8.23%	1.0350	8.52%
High					12.83%		13.27%
3rd Quartile					10.29%		10.65%
2nd Quartile (Median)					**9.08%**		**9.40%**
1st Quartile					8.06%		8.34%
Low					6.89%		7.13%

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Blended Growth Rate DCF Calculation

Company	Ticker	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
ALLETE, Inc.	ALE	3.71%	3.83%	4.90%	8.73%	1.0350	9.03%
Alliant Energy Corporation	LNT	3.34%	3.43%	4.65%	8.08%	1.0350	8.37%
Ameren Corporation	AEE	3.76%	3.89%	5.58%	9.47%	1.0350	9.81%
American Electric Power Company, Inc.	AEP	3.60%	3.70%	4.70%	8.40%	1.0350	8.70%
Empire District Electric Company	EDE	3.82%	3.89%	2.84%	6.72%	1.0350	6.96%
Great Plains Energy Inc.	GXP	3.58%	3.68%	4.33%	8.00%	1.0350	8.28%
OGE Energy Corporation	OGE	2.94%	3.02%	3.96%	6.98%	1.0350	7.22%
Otter Tail Corporation	OTTR	3.91%	4.05%	5.85%	9.90%	1.0350	10.24%
PNM Resources, Inc.	PNM	2.68%	2.80%	7.12%	9.92%	1.0350	10.26%
TECO Energy, Inc.	TE	4.45%	4.61%	5.73%	10.34%	1.0350	10.70%
Westar Energy, Inc.	WR	3.56%	3.64%	3.78%	7.42%	1.0350	7.68%
Xcel Energy Inc.	XEL	3.49%	3.59%	4.42%	8.01%	1.0350	8.29%
High					10.34%		10.70%
3rd Quartile					9.58%		9.92%
2nd Quartile (Median)					**8.24%**		**8.53%**
1st Quartile					7.86%		8.13%
Low					6.72%		6.96%

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
LyondellBasell Industries NV	LYB	473.301	103.520	48,996	0.3037%	2.70%	5.67%	0.0082%	0.0172%
American Express Co	AXP	1,015.796	77.450	78,673	0.4877%	1.34%	9.02%	0.0065%	0.0440%
Verizon Communications Inc	VZ	4,078.487	50.440	205,719	1.2752%	4.36%	7.60%	0.0556%	0.0969%
Avago Technologies Ltd	AVGO	256.587	116.880	29,990	0.1859%	1.30%	20.69%	0.0024%	0.0385%
Boeing Co/The	BA	691.517	143.340	99,122	0.6144%	2.54%	10.34%	0.0156%	0.0635%
Caterpillar Inc	CAT	603.700	86.880	52,449	0.3251%	3.22%	9.00%	0.0105%	0.0293%
JPMorgan Chase & Co	JPM	3,728.313	63.260	235,853	1.4620%	2.53%	7.36%	0.0370%	0.1076%
Chevron Corp	CVX	1,880.478	111.060	208,846	0.0000%	3.85%	-0.29%	0.0000%	0.0000%
Coca-Cola Co/The	KO	4,358.701	40.560	176,789	1.0959%	3.25%	6.34%	0.0357%	0.0695%
AbbVie Inc	ABBV	1,592.372	64.660	102,963	0.6382%	3.16%	8.03%	0.0201%	0.0513%
Walt Disney Co/The	DIS	1,699.563	108.720	184,776	1.1454%	1.06%	11.59%	0.0121%	0.1327%
EI du Pont de Nemours & Co	DD	905.237	73.200	66,263	0.4108%	2.68%	5.82%	0.0110%	0.0239%
Exxon Mobil Corp	XOM	4,189.490	87.370	366,036	2.2690%	3.34%	10.68%	0.0758%	0.2423%
Phillips 66	PSX	542.327	79.310	43,012	0.2666%	2.52%	5.23%	0.0067%	0.0140%
General Electric Co	GE	10,067.496	27.080	272,628	1.6900%	3.40%	8.44%	0.0574%	0.1426%
Hewlett-Packard Co	HPQ	1,817.559	32.970	59,925	0.3715%	2.14%	3.43%	0.0079%	0.0127%
Home Depot Inc/The	HD	1,298.359	106.980	138,898	0.8610%	2.21%	14.24%	0.0190%	0.1226%
International Business Machines Corp	IBM	984.734	171.290	168,675	1.0456%	3.04%	6.88%	0.0317%	0.0719%
Johnson & Johnson	JNJ	2,780.560	99.200	275,832	1.7098%	3.02%	6.58%	0.0517%	0.1125%
McDonald's Corp	MCD	959.127	96.550	92,604	0.5740%	3.52%	7.98%	0.0202%	0.0458%
Merck & Co Inc	MRK	2,828.453	59.560	168,463	1.0443%	3.02%	6.22%	0.0316%	0.0649%
3M Co	MMM	634.341	156.390	99,205	0.6149%	2.62%	9.18%	0.0161%	0.0564%
Bank of America Corp	BAC	10,502.101	15.930	167,298	1.0370%	1.26%	8.83%	0.0130%	0.0916%
Pfizer Inc	PFE	6,140.333	33.930	208,341	1.2915%	3.30%	3.97%	0.0426%	0.0513%
Procter & Gamble Co/The	PG	2,712.996	79.510	215,710	1.3371%	3.33%	7.69%	0.0446%	0.1028%
AT&T Inc	T	5,190.168	34.640	179,787	1.1145%	5.43%	4.56%	0.0605%	0.0509%
Travelers Cos Inc/The	TRV	318.698	101.110	32,224	0.1997%	2.41%	6.74%	0.0048%	0.0135%
United Technologies Corp	UTX	890.202	113.750	101,260	0.6277%	2.25%	8.66%	0.0141%	0.0544%
Analog Devices Inc	ADI	311.627	61.840	19,271	0.1195%	2.59%	10.82%	0.0031%	0.0129%
Wal-Mart Stores Inc	WMT	3,225.503	78.050	251,751	1.5605%	2.51%	6.31%	0.0392%	0.0984%
Cisco Systems Inc	CSCO	5,104.739	28.830	147,170	0.9123%	2.91%	7.18%	0.0266%	0.0655%
Intel Corp	INTC	4,744.000	32.550	154,417	0.9572%	2.95%	7.85%	0.0282%	0.0751%
General Motors Co	GM	1,607.208	35.060	56,349	0.3493%	4.11%	12.31%	0.0143%	0.0430%
Microsoft Corp	MSFT	8,089.575	48.640	393,477	2.4391%	2.55%	7.62%	0.0622%	0.1859%
Dollar General Corp	DG	303.704	72.710	22,082	0.1369%	1.21%	12.41%	0.0017%	0.0170%
Kinder Morgan Inc/DE	KMI	2,168.155	42.950	93,122	0.5772%	4.47%	10.00%	0.0258%	0.0577%
Citigroup Inc	C	3,034.000	53.320	161,773	1.0028%	0.38%	13.38%	0.0038%	0.1341%
Nielsen NV	NLSN	369.889	44.940	16,623	0.1030%	2.49%	14.00%	0.0026%	0.0144%
American International Group Inc	AIG	1,353.970	56.290	76,215	0.4724%	0.89%	9.04%	0.0042%	0.0427%
Honeywell International Inc	HON	781.707	100.920	78,890	0.4890%	2.05%	9.39%	0.0100%	0.0459%
Altria Group Inc	MO	1,966.558	50.050	98,426	0.6101%	4.16%	7.51%	0.0254%	0.0458%
HCA Holdings Inc	HCA	419.504	74.010	31,047	0.0000%	N/A	10.95%	n/a	0.0000%
Under Armour Inc	UA	179.314	77.550	13,906	0.0000%	N/A	23.34%	n/a	0.0000%
International Paper Co	IP	422.866	53.720	22,716	0.1408%	2.98%	8.75%	0.0042%	0.0123%
Abbott Laboratories	ABT	1,508.978	46.420	70,047	0.4342%	2.07%	11.49%	0.0090%	0.0499%
Aflac Inc	AFL	438.406	63.040	27,637	0.1713%	2.47%	9.68%	0.0042%	0.0166%
Air Products & Chemicals Inc	APD	214.765	143.430	30,804	0.1909%	2.26%	10.90%	0.0043%	0.0208%
Airgas Inc	ARG	75.119	101.280	7,608	0.0472%	2.37%	9.82%	0.0011%	0.0046%
Royal Caribbean Cruises Ltd	RCL	219.910	68.060	14,967	0.0928%	1.76%	20.22%	0.0016%	0.0188%
American Electric Power Co Inc	AEP	489.942	56.870	27,863	0.1727%	3.73%	5.45%	0.0064%	0.0094%
Hess Corp	HES	287.426	76.900	22,103	0.0000%	1.30%	-0.36%	0.0000%	0.0000%
Anadarko Petroleum Corp	APC	515.477	94.100	48,506	0.3007%	1.15%	1.66%	0.0035%	0.0050%
Aon PLC	AON	281.842	96.230	27,122	0.1681%	1.25%	12.14%	0.0021%	0.0204%
Apache Corp	APA	376.856	68.400	25,777	0.1598%	1.46%	4.03%	0.0023%	0.0064%

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
Archer-Daniels-Midland Co	ADM	628.936	48.880	30,742	0.1906%	2.29%	4.86%	0.0044%	0.0093%
AGL Resources Inc	GAS	119.935	50.270	6,029	0.0374%	4.06%	5.83%	0.0015%	0.0022%
Automatic Data Processing Inc	ADP	475.152	84.540	40,169	0.2490%	2.32%	10.29%	0.0058%	0.0256%
AutoZone Inc	AZO	31.723	672.660	21,339	0.0000%	N/A	12.60%	n/a	0.0000%
Avery Dennison Corp	AVY	90.466	55.590	5,029	0.0312%	2.66%	7.45%	0.0008%	0.0023%
Baker Hughes Inc	BHI	434.676	68.460	29,758	0.1845%	0.99%	5.83%	0.0018%	0.0108%
Ball Corp	BLL	137.506	73.410	10,094	0.0626%	0.71%	10.60%	0.0004%	0.0066%
Bank of New York Mellon Corp/The	BK	1,114.639	42.340	47,194	0.2925%	1.61%	11.60%	0.0047%	0.0339%
CR Bard Inc	BCR	74.246	166.580	12,368	0.0767%	0.53%	9.60%	0.0004%	0.0074%
Baxter International Inc	BAX	543.531	68.740	37,362	0.2316%	3.03%	8.47%	0.0070%	0.0196%
Becton Dickinson and Co	BDX	208.891	140.870	29,426	0.1824%	1.70%	11.40%	0.0031%	0.0208%
Berkshire Hathaway Inc	BRK/B	1,227.069	141.210	173,274	0.0000%	N/A	5.85%	n/a	0.0000%
Best Buy Co Inc	BBY	352.334	34.650	12,208	0.0757%	2.66%	11.43%	0.0020%	0.0087%
H&R Block Inc	HRB	275.248	30.240	8,323	0.0516%	2.65%	11.00%	0.0014%	0.0057%
Boston Scientific Corp	BSX	1,339.181	17.820	23,864	0.0000%	N/A	7.39%	n/a	0.0000%
Bristol-Myers Squibb Co	BMY	1,666.974	63.730	106,236	0.6585%	2.32%	16.42%	0.0153%	0.1081%
Brown-Forman Corp	BF/B	126.089	90.230	11,377	0.0705%	1.40%	6.81%	0.0010%	0.0048%
Cabot Oil & Gas Corp	COG	413.604	33.820	13,988	0.0867%	0.24%	28.68%	0.0002%	0.0249%
Campbell Soup Co	CPB	311.790	44.710	13,940	0.0864%	2.79%	3.70%	0.0024%	0.0032%
Kansas City Southern	KSU	110.545	102.490	11,330	0.0702%	1.29%	11.48%	0.0009%	0.0081%
Carnival Corp	CCL	593.428	43.970	26,093	0.1617%	2.27%	17.10%	0.0037%	0.0277%
CenturyLink Inc	CTL	565.443	35.960	20,333	0.1260%	6.01%	0.89%	0.0076%	0.0011%
Chubb Corp/The	CB	230.523	98.350	22,672	0.1405%	2.32%	9.20%	0.0033%	0.0129%
Cigna Corp	CI	257.367	124.640	32,078	0.1988%	0.03%	11.23%	0.0001%	0.0223%
Frontier Communications Corp	FTR	1,000.897	6.860	6,866	0.0426%	6.12%	37.10%	0.0026%	0.0158%
Clorox Co/The	CLX	131.178	106.100	13,918	0.0863%	2.79%	6.68%	0.0024%	0.0058%
CMS Energy Corp	CMS	276.797	33.930	9,392	0.0582%	3.42%	6.15%	0.0020%	0.0036%
Coca-Cola Enterprises Inc	CCE	232.985	44.410	10,347	0.0641%	2.52%	6.15%	0.0016%	0.0039%
Colgate-Palmolive Co	CL	904.570	67.280	60,859	0.3773%	2.26%	9.36%	0.0085%	0.0353%
Comerica Inc	CMA	178.009	47.410	8,439	0.0523%	1.77%	10.40%	0.0009%	0.0054%
CA Inc	CA	442.805	31.770	14,068	0.0000%	3.15%	-2.20%	0.0000%	0.0000%
Computer Sciences Corp	CSC	141.047	64.450	9,090	0.0563%	1.43%	9.10%	0.0008%	0.0051%
ConAgra Foods Inc	CAG	427.052	36.150	15,438	0.0957%	2.77%	7.50%	0.0026%	0.0072%
Consolidated Edison Inc	ED	292.887	61.550	18,027	0.1117%	4.22%	2.78%	0.0047%	0.0031%
SL Green Realty Corp	SLG	99.533	122.360	12,179	0.0755%	1.96%	5.84%	0.0015%	0.0044%
Corning Inc	GLW	1,268.799	20.930	26,556	0.1646%	2.29%	5.09%	0.0038%	0.0084%
CSX Corp	CSX	987.981	36.090	35,656	0.2210%	2.00%	10.95%	0.0044%	0.0242%
Cummins Inc	CMI	181.312	138.260	25,068	0.1554%	2.26%	10.47%	0.0035%	0.0163%
Danaher Corp	DHR	707.526	81.880	57,932	0.3591%	0.66%	11.25%	0.0024%	0.0404%
Target Corp	TGT	639.122	78.830	50,382	0.3123%	2.64%	9.35%	0.0082%	0.0292%
Deere & Co	DE	339.496	90.520	30,731	0.1905%	2.65%	5.86%	0.0051%	0.0112%
Dominion Resources Inc/VA	D	588.376	71.680	42,175	0.2614%	3.61%	6.60%	0.0094%	0.0173%
Dover Corp	DOV	160.383	75.720	12,144	0.0753%	2.11%	12.00%	0.0016%	0.0090%
Dow Chemical Co/The	DOW	1,152.023	51.000	58,753	0.3642%	3.29%	7.60%	0.0120%	0.0277%
Duke Energy Corp	DUK	708.016	77.570	54,921	0.3404%	4.10%	5.99%	0.0140%	0.0204%
Eaton Corp PLC	ETN	467.100	68.730	32,104	0.1990%	3.20%	8.28%	0.0064%	0.0165%
Ecolab Inc	ECL	297.350	111.980	33,297	0.2064%	1.18%	13.17%	0.0024%	0.0272%
PerkinElmer Inc	PKI	113.110	51.260	5,798	0.0359%	0.55%	9.36%	0.0002%	0.0034%
EMC Corp/MA	EMC	1,988.087	26.910	53,499	0.3316%	1.71%	10.44%	0.0057%	0.0346%
Emerson Electric Co	EMR	685.202	58.830	40,310	0.2499%	3.20%	6.55%	0.0080%	0.0164%
EOG Resources Inc	EOG	548.466	98.950	54,271	0.3364%	0.68%	2.56%	0.0023%	0.0086%
Entergy Corp	ETR	180.515	77.180	13,932	0.0864%	4.30%	0.62%	0.0037%	0.0005%
Equifax Inc	EFX	119.006	96.930	11,535	0.0715%	1.20%	13.75%	0.0009%	0.0098%
EQT Corp	EQT	152.346	89.940	13,702	0.0000%	0.13%	N/A	0.0000%	n/a

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
XL Group PLC	XL	256.601	37.080	9,515	0.0590%	1.73%	5.87%	0.0010%	0.0035%
Family Dollar Stores Inc	FDO	114.509	78.140	8,948	0.0555%	1.59%	3.85%	0.0009%	0.0021%
FedEx Corp	FDX	283.757	169.570	48,117	0.2983%	0.47%	14.76%	0.0014%	0.0440%
Macy's Inc	M	341.600	64.630	22,078	0.1369%	1.93%	6.95%	0.0026%	0.0095%
FMC Corp	FMC	133.527	59.310	7,919	0.0491%	1.11%	10.00%	0.0005%	0.0049%
Ford Motor Co	F	3,904.504	15.800	61,691	0.3824%	3.80%	15.65%	0.0145%	0.0598%
NextEra Energy Inc	NEE	444.124	100.930	44,825	0.2779%	3.05%	5.93%	0.0085%	0.0165%
Franklin Resources Inc	BEN	618.559	51.560	31,893	0.1977%	1.16%	9.63%	0.0023%	0.0190%
Freeport-McMoRan Inc	FCX	1,040.045	23.270	24,202	0.1500%	0.86%	21.74%	0.0013%	0.0326%
Gannett Co Inc	GCI	227.807	34.320	7,818	0.0485%	2.33%	4.35%	0.0011%	0.0021%
Gap Inc/The	GPS	419.735	39.640	16,638	0.1031%	2.32%	9.60%	0.0024%	0.0099%
General Dynamics Corp	GD	328.733	137.320	45,142	0.2798%	2.01%	8.74%	0.0056%	0.0245%
General Mills Inc	GIS	596.090	55.340	32,988	0.2045%	3.18%	6.98%	0.0065%	0.0143%
Genuine Parts Co	GPC	152.699	89.850	13,720	0.0850%	2.74%	6.92%	0.0023%	0.0059%
WW Grainger Inc	GWW	66.921	248.430	16,625	0.1031%	1.88%	11.85%	0.0019%	0.0122%
Halliburton Co	HAL	850.874	48.950	41,650	0.2582%	1.47%	14.62%	0.0038%	0.0377%
Harley-Davidson Inc	HOG	210.997	56.210	11,860	0.0735%	2.21%	11.13%	0.0016%	0.0082%
Harman International Industries Inc	HAR	71.152	130.380	9,277	0.0575%	1.01%	16.70%	0.0006%	0.0096%
Joy Global Inc	JOY	97.375	42.640	4,152	0.0257%	1.88%	16.05%	0.0005%	0.0041%
Harris Corp	HRS	104.119	80.240	8,355	0.0000%	2.34%	N/A	0.0000%	n/a
HCP Inc	HCP	461.489	40.290	18,593	0.1153%	5.61%	3.91%	0.0065%	0.0045%
Helmerich & Payne Inc	HP	107.641	77.970	8,393	0.0520%	3.53%	18.57%	0.0018%	0.0097%
Hershey Co/The	HSY	158.712	91.920	14,589	0.0904%	2.33%	9.42%	0.0021%	0.0085%
Hormel Foods Corp	HRL	264.067	54.350	14,352	0.0890%	1.84%	5.85%	0.0016%	0.0052%
Starwood Hotels & Resorts Worldwide Inc	HOT	170.886	85.950	14,688	0.0910%	1.75%	9.16%	0.0016%	0.0083%
Mondelez International Inc	MDLZ	1,626.623	38.370	62,414	0.3869%	1.56%	9.57%	0.0060%	0.0370%
CenterPoint Energy Inc	CNP	429.947	20.970	9,016	0.0559%	4.72%	5.20%	0.0026%	0.0029%
Humana Inc	HUM	149.781	165.600	24,804	0.1538%	0.70%	11.68%	0.0011%	0.0180%
Illinois Tool Works Inc	ITW	373.323	93.580	34,936	0.2166%	2.07%	8.95%	0.0045%	0.0194%
Ingersoll-Rand PLC	IR	264.719	65.840	17,429	0.1080%	1.76%	10.30%	0.0019%	0.0111%
Interpublic Group of Cos Inc/The	IPG	412.937	20.840	8,606	0.0533%	2.30%	7.53%	0.0012%	0.0040%
International Flavors & Fragrances Inc	IFF	80.746	114.750	9,266	0.0574%	1.64%	9.87%	0.0009%	0.0057%
Jacobs Engineering Group Inc	JEC	128.305	42.860	5,499	0.0000%	N/A	7.50%	n/a	0.0000%
Johnson Controls Inc	JCI	654.831	50.380	32,990	0.2045%	2.06%	10.50%	0.0042%	0.0215%
Hanesbrands Inc	HBI	400.806	31.080	12,457	0.0772%	1.29%	11.33%	0.0010%	0.0088%
Kellogg Co	K	356.189	63.330	22,557	0.1398%	3.09%	4.12%	0.0043%	0.0058%
Perrigo Co PLC	PRGO	146.263	183.280	26,807	0.1662%	0.27%	13.50%	0.0005%	0.0224%
Kimberly-Clark Corp	KMB	364.099	109.690	39,938	0.2476%	3.21%	7.50%	0.0079%	0.0186%
Kimco Realty Corp	KIM	412.622	24.100	9,944	0.0616%	3.98%	4.44%	0.0025%	0.0027%
Kohl's Corp	KSS	202.802	71.650	14,531	0.0901%	2.51%	8.26%	0.0023%	0.0074%
Oracle Corp	ORCL	4,367.070	43.620	190,492	1.1808%	1.38%	8.11%	0.0162%	0.0957%
Kroger Co/The	KR	491.107	68.910	33,842	0.2098%	1.07%	11.01%	0.0023%	0.0231%
Legg Mason Inc	LM	112.656	52.650	5,931	0.0368%	1.22%	17.61%	0.0004%	0.0065%
Leggett & Platt Inc	LEG	138.016	42.470	5,862	0.0000%	2.92%	N/A	0.0000%	n/a
Lennar Corp	LEN	173.901	45.800	7,965	0.0494%	0.35%	8.00%	0.0002%	0.0039%
Leucadia National Corp	LUK	366.724	23.770	8,717	0.0000%	1.05%	N/A	0.0000%	n/a
Eli Lilly & Co	LLY	1,109.741	71.870	79,757	0.4944%	2.78%	8.48%	0.0138%	0.0419%
L Brands Inc	LB	292.430	89.360	26,132	0.1620%	2.24%	12.55%	0.0036%	0.0203%
Lincoln National Corp	LNC	253.022	56.490	14,293	0.0886%	1.42%	10.30%	0.0013%	0.0091%
Loews Corp	L	372.184	41.640	15,498	0.0000%	0.60%	N/A	0.0000%	n/a
Lowe's Cos Inc	LOW	951.705	68.860	65,534	0.4062%	1.34%	16.84%	0.0054%	0.0684%
Host Hotels & Resorts Inc	HST	756.990	20.140	15,246	0.0945%	3.97%	10.45%	0.0038%	0.0099%
Marsh & McLennan Cos Inc	MMC	538.408	56.160	30,237	0.1874%	1.99%	12.48%	0.0037%	0.0234%
Masco Corp	MAS	348.596	26.490	9,234	0.0572%	1.36%	12.68%	0.0008%	0.0073%

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
Mattel Inc	MAT	338.339	28.160	9,528	0.0591%	5.40%	9.50%	0.0032%	0.0056%
McGraw Hill Financial Inc	MHFI	273.700	104.300	28,547	0.1770%	1.27%	12.50%	0.0022%	0.0221%
Medtronic PLC	MDT	1,425.067	74.450	106,096	0.6577%	1.64%	6.70%	0.0108%	0.0441%
CVS Health Corp	CVS	1,135.266	99.290	112,721	0.6987%	1.41%	14.38%	0.0099%	0.1004%
Micron Technology Inc	MU	1,081.540	28.130	30,424	0.0000%	N/A	11.22%	n/a	0.0000%
Motorola Solutions Inc	MSI	211.273	59.750	12,624	0.0783%	2.28%	9.83%	0.0018%	0.0077%
Murphy Oil Corp	MUR	177.967	47.610	8,473	0.0525%	2.94%	13.00%	0.0015%	0.0068%
Mylan NV	MYL	489.406	72.260	35,364	0.0000%	N/A	11.48%	n/a	0.0000%
Laboratory Corp of America Holdings	LH	100.436	119.560	12,008	0.0000%	N/A	11.42%	n/a	0.0000%
Tenet Healthcare Corp	THC	99.154	47.860	4,746	0.0000%	N/A	13.99%	n/a	0.0000%
Newell Rubbermaid Inc	NWL	268.978	38.130	10,256	0.0636%	1.99%	9.38%	0.0013%	0.0060%
Newmont Mining Corp	NEM	499.847	26.490	13,241	0.0821%	0.38%	1.93%	0.0003%	0.0016%
Twenty-First Century Fox Inc	FOXA	1,327.615	34.080	45,245	0.2805%	0.88%	14.74%	0.0025%	0.0413%
NIKE Inc	NKE	682.190	98.840	67,428	0.4180%	1.13%	11.71%	0.0047%	0.0490%
NiSource Inc	NI	317.378	43.420	13,781	0.0854%	2.40%	6.00%	0.0020%	0.0051%
Noble Energy Inc	NBL	387.846	50.720	19,672	0.1219%	1.42%	0.12%	0.0017%	0.0001%
Norfolk Southern Corp	NSC	304.849	100.850	30,744	0.1906%	2.34%	9.98%	0.0045%	0.0190%
Eversource Energy	ES	317.405	48.760	15,477	0.0959%	3.42%	6.70%	0.0033%	0.0064%
Northrop Grumman Corp	NOC	193.785	154.040	29,851	0.1850%	1.82%	6.57%	0.0034%	0.0122%
Wells Fargo & Co	WFC	5,162.900	55.100	284,476	1.7634%	2.72%	10.44%	0.0480%	0.1841%
Nucor Corp	NUE	319.049	48.860	15,589	0.0966%	3.05%	11.10%	0.0029%	0.0107%
PVH Corp	PVH	82.527	103.350	8,529	0.0529%	0.15%	4.36%	0.0001%	0.0023%
Occidental Petroleum Corp	OXY	770.566	80.100	61,722	0.3826%	3.60%	8.00%	0.0138%	0.0306%
Omnicom Group Inc	OMC	244.312	75.760	18,509	0.1147%	2.64%	6.57%	0.0030%	0.0075%
ONEOK Inc	OKE	208.753	48.100	10,041	0.0622%	5.03%	10.85%	0.0031%	0.0068%
Owens-Illinois Inc	OI	161.251	23.910	3,856	0.0000%	N/A	4.35%	n/a	0.0000%
PG&E Corp	PCG	479.974	52.920	25,400	0.1575%	3.44%	5.93%	0.0054%	0.0093%
Parker-Hannifin Corp	PH	142.455	119.360	17,003	0.1054%	2.11%	8.92%	0.0022%	0.0094%
PPL Corp	PPL	667.287	34.030	22,708	0.1408%	4.38%	1.58%	0.0062%	0.0022%
PepsiCo Inc	PEP	1,476.051	95.120	140,402	0.8703%	2.75%	6.36%	0.0240%	0.0554%
Exelon Corp	EXC	861.244	34.020	29,300	0.1816%	3.64%	6.78%	0.0066%	0.0123%
ConocoPhillips	COP	1,231.462	67.920	83,641	0.5185%	4.30%	7.25%	0.0223%	0.0376%
PulteGroup Inc	PHM	364.606	19.300	7,037	0.0436%	1.66%	8.50%	0.0007%	0.0037%
Pinnacle West Capital Corp	PNW	110.746	61.200	6,778	0.0420%	3.89%	5.06%	0.0016%	0.0021%
Pitney Bowes Inc	PBI	201.666	22.370	4,511	0.0280%	3.35%	14.00%	0.0009%	0.0039%
Plum Creek Timber Co Inc	PCL	176.061	42.200	7,430	0.0461%	4.17%	5.27%	0.0019%	0.0024%
PNC Financial Services Group Inc/The	PNC	520.690	91.730	47,763	0.2961%	2.22%	7.01%	0.0066%	0.0208%
PPG Industries Inc	PPG	135.926	221.560	30,116	0.1867%	1.30%	7.28%	0.0024%	0.0136%
Praxair Inc	PX	288.310	121.930	35,154	0.2179%	2.35%	9.28%	0.0051%	0.0202%
Precision Castparts Corp	PCP	141.768	206.690	29,302	0.1816%	0.06%	10.78%	0.0001%	0.0196%
Progressive Corp/The	PGR	587.565	26.660	15,664	0.0971%	2.57%	9.18%	0.0025%	0.0089%
Public Service Enterprise Group Inc	PEG	506.362	41.540	21,034	0.1304%	3.76%	4.81%	0.0049%	0.0063%
Raytheon Co	RTN	305.142	104.000	31,735	0.1967%	2.58%	6.64%	0.0051%	0.0131%
Robert Half International Inc	RHI	135.263	55.450	7,500	0.0465%	1.44%	15.68%	0.0007%	0.0073%
Ryder System Inc	R	53.309	95.360	5,084	0.0315%	1.55%	13.08%	0.0005%	0.0041%
SCANA Corp	SCG	142.917	52.980	7,572	0.0469%	4.11%	5.50%	0.0019%	0.0026%
Edison International	EIX	325.811	60.940	19,855	0.1231%	2.74%	4.50%	0.0034%	0.0055%
Schlumberger Ltd	SLB	1,269.727	94.610	120,129	0.7447%	2.11%	14.77%	0.0157%	0.1100%
Charles Schwab Corp/The	SCHW	1,313.002	30.500	40,047	0.2482%	0.79%	22.52%	0.0020%	0.0559%
Sherwin-Williams Co/The	SHW	93.186	278.000	25,906	0.1606%	0.96%	14.50%	0.0015%	0.0233%
JM Smucker Co/The	SJM	119.663	115.920	13,871	0.0860%	2.21%	6.08%	0.0019%	0.0052%
Snap-on Inc	SNA	58.094	149.550	8,688	0.0539%	1.42%	6.95%	0.0008%	0.0037%
AMETEK Inc	AME	241.430	52.420	12,656	0.0785%	0.69%	11.05%	0.0005%	0.0087%
Southern Co/The	SO	908.997	44.300	40,269	0.2496%	4.90%	3.85%	0.0122%	0.0096%

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
BB&T Corp	BBT	723.159	38.290	27,690	0.1716%	2.82%	10.84%	0.0048%	0.0186%
Southwest Airlines Co	LUV	668.297	40.560	27,106	0.1680%	0.59%	14.91%	0.0010%	0.0251%
Southwestern Energy Co	SWN	384.555	28.030	10,779	0.0000%	N/A	4.69%	n/a	0.0000%
Stanley Black & Decker Inc	SWK	153.726	98.700	15,173	0.0941%	2.11%	9.80%	0.0020%	0.0092%
Public Storage	PSA	172.761	187.910	32,464	0.2012%	3.62%	5.19%	0.0073%	0.0104%
SunTrust Banks Inc	STI	524.798	41.500	21,779	0.1350%	2.31%	6.10%	0.0031%	0.0082%
Sysco Corp	SYY	592.343	37.030	21,934	0.1360%	3.24%	8.50%	0.0044%	0.0116%
TECO Energy Inc	TE	235.541	18.950	4,464	0.0277%	4.75%	8.45%	0.0013%	0.0023%
Tesoro Corp	TSO	125.746	85.830	10,793	0.0669%	1.98%	17.96%	0.0013%	0.0120%
Texas Instruments Inc	TXN	1,047.142	54.210	56,766	0.3519%	2.51%	9.40%	0.0088%	0.0331%
Textron Inc	TXT	277.644	43.980	12,211	0.0757%	0.18%	9.26%	0.0001%	0.0070%
Thermo Fisher Scientific Inc	TMO	398.057	125.680	50,028	0.3101%	0.48%	12.30%	0.0015%	0.0381%
Tiffany & Co	TIF	129.279	87.480	11,309	0.0701%	1.74%	11.93%	0.0012%	0.0084%
TJX Cos Inc/The	TJX	682.260	64.540	44,033	0.2730%	1.30%	11.91%	0.0036%	0.0325%
Torchmark Corp	TMK	127.107	56.110	7,132	0.0442%	0.96%	5.12%	0.0004%	0.0023%
Total System Services Inc	TSS	185.054	39.560	7,321	0.0454%	1.01%	11.00%	0.0005%	0.0050%
Tyco International Plc	TYC	421.032	39.380	16,580	0.1028%	2.08%	10.93%	0.0021%	0.0112%
Union Pacific Corp	UNP	875.591	106.230	93,014	0.5766%	2.07%	13.23%	0.0119%	0.0763%
UnitedHealth Group Inc	UNH	951.625	111.400	106,011	0.6571%	1.35%	11.58%	0.0088%	0.0761%
Unum Group	UNM	249.511	34.160	8,523	0.0528%	1.93%	9.00%	0.0010%	0.0048%
Marathon Oil Corp	MRO	675.177	31.100	20,998	0.1302%	2.70%	6.77%	0.0035%	0.0088%
Varian Medical Systems Inc	VAR	100.072	88.850	8,891	0.0000%	N/A	10.50%	n/a	0.0000%
Ventas Inc	VTR	330.882	68.900	22,798	0.1413%	3.36%	3.68%	0.0048%	0.0052%
VF Corp	VFC	425.488	72.430	30,818	0.1910%	1.77%	12.80%	0.0034%	0.0245%
Vornado Realty Trust	VNO	188.161	103.490	19,473	0.1207%	2.44%	8.58%	0.0029%	0.0104%
ADT Corp/The	ADT	171.297	37.600	6,441	0.0399%	2.23%	6.03%	0.0009%	0.0024%
Vulcan Materials Co	VMC	132.615	85.520	11,341	0.0703%	0.47%	5.50%	0.0003%	0.0039%
Weyerhaeuser Co	WY	518.727	31.510	16,345	0.1013%	3.68%	4.63%	0.0037%	0.0047%
Whirlpool Corp	WHR	78.644	175.600	13,810	0.0856%	2.05%	19.69%	0.0018%	0.0169%
Williams Cos Inc/The	WMB	748.961	51.190	38,339	0.2377%	4.53%	10.50%	0.0108%	0.0250%
Integrys Energy Group Inc	TEG	79.963	73.100	5,845	0.0362%	3.72%	3.20%	0.0013%	0.0012%
Wisconsin Energy Corp	WEC	225.497	49.120	11,076	0.0687%	3.44%	5.50%	0.0024%	0.0038%
Xerox Corp	XRX	1,103.946	11.500	12,695	0.0787%	2.43%	9.15%	0.0019%	0.0072%
Adobe Systems Inc	ADBE	500.269	76.060	38,050	0.0000%	N/A	15.03%	n/a	0.0000%
AES Corp/VA	AES	703.204	13.250	9,317	0.0578%	3.02%	5.92%	0.0017%	0.0034%
Amgen Inc	AMGN	760.324	157.910	120,063	0.7442%	2.00%	10.26%	0.0149%	0.0764%
Apple Inc	AAPL	5,761.030	125.150	720,993	4.4693%	1.66%	15.63%	0.0743%	0.6987%
Autodesk Inc	ADSK	227.621	56.830	12,936	0.0000%	N/A	17.42%	n/a	0.0000%
Cintas Corp	CTAS	114.395	79.950	9,146	0.0567%	1.06%	11.48%	0.0006%	0.0065%
Comcast Corp	CMCSA	2,121.049	57.760	122,512	0.7594%	1.73%	12.68%	0.0131%	0.0963%
Molson Coors Brewing Co	TAP	163.225	73.510	11,999	0.0744%	2.23%	2.91%	0.0017%	0.0022%
KLA-Tencor Corp	KLAC	159.921	58.800	9,403	0.0583%	3.40%	3.47%	0.0020%	0.0020%
Marriott International Inc/MD	MAR	274.950	80.050	22,010	0.1364%	1.00%	15.49%	0.0014%	0.0211%
McCormick & Co Inc/MD	MKC	115.816	75.300	8,721	0.0541%	2.12%	5.80%	0.0011%	0.0031%
Nordstrom Inc	JWN	190.406	75.560	14,387	0.0892%	1.96%	9.83%	0.0017%	0.0088%
PACCAR Inc	PCAR	354.666	65.350	23,177	0.1437%	1.35%	8.80%	0.0019%	0.0126%
Costco Wholesale Corp	COST	439.974	143.050	62,938	0.3901%	1.12%	10.28%	0.0044%	0.0401%
Sigma-Aldrich Corp	SIAL	119.460	138.920	16,595	0.1029%	0.66%	8.48%	0.0007%	0.0087%
St Jude Medical Inc	STJ	280.122	70.050	19,623	0.1216%	1.66%	10.45%	0.0020%	0.0127%
Stryker Corp	SYK	378.409	92.240	34,904	0.2164%	1.50%	10.78%	0.0032%	0.0233%
Tyson Foods Inc	TSN	304.573	39.500	12,031	0.0746%	1.01%	9.15%	0.0008%	0.0068%
Altera Corp	ALTR	301.089	41.680	12,549	0.0778%	1.73%	11.50%	0.0013%	0.0089%
Applied Materials Inc	AMAT	1,228.697	19.790	24,316	0.1507%	2.02%	12.68%	0.0030%	0.0191%
Time Warner Inc	TWX	824.602	84.410	69,605	0.4315%	1.66%	11.03%	0.0072%	0.0476%

Montana-Dakota Utilities Co.

Market DCF Calculation

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S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
Bed Bath & Beyond Inc	BBBY	173.182	70.460	12,202	0.0000%	N/A	7.88%	n/a	0.0000%
American Airlines Group Inc	AAL	692.799	48.285	33,452	0.2074%	0.83%	23.54%	0.0017%	0.0488%
Cardinal Health Inc	CAH	330.131	84.340	27,843	0.1726%	1.62%	11.55%	0.0028%	0.0199%
Celgene Corp	CELG	793.144	108.060	85,707	0.0000%	N/A	26.61%	n/a	0.0000%
Cerner Corp	CERN	343.932	71.810	24,698	0.0000%	N/A	18.47%	n/a	0.0000%
Cincinnati Financial Corp	CINF	164.358	50.640	8,323	0.0000%	3.63%	N/A	0.0000%	n/a
Cablevision Systems Corp	CVC	221.568	19.980	4,427	0.0274%	3.00%	1.02%	0.0008%	0.0003%
DR Horton Inc	DHI	366.625	25.400	9,312	0.0577%	0.98%	11.20%	0.0006%	0.0065%
Flowserve Corp	FLS	134.451	58.530	7,869	0.0488%	1.23%	8.76%	0.0006%	0.0043%
Electronic Arts Inc	EA	310.036	58.090	18,010	0.0000%	N/A	15.67%	n/a	0.0000%
Express Scripts Holding Co	ESRX	729.291	86.400	63,011	0.0000%	N/A	12.91%	n/a	0.0000%
Expeditors International of Washington Inc	EXPD	191.091	45.830	8,758	0.0543%	1.40%	11.32%	0.0008%	0.0061%
Fastenal Co	FAST	293.955	42.620	12,528	0.0777%	2.63%	15.75%	0.0020%	0.0122%
M&T Bank Corp	MTB	132.856	119.670	15,899	0.0986%	2.34%	6.83%	0.0023%	0.0067%
Fiserv Inc	FISV	238.053	77.600	18,473	0.0000%	N/A	12.96%	n/a	0.0000%
Fifth Third Bancorp	FITB	815.207	20.000	16,304	0.1011%	2.60%	9.60%	0.0026%	0.0097%
Gilead Sciences Inc	GILD	1,483.063	100.510	149,063	0.9240%	1.71%	13.05%	0.0158%	0.1206%
Hasbro Inc	HAS	124.616	70.790	8,822	0.0547%	2.60%	10.40%	0.0014%	0.0057%
Huntington Bancshares Inc/OH	HBAN	810.946	10.860	8,807	0.0546%	2.21%	7.06%	0.0012%	0.0039%
Health Care REIT Inc	HCN	350.104	72.020	25,214	0.1563%	4.58%	5.13%	0.0072%	0.0080%
Biogen Inc	BIIB	235.230	373.930	87,960	0.0000%	N/A	17.01%	n/a	0.0000%
Linear Technology Corp	LLTC	239.194	46.130	11,034	0.0684%	2.60%	9.35%	0.0018%	0.0064%
Range Resources Corp	RRC	169.072	63.560	10,746	0.0666%	0.25%	17.18%	0.0002%	0.0114%
Noble Corp plc	NE	241.955	17.310	4,188	0.0000%	8.67%	-5.53%	0.0000%	0.0000%
Northern Trust Corp	NTRS	233.369	73.150	17,071	0.1058%	1.97%	12.94%	0.0021%	0.0137%
Paychex Inc	PAYX	363.228	48.390	17,577	0.1090%	3.14%	10.62%	0.0034%	0.0116%
People's United Financial Inc	PBCT	308.216	15.110	4,657	0.0000%	4.43%	N/A	0.0000%	n/a
Patterson Cos Inc	PDCO	103.117	46.955	4,842	0.0300%	1.87%	9.78%	0.0006%	0.0029%
Pall Corp	PLL	106.645	97.320	10,379	0.0643%	1.25%	10.99%	0.0008%	0.0071%
QUALCOMM Inc	QCOM	1,629.569	68.000	110,811	0.6869%	2.82%	10.46%	0.0194%	0.0718%
Roper Technologies Inc	ROP	100.445	168.170	16,892	0.1047%	0.59%	13.43%	0.0006%	0.0141%
Ross Stores Inc	ROST	206.895	98.880	20,458	0.1268%	0.95%	13.50%	0.0012%	0.0171%
AutoNation Inc	AN	114.025	61.550	7,018	0.0000%	N/A	12.32%	n/a	0.0000%
Starbucks Corp	SBUX	1,500.500	49.580	74,395	0.4612%	1.29%	17.68%	0.0060%	0.0815%
KeyCorp	KEY	843.751	14.450	12,192	0.0756%	1.80%	6.68%	0.0014%	0.0050%
Staples Inc	SPLS	640.487	16.320	10,453	0.0648%	2.94%	0.17%	0.0019%	0.0001%
State Street Corp	STT	412.283	77.120	31,795	0.1971%	1.56%	9.89%	0.0031%	0.0195%
US Bancorp/MN	USB	1,782.705	42.870	76,425	0.4737%	2.29%	7.70%	0.0108%	0.0365%
Symantec Corp	SYMC	682.380	24.925	17,008	0.1054%	2.41%	8.11%	0.0025%	0.0086%
T Rowe Price Group Inc	TROW	260.585	81.180	21,154	0.1311%	2.56%	11.59%	0.0034%	0.0152%
Kraft Foods Group Inc	KRFT	591.940	84.750	50,167	0.3110%	2.60%	8.16%	0.0081%	0.0254%
Waste Management Inc	WM	457.822	49.530	22,676	0.1406%	3.11%	7.90%	0.0044%	0.0111%
CBS Corp	CBS	457.486	62.130	28,424	0.1762%	0.97%	14.94%	0.0017%	0.0263%
Actavis plc	ACT	392.769	282.860	111,099	0.0000%	N/A	15.48%	n/a	0.0000%
Whole Foods Market Inc	WFM	360.763	47.760	17,230	0.1068%	1.09%	12.90%	0.0012%	0.0138%
Constellation Brands Inc	STZ	171.374	115.940	19,869	0.1232%	1.07%	10.07%	0.0013%	0.0124%
Xilinx Inc	XLNX	261.437	43.360	11,336	0.0703%	2.86%	9.24%	0.0020%	0.0065%
DENTSPLY International Inc	XRAY	139.854	51.000	7,133	0.0442%	0.57%	9.50%	0.0003%	0.0042%
Zions Bancorporation	ZION	203.066	28.335	5,754	0.0357%	0.85%	8.47%	0.0003%	0.0030%
Invesco Ltd	IVZ	430.706	41.420	17,840	0.1106%	2.61%	12.56%	0.0029%	0.0139%
Intuit Inc	INTU	276.726	100.330	27,764	0.1721%	1.00%	14.67%	0.0017%	0.0252%
Morgan Stanley	MS	1,971.678	37.310	73,563	0.4560%	1.61%	12.10%	0.0073%	0.0552%
Microchip Technology Inc	MCHP	201.449	47.655	9,600	0.0595%	3.00%	5.10%	0.0018%	0.0030%
ACE Ltd	ACE	326.592	106.990	34,942	0.2166%	2.43%	8.44%	0.0053%	0.0183%

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
Chesapeake Energy Corp	CHK	665.123	15.770	10,489	0.0650%	2.22%	6.23%	0.0014%	0.0040%
O'Reilly Automotive Inc	ORLY	101.801	217.830	22,175	0.0000%	N/A	17.45%	n/a	0.0000%
Allstate Corp/The	ALL	408.879	69.660	28,483	0.1766%	1.72%	8.73%	0.0030%	0.0154%
FLIR Systems Inc	FLIR	139.848	30.890	4,320	0.0268%	1.42%	15.00%	0.0004%	0.0040%
Equity Residential	EQR	363.798	73.860	26,870	0.1666%	2.99%	7.35%	0.0050%	0.0122%
BorgWarner Inc	BWA	226.265	59.200	13,395	0.0830%	0.88%	11.66%	0.0007%	0.0097%
Newfield Exploration Co	NFX	162.697	39.240	6,384	0.0000%	N/A	11.00%	n/a	0.0000%
Urban Outfitters Inc	URBN	130.518	40.040	5,226	0.0000%	N/A	16.96%	n/a	0.0000%
Simon Property Group Inc	SPG	311.261	181.490	56,491	0.3502%	3.31%	7.39%	0.0116%	0.0259%
Eastman Chemical Co	EMN	148.977	76.220	11,355	0.0704%	2.10%	7.20%	0.0015%	0.0051%
AvalonBay Communities Inc	AVB	132.209	164.340	21,727	0.1347%	3.04%	7.06%	0.0041%	0.0095%
Prudential Financial Inc	PRU	454.184	81.600	37,061	0.2297%	2.84%	11.00%	0.0065%	0.0253%
United Parcel Service Inc	UPS	702.344	100.530	70,607	0.4377%	2.90%	11.57%	0.0127%	0.0506%
Apartment Investment & Management Co	AIV	156.278	37.730	5,896	0.0366%	3.18%	7.72%	0.0012%	0.0028%
Walgreens Boots Alliance Inc	WBA	1,090.756	82.930	90,456	0.5607%	1.63%	15.65%	0.0091%	0.0878%
McKesson Corp	MCK	232.845	223.400	52,018	0.3224%	0.43%	15.95%	0.0014%	0.0514%
Lockheed Martin Corp	LMT	314.761	186.600	58,734	0.3641%	3.22%	7.97%	0.0117%	0.0290%
AmerisourceBergen Corp	ABC	219.605	114.300	25,101	0.1556%	1.01%	18.58%	0.0016%	0.0289%
Cameron International Corp	CAM	191.406	54.820	10,493	0.0000%	N/A	6.20%	n/a	0.0000%
Capital One Financial Corp	COF	549.458	80.850	44,424	0.2754%	1.98%	6.85%	0.0054%	0.0189%
Waters Corp	WAT	82.677	125.190	10,350	0.0000%	N/A	9.31%	n/a	0.0000%
Dollar Tree Inc	DLTR	205.760	76.410	15,722	0.0000%	N/A	15.12%	n/a	0.0000%
Darden Restaurants Inc	DRI	125.792	63.770	8,022	0.0497%	3.45%	12.65%	0.0017%	0.0063%
SanDisk Corp	SNDK	207.888	66.940	13,916	0.0863%	1.79%	10.32%	0.0015%	0.0089%
Diamond Offshore Drilling Inc	DO	137.159	33.470	4,591	0.0000%	1.49%	-4.00%	0.0000%	0.0000%
NetApp Inc	NTAP	311.758	36.250	11,301	0.0701%	1.82%	11.16%	0.0013%	0.0078%
Citrix Systems Inc	CTXS	160.092	67.160	10,752	0.0000%	N/A	14.14%	n/a	0.0000%
Goodyear Tire & Rubber Co/The	GT	269.903	28.365	7,656	0.0000%	0.85%	N/A	0.0000%	n/a
DaVita HealthCare Partners Inc	DVA	214.941	81.100	17,432	0.0000%	N/A	11.70%	n/a	0.0000%
Hartford Financial Services Group Inc/The	HIG	419.929	40.770	17,121	0.1061%	1.77%	9.00%	0.0019%	0.0096%
Iron Mountain Inc	IRM	210.555	34.490	7,262	0.0450%	5.51%	12.33%	0.0025%	0.0056%
Estee Lauder Cos Inc/The	EL	230.125	81.290	18,707	0.1160%	1.18%	10.30%	0.0014%	0.0119%
Lorillard Inc	LO	360.328	69.860	25,173	0.1560%	3.78%	8.64%	0.0059%	0.0135%
Yahoo! Inc	YHOO	938.193	42.565	39,934	0.0000%	N/A	10.60%	n/a	0.0000%
Principal Financial Group Inc	PFG	294.386	51.120	15,049	0.0933%	2.97%	13.50%	0.0028%	0.0126%
Allegheny Technologies Inc	ATI	109.204	33.990	3,712	0.0230%	2.12%	16.10%	0.0005%	0.0037%
Stericycle Inc	SRCL	85.216	133.430	11,370	0.0000%	N/A	15.33%	n/a	0.0000%
Universal Health Services Inc	UHS	91.790	116.950	10,735	0.0665%	0.34%	9.03%	0.0002%	0.0060%
E*TRADE Financial Corp	ETFC	289.851	28.790	8,345	0.0000%	N/A	18.52%	n/a	0.0000%
Skyworks Solutions Inc	SWKS	191.035	92.250	17,623	0.1092%	0.56%	19.48%	0.0006%	0.0213%
National Oilwell Varco Inc	NOV	394.382	54.410	21,458	0.0000%	3.38%	-5.25%	0.0000%	0.0000%
Quest Diagnostics Inc	DGX	143.636	71.420	10,258	0.0636%	2.13%	10.22%	0.0014%	0.0065%
Rockwell Automation Inc	ROK	135.444	118.600	16,064	0.0996%	2.19%	8.91%	0.0022%	0.0089%
American Tower Corp	AMT	423.089	94.530	39,995	0.2479%	1.78%	15.67%	0.0044%	0.0388%
Regeneron Pharmaceuticals Inc	REGN	101.306	457.460	46,343	0.0000%	N/A	19.55%	n/a	0.0000%
Amazon.com Inc	AMZN	465.681	421.780	196,415	0.0000%	N/A	40.35%	n/a	0.0000%
Ralph Lauren Corp	RL	61.433	133.410	8,196	0.0508%	1.50%	10.36%	0.0008%	0.0053%
Boston Properties Inc	BXP	153.402	132.310	20,297	0.1258%	1.97%	7.86%	0.0025%	0.0099%
Amphenol Corp	APH	310.474	55.370	17,191	0.1066%	0.90%	10.73%	0.0010%	0.0114%
Pioneer Natural Resources Co	PXD	149.377	172.780	25,809	0.0000%	0.05%	-3.80%	0.0000%	0.0000%
Valero Energy Corp	VLO	514.029	56.900	29,248	0.0000%	2.81%	-2.33%	0.0000%	0.0000%
L-3 Communications Holdings Inc	LLL	82.360	114.910	9,464	0.0587%	2.26%	9.22%	0.0013%	0.0054%
Western Union Co/The	WU	516.311	20.280	10,471	0.0649%	3.06%	7.38%	0.0020%	0.0048%
CH Robinson Worldwide Inc	CHRW	147.856	64.390	9,520	0.0590%	2.36%	11.04%	0.0014%	0.0065%

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

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Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
Accenture PLC	ACN	626.255	92.650	58,023	0.3597%	2.20%	10.30%	0.0079%	0.0370%
Yum! Brands Inc	YUM	432.401	85.960	37,169	0.2304%	1.91%	11.31%	0.0044%	0.0261%
Prologis Inc	PLD	521.176	40.200	20,951	0.1299%	3.58%	7.91%	0.0047%	0.0103%
FirstEnergy Corp	FE	421.985	35.910	15,153	0.0939%	4.01%	0.31%	0.0038%	0.0003%
VeriSign Inc	VRSN	116.434	63.510	7,395	0.0000%	N/A	10.67%	n/a	0.0000%
Quanta Services Inc	PWR	204.495	28.910	5,912	0.0000%	N/A	10.58%	n/a	0.0000%
Ameren Corp	AEE	242.635	40.940	9,933	0.0616%	4.01%	7.15%	0.0025%	0.0044%
Henry Schein Inc	HSIC	83.618	137.100	11,464	0.0000%	N/A	11.10%	n/a	0.0000%
Broadcom Corp	BRCM	549.000	44.205	24,269	0.1504%	1.27%	14.50%	0.0019%	0.0218%
NVIDIA Corp	NVDA	553.172	22.195	12,278	0.0761%	1.53%	9.70%	0.0012%	0.0074%
Sealed Air Corp	SEE	211.253	45.600	9,633	0.0597%	1.14%	9.53%	0.0007%	0.0057%
Cognizant Technology Solutions Corp	CTSH	610.499	58.540	35,739	0.0000%	N/A	15.97%	n/a	0.0000%
Intuitive Surgical Inc	ISRG	36.858	495.980	18,281	0.0000%	N/A	11.80%	n/a	0.0000%
CONSOL Energy Inc	CNX	228.652	32.480	7,427	0.0460%	0.77%	12.40%	0.0004%	0.0057%
Affiliated Managers Group Inc	AMG	54.717	226.130	12,373	0.0000%	N/A	15.15%	n/a	0.0000%
Aetna Inc	AET	349.200	106.870	37,319	0.2313%	0.94%	11.90%	0.0022%	0.0275%
Republic Services Inc	RSG	351.347	40.630	14,275	0.0885%	2.76%	5.15%	0.0024%	0.0046%
eBay Inc	EBAY	1,214.822	58.260	70,776	0.0000%	N/A	12.61%	n/a	0.0000%
Goldman Sachs Group Inc/The	GS	432.394	196.420	84,931	0.5265%	1.32%	14.90%	0.0070%	0.0785%
Sempra Energy	SRE	247.339	106.170	26,260	0.1628%	2.64%	8.92%	0.0043%	0.0145%
Moody's Corp	MCO	202.052	107.520	21,725	0.1347%	1.26%	13.50%	0.0017%	0.0182%
Priceline Group Inc/The	PCLN	51.835	1,237.810	64,162	0.0000%	N/A	19.03%	n/a	0.0000%
F5 Networks Inc	FFIV	71.655	122.020	8,743	0.0000%	N/A	15.42%	n/a	0.0000%
Akamai Technologies Inc	AKAM	178.856	73.780	13,196	0.0000%	N/A	15.80%	n/a	0.0000%
QEP Resources Inc	QEP	176.661	22.500	3,975	0.0246%	0.36%	15.00%	0.0001%	0.0037%
Reynolds American Inc	RAI	532.013	73.300	38,997	0.2417%	3.66%	9.70%	0.0088%	0.0235%
Devon Energy Corp	DVN	411.042	68.210	28,037	0.1738%	1.41%	4.32%	0.0024%	0.0075%
Google Inc	GOOGL	288.265	548.770	158,191	0.0000%	N/A	16.28%	n/a	0.0000%
Red Hat Inc	RHT	183.319	75.260	13,797	0.0000%	N/A	17.13%	n/a	0.0000%
Hudson City Bancorp Inc	HCBK	528.935	9.300	4,919	0.0000%	N/A	-3.00%	n/a	0.0000%
Allegion PLC	ALLE	95.677	61.150	5,851	0.0363%	0.65%	13.70%	0.0002%	0.0050%
Netflix Inc	NFLX	60.623	556.500	33,737	0.0000%	N/A	36.41%	n/a	0.0000%
Agilent Technologies Inc	A	335.810	41.370	13,892	0.0861%	0.97%	5.90%	0.0008%	0.0051%
Anthem Inc	ANTM	264.536	150.930	39,926	0.2475%	1.66%	10.03%	0.0041%	0.0248%
CME Group Inc/IL	CME	337.549	90.910	30,687	0.1902%	2.20%	12.38%	0.0042%	0.0235%
Juniper Networks Inc	JNPR	405.790	26.430	10,725	0.0665%	1.51%	11.40%	0.0010%	0.0076%
BlackRock Inc	BLK	164.952	363.940	60,033	0.3721%	2.40%	15.05%	0.0089%	0.0560%
DTE Energy Co	DTE	179.330	79.630	14,280	0.0885%	3.47%	5.02%	0.0031%	0.0044%
NASDAQ OMX Group Inc/The	NDAQ	169.188	48.630	8,228	0.0510%	2.06%	8.90%	0.0010%	0.0045%
Philip Morris International Inc	PM	1,549.093	83.470	129,303	0.8015%	4.79%	4.29%	0.0384%	0.0344%
Time Warner Cable Inc	TWC	282.518	155.520	43,937	0.2724%	1.93%	11.75%	0.0053%	0.0320%
Salesforce.com inc	CRM	655.556	72.820	47,738	0.0000%	N/A	26.88%	n/a	0.0000%
MetLife Inc	MET	1,119.239	51.290	57,406	0.3558%	2.92%	7.15%	0.0104%	0.0254%
Monsanto Co	MON	476.103	113.960	54,257	0.3363%	1.72%	8.92%	0.0058%	0.0300%
Coach Inc	COH	275.831	38.210	10,540	0.0653%	3.53%	10.72%	0.0023%	0.0070%
Fluor Corp	FLR	146.573	60.140	8,815	0.0546%	1.40%	5.67%	0.0008%	0.0031%
Dun & Bradstreet Corp/The	DNB	36.031	127.670	4,600	0.0285%	1.45%	10.25%	0.0004%	0.0029%
Edwards Lifesciences Corp	EW	107.558	126.650	13,622	0.0000%	N/A	15.20%	n/a	0.0000%
Ameriprise Financial Inc	AMP	182.312	125.280	22,840	0.1416%	2.14%	11.65%	0.0030%	0.0165%
Xcel Energy Inc	XEL	506.660	33.910	17,181	0.1065%	3.77%	5.00%	0.0040%	0.0053%
Rockwell Collins Inc	COL	132.269	97.330	12,874	0.0798%	1.36%	10.44%	0.0011%	0.0083%
FMC Technologies Inc	FTI	230.912	44.100	10,183	0.0000%	N/A	10.15%	n/a	0.0000%
Zimmer Holdings Inc	ZMH	170.006	109.840	18,673	0.1158%	0.80%	10.24%	0.0009%	0.0118%
CBRE Group Inc	CBG	332.958	38.340	12,766	0.0000%	N/A	11.80%	n/a	0.0000%

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
MasterCard Inc	MA	1,116.113	90.210	100,685	0.6241%	0.71%	17.50%	0.0044%	0.1092%
GameStop Corp	GME	107.769	38.540	4,153	0.0257%	3.74%	14.93%	0.0010%	0.0038%
CarMax Inc	KMX	208.870	68.110	14,226	0.0000%	N/A	15.31%	n/a	0.0000%
Intercontinental Exchange Inc	ICE	111.754	224.530	25,092	0.1555%	1.16%	17.61%	0.0018%	0.0274%
Fidelity National Information Services Inc	FIS	283.306	62.490	17,704	0.1097%	1.66%	12.42%	0.0018%	0.0136%
Chipotle Mexican Grill Inc	CMG	31.047	621.340	19,291	0.0000%	N/A	20.59%	n/a	0.0000%
MeadWestvaco Corp	MWV	167.441	48.800	8,171	0.0507%	2.05%	11.00%	0.0010%	0.0056%
Pepco Holdings Inc	POM	252.815	25.980	6,568	0.0407%	4.16%	5.00%	0.0017%	0.0020%
Wynn Resorts Ltd	WYNN	101.525	111.070	11,276	0.0699%	1.80%	11.00%	0.0013%	0.0077%
DIRECTV	DTV	502.801	90.705	45,607	0.0000%	N/A	2.25%	n/a	0.0000%
Hospira Inc	HSP	172.779	87.290	15,082	0.0000%	N/A	18.30%	n/a	0.0000%
Assurant Inc	AIZ	68.866	61.460	4,233	0.0262%	1.76%	7.71%	0.0005%	0.0020%
NRG Energy Inc	NRG	337.175	25.240	8,510	0.0528%	2.30%	31.52%	0.0012%	0.0166%
Genworth Financial Inc	GNW	497.389	8.790	4,372	0.0000%	N/A	5.00%	n/a	0.0000%
Regions Financial Corp	RF	1,342.806	9.830	13,200	0.0818%	2.44%	2.77%	0.0020%	0.0023%
Teradata Corp	TDC	145.150	43.990	6,385	0.0000%	N/A	10.13%	n/a	0.0000%
Mosaic Co/The	MOS	347.948	44.000	15,310	0.0949%	2.50%	9.35%	0.0024%	0.0089%
Expedia Inc	EXPE	113.920	94.230	10,735	0.0665%	0.76%	14.72%	0.0005%	0.0098%
Discovery Communications Inc	DISCA	149.129	32.360	4,826	0.0000%	N/A	16.10%	n/a	0.0000%
CF Industries Holdings Inc	CF	47.902	287.470	13,770	0.0854%	2.09%	15.80%	0.0018%	0.0135%
Viacom Inc	VIAB	346.593	69.450	24,071	0.1492%	1.90%	10.98%	0.0028%	0.0164%
Wyndham Worldwide Corp	WYN	120.045	85.400	10,252	0.0635%	1.97%	10.00%	0.0013%	0.0064%
Google Inc	GOOG	341.692	537.340	183,605	0.0000%	N/A	16.28%	n/a	0.0000%
Spectra Energy Corp	SE	671.320	37.250	25,007	0.1550%	3.97%	6.35%	0.0062%	0.0098%
First Solar Inc	FSLR	100.791	59.670	6,014	0.0000%	N/A	-3.81%	n/a	0.0000%
Mead Johnson Nutrition Co	MJN	202.553	95.920	19,429	0.1204%	1.72%	9.72%	0.0021%	0.0117%
Ensco PLC	ESV	234.291	27.280	6,391	0.0000%	2.20%	-3.50%	0.0000%	0.0000%
TE Connectivity Ltd	TEL	406.591	66.550	27,059	0.1677%	1.74%	10.45%	0.0029%	0.0175%
Discover Financial Services	DFS	442.505	57.970	25,652	0.1590%	1.93%	9.38%	0.0031%	0.0149%
TripAdvisor Inc	TRIP	130.708	80.490	10,521	0.0000%	N/A	23.38%	n/a	0.0000%
Dr Pepper Snapple Group Inc	DPS	191.731	74.580	14,299	0.0886%	2.57%	6.98%	0.0023%	0.0062%
Scripps Networks Interactive Inc	SNI	94.047	69.860	6,570	0.0407%	1.32%	8.81%	0.0005%	0.0036%
Visa Inc	V	1,957.431	66.050	129,288	0.8014%	0.73%	17.77%	0.0058%	0.1424%
Xylem Inc/NY	XYL	181.371	37.020	6,714	0.0416%	1.52%	11.45%	0.0006%	0.0048%
Marathon Petroleum Corp	MPC	272.986	98.570	26,908	0.1668%	2.03%	6.57%	0.0034%	0.0110%
Level 3 Communications Inc	LVLT	354.151	55.940	19,811	0.0000%	N/A	29.15%	n/a	0.0000%
Tractor Supply Co	TSCO	136.480	86.060	11,745	0.0728%	0.74%	15.38%	0.0005%	0.0112%
Transocean Ltd	RIG	363.341	18.820	6,838	0.0000%	3.19%	-14.73%	0.0000%	0.0000%
Essex Property Trust Inc	ESS	65.125	221.950	14,454	0.0896%	2.60%	7.40%	0.0023%	0.0066%
General Growth Properties Inc	GGP	885.439	27.400	24,261	0.1504%	2.48%	7.72%	0.0037%	0.0116%
Realty Income Corp	O	232.539	46.970	10,922	0.0677%	4.84%	3.42%	0.0033%	0.0023%
Seagate Technology PLC	STX	317.382	58.720	18,637	0.1155%	3.68%	6.80%	0.0042%	0.0079%
Western Digital Corp	WDC	231.032	97.740	22,581	0.1400%	2.05%	5.03%	0.0029%	0.0070%
Fossil Group Inc	FOSL	49.710	83.980	4,175	0.0000%	N/A	12.42%	n/a	0.0000%
Lam Research Corp	LRCX	158.325	75.580	11,966	0.0742%	0.95%	7.83%	0.0007%	0.0058%
Mohawk Industries Inc	MHK	73.089	173.500	12,681	0.0000%	N/A	10.95%	n/a	0.0000%
Pentair PLC	PNR	179.639	62.150	11,165	0.0692%	2.06%	15.06%	0.0014%	0.0104%
Monster Beverage Corp	MNST	170.016	137.110	23,311	0.0000%	N/A	18.34%	n/a	0.0000%
Vertex Pharmaceuticals Inc	VRTX	243.613	123.280	30,033	0.0000%	N/A	24.92%	n/a	0.0000%
Facebook Inc	FB	2,248.896	78.770	177,146	0.0000%	N/A	28.25%	n/a	0.0000%
United Rentals Inc	URI	96.970	96.580	9,365	0.0000%	N/A	16.41%	n/a	0.0000%
Delta Air Lines Inc	DAL	816.297	44.640	36,439	0.2259%	0.81%	21.91%	0.0018%	0.0495%
Navient Corp	NAVI	389.021	19.540	7,601	0.0000%	3.28%	N/A	0.0000%	n/a
Mallinckrodt PLC	MNK	116.482	113.180	13,183	0.0000%	N/A	26.54%	n/a	0.0000%

Montana-Dakota Utilities Co.

Market DCF Calculation

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.35%**	**2.50%**	**9.90%**	**12.40%**

	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted BEst Long-Term Growth Estimate
Alcoa Inc	AA	1222.382	13.42	16,404	0.1017%	0.89%	6.67%	0.0009%	0.0068%
Keurig Green Mountain Inc	GMCR	161.675	116.370	18,814	0.1166%	0.99%	15.67%	0.0012%	0.0183%
Macerich Co/The	MAC	158.242	81.760	12,938	0.0802%	3.18%	6.16%	0.0026%	0.0049%
Martin Marietta Materials Inc	MLM	67.307	142.650	9,601	0.0595%	1.12%	21.29%	0.0007%	0.0127%
Alexion Pharmaceuticals Inc	ALXN	199.577	169.230	33,774	0.0000%	N/A	23.41%	n/a	0.0000%
Endo International PLC	ENDP	178.740	84.065	15,026	0.0000%	N/A	9.78%	n/a	0.0000%
News Corp	NWSA	381.096	15.780	6,014	0.0000%	N/A	11.78%	n/a	0.0000%
Crown Castle International Corp	CCI	333.762	83.530	27,879	0.1728%	3.93%	21.60%	0.0068%	0.0373%
Delphi Automotive PLC	DLPH	288.738	83.000	23,965	0.1486%	1.20%	13.74%	0.0018%	0.0204%
Michael Kors Holdings Ltd	KORS	200.756	61.860	12,419	0.0000%	N/A	20.37%	n/a	0.0000%
Alliance Data Systems Corp	ADS	62.234	297.310	18,503	0.0000%	N/A	14.02%	n/a	0.0000%
Garmin Ltd	GRMN	208.077	45.190	9,403	0.0583%	4.51%	7.20%	0.0026%	0.0042%
Cimarex Energy Co	XEC	87.665	124.400	10,906	0.0000%	0.51%	-7.49%	0.0000%	0.0000%
Zoetis Inc	ZTS	500.665	44.420	22,240	0.1379%	0.75%	11.83%	0.0010%	0.0163%
Equinix Inc	EQIX	56.923	255.930	14,568	0.0903%	2.64%	17.00%	0.0024%	0.0154%
Discovery Communications Inc	DISCK	278.089	30.23	8,407	0.0000%	N/A	16.10%	n/a	0.0000%
Average for Companies Paying Dividends with Positive BEst Long-Term Growth Estimates						**2.21%**	**9.88%**		

Notes:
[1] Equals sum of Column [11]
[2] Equals Column [1] x (1 + 0.625 x Column [3])
[3] Equals sum of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: Bloomberg Finance L.P.
[6] Source: Bloomberg Finance L.P.
[7] Equals Column [5] x Column [6]
[8] Equals percent of sum of Column [7] if Current Dividend Yield does not equal "n/a" and BEst Long-Term Growth Estimate does not equal "n/a" and is greater than 0%
[9] Source: Bloomberg Finance L.P.
[10] Source: Bloomberg Finance L.P.
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Capital Structures as of March 31, 2015

$ millions

		2		4		6		8			
Company	Ticker	Short-Term Debt	%	Long-Term Debt	%	Preferred Stock	%	Common Equity	%	Total Capital	
ALLETE, Inc.	ALE	$ 300	0.01%	$ 1,376,100	43.75%	-	0.00%	$ 1,768,900	56.24%	$ 3,145,300	
Alliant Energy Corporation	LNT	$ 41,500	0.56%	$ 3,789,700	51.02%	-	0.00%	$ 3,597,100	48.42%	$ 7,428,300	1/
Ameren Corporation	AEE	$ 955,000	6.87%	$ 6,240,000	44.90%	-	0.00%	$ 6,704,000	48.23%	$ 13,899,000	1/
American Electric Power Company, Inc.	AEP	$ 855,000	2.29%	$ 19,229,000	51.52%	-	0.00%	$ 17,241,000	46.19%	$ 37,325,000	1/
Empire District Electric Company	EDE	$ 53,000	3.22%	$ 803,446	48.81%	-	0.00%	$ 789,458	47.97%	$ 1,645,904	1/
Great Plains Energy Inc.	GXP	$ 717,000	9.22%	$ 3,487,900	44.86%	-	0.00%	$ 3,570,000	45.92%	$ 7,774,900	1/
OGE Energy Corporation	OGE	$ 109,900	1.80%	$ 2,755,400	45.12%	-	0.00%	$ 3,241,800	53.08%	$ 6,107,100	1/
Otter Tail Corporation	OTTR	$ 48,652	4.29%	$ 498,641	43.99%	-	0.00%	$ 586,274	51.72%	$ 1,133,567	1/
PNM Resources, Inc.	PNM	$ 100,000	2.54%	$ 2,125,007	53.94%	-	0.00%	$ 1,714,392	43.52%	$ 3,939,399	1/
TECO Energy, Inc.	TE	$ 206,000	3.21%	$ 3,627,700	56.50%	-	0.00%	$ 2,587,300	40.29%	$ 6,421,000	1/
Westar Energy, Inc.	WR	$ 425,400	4.88%	$ 3,257,246	37.37%	1,725,000	19.79%	$ 3,307,790	37.95%	$ 8,715,436	1/
Xcel Energy Inc.	XEL	$ 969,000	4.22%	$ 11,756,869	51.25%	-	0.00%	$ 10,214,870	44.53%	$ 22,940,739	1/
Median			**3.21%**		**46.97%**		**0.00%**		**47.08%**		
Montana-Dakota Utilities Co.											
- Montana Electric Dist. Operations		$ 37,100	8.11%	$ 392,969	41.14%	15,309	1.24%	$ 478,047	49.52%	$ 923,424	2/

1/ Source: SNL Financial LC; data as of March 31, 2015
2/ Source: Montana-Dakota Utilities Co.; Capital Structure Pro Forma 2015

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

Before the Public Service Commission of Montana

Docket No. D2015.6.___

Direct Testimony
of
Jay Skabo

1 **Q. Please state your name and business address.**

2 A. My name is Jay Skabo and my business address is 400 North
3 Fourth Street, Bismarck, North Dakota 58501.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am the Vice President of Electric Supply for Montana-Dakota
6 Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

7 **Q. Please describe your duties and responsibilities with Montana-**
8 **Dakota.**

9 A. My responsibilities include power production and transmission,
10 system operations and planning, and electric dispatch.

11 **Q. Please outline your educational and professional background.**

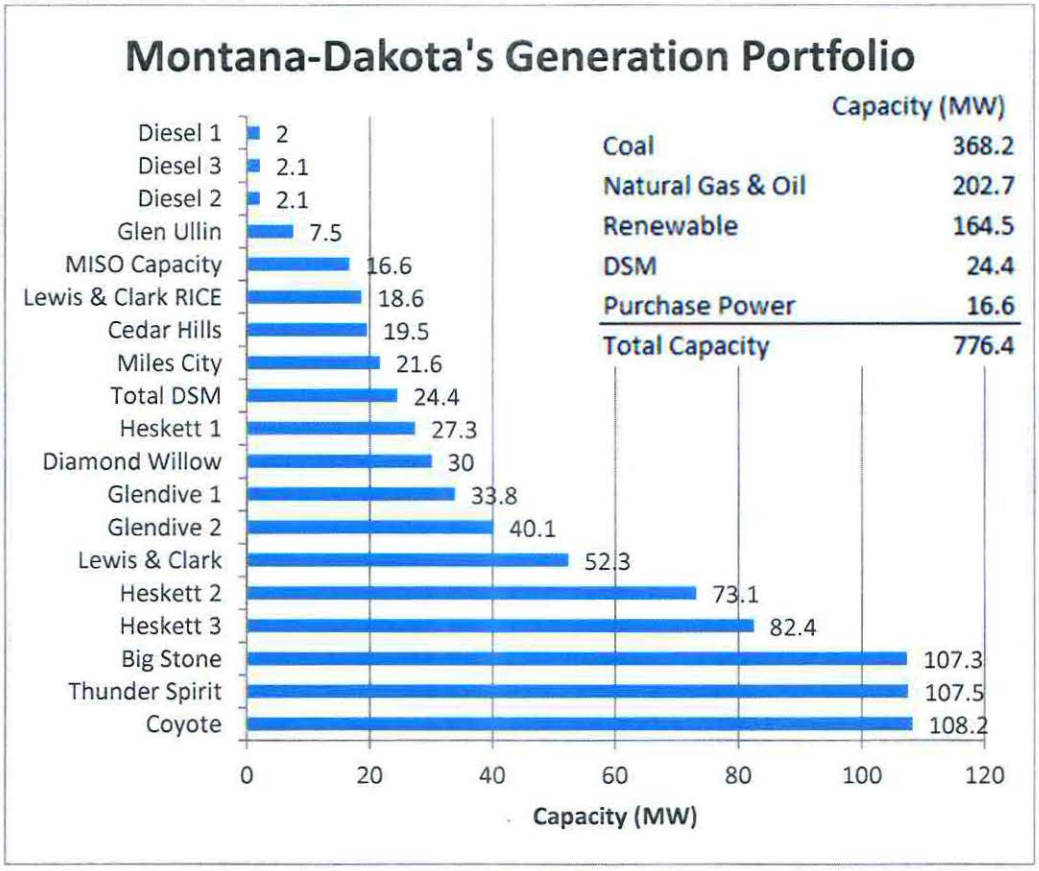
12 A. I hold Bachelor's Degrees in Chemistry from Dickinson State
13 University and Chemical Engineering from the University of North Dakota.
14 My work experience includes three and half years as the Environmental
15 Manager at Montana-Dakota; one and a half years as a Region Manager
16 overseeing gas and electric crews, service technicians, and office
17 personnel in constructing and maintaining our gas and electric systems.

1 In 2008, I became Vice President of Operations. In January 2014, I
2 assumed my current position. Prior to joining Montana-Dakota, I was the
3 general manager of an industrial waste processing and disposal facility.
4 Q. **Have you testified in other proceedings before regulatory bodies?**
5 A. Yes, I have testified before the North Dakota and Montana Public
6 Service Commissions.
7 **Q. What is the purpose of your testimony?**
8 A. The purpose of my testimony is to provide information regarding
9 Montana-Dakota's generation portfolio, recent generation and
10 transmission investments and how these investments will serve customers
11 well into the future.
12 **Q. Please describe Montana-Dakota's current portfolio of generation**
13 **assets used to serve customers and changes transpiring in 2015.**
14 A. Montana-Dakota's existing generation serving its interconnected
15 electric system is comprised of baseload coal-fired generation at the
16 Heskett Station (Units I and II), the Lewis & Clark Station, Montana-
17 Dakota's shares of the Coyote and Big Stone Stations, and natural gas-
18 fired peaking generation at Glendive (Units I and II), Miles City, and
19 Heskett Unit III. Montana-Dakota also owns the Diamond Willow I,
20 Diamond Willow II and Cedar Hills wind farms, three two (2) MW portable
21 diesel units, and the Glen Ullin Station 6 waste heat generating unit
22 serving the Integrated System. The remainder of the capacity
23 requirements had been provided by a capacity contract with We Energies

(which expired in May of 2015) and energy purchases from the MISO energy market. To meet growing needs and increase reliability, to replace the expiring We Energies contract and to reduce reliance on the MISO energy market, Montana-Dakota identified the following resources through the Integrated Resource Planning process as the best options to meet the objectives noted above:

- Heskett III, an 88 MW simple cycle gas fired turbine was placed into service in August 2014. This unit is co-located with the Heskett I and II coal fired units in Mandan, North Dakota. Co-locating at an existing power plant substantially reduces costs. It eliminates the need for purchasing additional land, and reduces the amount of additional staff. Heskett III only required two new employees to be added.
- A 18.6 MW natural gas-fired reciprocating engine project comprised of two 9.3 MW Wartsilla generating units is currently under construction and is co-located with the Lewis & Clark Station in Sidney, Montana. This generator is referred to as the Lewis & Clark RICE Project. Siting this unit at an existing plant also takes advantage of the cost savings of co-location.
- A 107.5 wind project known as Thunder Spirit Wind located near Hettinger, North Dakota, is currently under construction.

Following is a graphical presentation of the generation portfolio and associated capacity of each unit.



Mr. Darcy Neigum will provide additional details regarding the selection of each of the new generating units including the justification of need for each project.

Q. What impact have recent EPA regulations had on Montana-Dakota's generation portfolio?

A. The two primary EPA regulations affecting Montana-Dakota's investments included in this rate case are 1) the Mercury and Air Toxics Standards Rule (MATS Rule) and 2) the Regional Haze Rule.

Q. Would you please describe the MATS Rule?

1 A. The MATS Rule, published as a final rule on February 16, 2012,
2 regulates hazardous air pollutant (HAP) emissions from coal- and oil-fired
3 electric generating units. The rule became effective on April 16, 2012, and
4 compliance with the MATS emission limits was required by April 16, 2015,
5 with the opportunity for a one- year extension if required for the installation
6 of the selected air pollution control systems.
7 The rule includes emissions standards for mercury (Hg), non-Hg
8 trace metals, and acid gas emissions from existing coal-fired boilers such
9 as at the Lewis & Clark Station. Work practice standards are also
10 included for control of organic HAP emissions. For the non-Hg metals, the
11 rule includes alternative emission limits for filterable particulate matter
12 (FPM), total non-Hg HAP metals, and individual HAP metals. For the acid
13 gases, the rule includes alternative emission standards for either
14 hydrochloric acid (HCl) or SO_2 as a surrogate to demonstrate compliance
15 for all acid gas emissions.
16 **Q. What generating units were affected by the MATS Rule?**
17 A. The Lewis & Clark Station, an existing single-unit, 50-MW lignite-
18 fired facility located near Sidney, Montana, and the Big Stone Plant
19 located near Big Stone City, South Dakota, and Coyote Station located
20 near Beulah, North Dakota, require equipment upgrades in order to
21 comply with the MATS Rule. Lewis & Clark is a low cost baseload
22 resource critical in meeting Montana-Dakota's customers' energy and
23 capacity requirements. It provides important voltage and reliability support

1 to the region, and helps mitigate load restrictions during outages of other
2 bulk electric system facilities. Montana-Dakota has gone through several
3 iterations, including natural gas co-firing, in finding an economic solution to
4 meeting the MATS Rule in order to avoid shuttering this plant. Ultimately,
5 in September of 2014, Montana-Dakota initiated a study with URS
6 Corporation (URS), a consulting engineer experienced in modifying wet
7 scrubbers similar to the Lewis & Clark Station's scrubber. Montana-Dakota
8 concluded that URS' turnkey solution, with a guarantee to achieve the
9 requirements for MATS non-mercury metals compliance, was an
10 economic solution that could be installed and placed into service in late
11 2015 and Montana-Dakota entered into an agreement with URS to design
12 and install modifications to the existing scrubber. On, January 30, 2015,
13 the Montana Department of Environmental Quality issued a one-year
14 compliance deadline extension for meeting the non-mercury hazardous air
15 pollutant metals standard. The Lewis & Clark MATS project is set to be
16 operational in December 2015 at a projected cost of $16.2 million. The
17 Integrated Resource Plan continues to support the capital investment in
18 lieu of shutting down the plant. Mr. Alan Welte will provide additional
19 details regarding the history of the compliance efforts and the Lewis &
20 Clark MATS project.
21 Activated carbon injection systems at an estimated cost of
22 approximately $4.2 million are needed to comply with the mercury limit of
23 the MATS Rule at the Coyote Station and Big Stone Plant. At Big Stone

1 Plant this equipment is being installed as part of the Air Quality Control
2 System project, which I will discuss in more detail below.
3 **Q. Were there other generating units affected by the MATS Rule?**
4 A. Yes. Reagent expenses will be also be required at the Lewis &
5 Clark Station, the Big Stone Station, the Lewis & Clark RICE units, as well
6 as the Coyote Station and Heskett I. The reagent is required as part of
7 the systems to remove regulated contaminants and will cause an increase
8 in the variable production costs with each of these plants in addition to
9 requiring additional workforce. At Heskett I, the Hg limits are currently
10 being met with the addition of Tire-Derived Fuel to the coal feed.
11 **Q. Would you now describe the upgrades required at the Big Stone**
12 **Plant in order to meet EPA's Regional Haze Rules?**
13 A. Yes. First, to provide some background information, the Big Stone
14 plant is co-owned by NorthWestern Corporation d/b/a NorthWestern
15 Energy, Montana-Dakota, and Otter Tail Power Company (Otter Tail)
16 hereinafter referred to as the Owners. Otter Tail operates the Big Stone
17 power plant (Big Stone) near Big Stone City, South Dakota. Montana-
18 Dakota's ownership share in the Big Stone Plant is 22.7 percent, and
19 therefore Montana-Dakota is responsible for 22.7 percent of the costs of
20 operating the plant including the investments necessary to comply with the
21 EPA's rules.
22 The Clean Air Act, 42 U.S.C. §7479, mandates a national goal of
23 remedying and preventing visibility impairment from man-made air

1 pollution in specified areas (referred to as Class I) of the United States
2 which include national parks and wilderness areas. In 1999, EPA
3 promulgated the Regional Haze Rule (40 CFR Part 51), which was revised
4 in 2005, to implement this requirement of the Clean Air Act. The Regional
5 Haze Rule includes the requirement to install the Best Available Retrofit
6 Technology (BART) on major generating sources, including existing
7 electric generating units that were placed into operation between 1962
8 and 1977. Because the Big Stone Plant began commercial operation on
9 May 1, 1975, it was subject to the requirements of the Regional Haze Rule
10 for the installation of BART. Conversely, Heskett I & II, Lewis & Clark, and
11 Coyote, were not included in this phase of the rule, due to the dates of
12 their construction.
13 **Q. How was it determined if the Big Stone Plant would be required to**
14 **install BART?**
15 A. Under the Regional Haze Rule, state environmental agencies are
16 authorized to submit a State Implementation Plan (SIP) to EPA for review
17 and approval, outlining how the state intends to bring affected sources
18 subject to jurisdiction into compliance with the rule. If a state does not
19 propose a SIP, EPA will develop a plan to control emissions from sources
20 located in that state which are shown to contribute to visibility impairment.
21 South Dakota elected to pursue adoption of a SIP through its state
22 agency, in this case the South Dakota Department of Environmental and
23 Natural Resources (DENR).

In response to the Regional Haze Rule, Otter Tail, as the operator of the Big Stone Plant, performed an evaluation of the visibility impact of the plant's operations on seven Class 1 areas in four states. Based on this evaluation, the South Dakota DENR determined the Big Stone Plant's emissions contribute to impairment of visibility in multiple Class 1 areas and therefore the plant was subject to the BART requirements of the Regional Haze Rule.

Q. How was BART determined for the Big Stone Plant?

A. Otter Tail, as agent for the owners, proposed that separated over-fired air (SOFA) technology be deployed as BART for the Big Stone Plant in its BART Technology analysis. On September 15, 2010, the South Dakota DENR, Board of Minerals and Environment, adopted Administrative Rules of South Dakota chapter 74:36:21 which imposed limits on nitrogen oxides, sulfur dioxides, and particulate matter that were substantially lower than those in the existing Big Stone Plant permit. The South Dakota Regional Haze SIP included the following as BART technologies applicable to the Big Stone Plant:

- Selective catalytic reduction technology (SCR) with separated over-fired air for control of NO_x.
- Semi-dry flue gas desulfurization for control of SO_2.
- A baghouse for control of particulate matter.

On January 21, 2011, the South Dakota DENR submitted its SIP to the EPA for review and approval. On March 29, 2012, the EPA approved the

1 South Dakota SIP and the final rule was published on April 26, 2012.
2 Under the South Dakota Regional Haze Rule, the Big Stone Plant must
3 achieve BART compliance expeditiously but no later than five years after
4 EPA's approval of the South Dakota SIP, or April 26, 2017.

5 **Q. Would the Big Stone Plant be forced to close without these**
6 **environmental upgrades?**

7 A. Yes. The plant could not operate using coal as its fuel source after
8 April 26, 2017 without the environmental upgrades adopted in the South
9 Dakota SIP.

10 **Q. What did the Owners consider when deciding whether to pursue**
11 **installation of the BART at the Big Stone Plant?**

12 A. The Owners obtained a cost estimate from the engineering firm of
13 Sargent & Lundy for the installation of the BART technology identified in
14 the South Dakota SIP at the Big Stone Plant. The initial estimate of a
15 BART compliant AQCS was $489,397,400 in 2015 dollars, with an
16 accuracy of plus or minus 20 percent. An additional cost to install
17 activated carbon injection for mercury control under the MATS Rule was
18 estimated at $5,012,700 for a total cost estimate of $494,410,100
19 including engineering, procurement, construction, supervision, and
20 management costs for the project. The Owners then compared the
21 construction and operation costs of Big Stone with the AQCS to several
22 other generation alternatives. In each instance, the assessment
23 concluded that Big Stone with the AQCS was the least cost option. In

1 May of 2012, the North Dakota Public Service Commission issued its
2 Order accepting the AQCS Project as prudent in the Company's joint
3 application with Otter Tail Power Company for an Advance Determination
4 of Prudence.

5 **Q. Did Montana-Dakota conduct any analysis of the Big Stone AQCS**
6 **and other generation alternatives specific to its generation needs?**

7 A. Yes. Montana-Dakota separately analyzed the cost effectiveness
8 of the Big Stone AQCS project beginning with its 2011 Integrated
9 Resource Plan (IRP). Montana-Dakota modeled sensitivity scenarios
10 surrounding the AQCS and various alternatives. Even when the modeled
11 cost of the AQCS was nearly doubled from its original estimate, it was still
12 selected as part of Montana-Dakota's resource plan recommended in its
13 2011 IRP.

14 **Q. What is the current status of the Big Stone AQCS project?**

15 A. The project is set to be operational in late 2015 at an estimated
16 cost of $384 million (including the MATS project). Mr. Alan Welte will
17 provide details of the AQCS project.

18 **Q. Did Montana-Dakota consider abandoning the AQCS project based**
19 **on the proposed Clean Power Plan (CPP) rule?**

20 A. This was considered by Montana-Dakota and the Owners and it
21 was quickly recognized that the plant would have been required to shut
22 down by April 26, 2017, if the emissions controls were not in place. It was
23 also determined that at the time the proposed CPP rule was published, the

1 project was fully under construction and as such, expenses had been
2 committed to the point that the loss of investment would be too significant
3 to curtail construction at that point. For example as of June 30, 2014, the
4 only major contract left to execute was for demolition services to remove
5 the old baghouse, fans and ash silo. Additional modeling also determined
6 that the investment in the AQCS was still a least cost option, even if the
7 plant was only able to run until December 31, 2019, the effective date of
8 the CPP. Further, the CPP has yet to be finalized, and is expected to
9 undergo significant modifications, and is also highly suspect of being
10 dismantled due to legal challenges. Abandoning the AQCS project when
11 it was well into construction based on the potential of a draft rule with a
12 long implementation timeframe, would have been imprudent.
13 Q. **Do you believe Montana-Dakota is positioned well for the future**
14 **given the impending Clear Air Act regulations expected to be**
15 **released by the EPA in August of this year?**
16 A. Yes I do. The investments being made today in new generation will
17 continue to serve Montana-Dakota and its customers under a carbon
18 constrained environment as what I understand is currently contemplated
19 under the Clear Power Plan regarding existing sources. We are adding
20 107.5 MW of wind resources, which will bring us to 22% carbon free
21 resources in our integrated system generation portfolio, and the Thunder
22 Spirit wind resource is expandable to 150 MW. By the end of 2015, we
23 will have 200 MW of peaking natural gas generation in our generation

1 portfolio, and we have plans to add approximately 200 MW of natural gas
2 combined cycle generation by 2020. With our current portfolio and the
3 available and planned additions, we should be positioned well to comply
4 with pending Clean Air Act, and other EPA, regulations.

5 **Q. Turning now to transmission. Would you please provide an overview**
6 **of transmission investments?**

7 A. Power is delivered over Company-owned transmission lines, as
8 well as lines owned by the Western Area Power Administration (Western)
9 and Basin Electric Power Cooperative (Basin) under long-term
10 agreements. Montana-Dakota is also a member of MISO, which allows
11 access to MISO transmission in the upper Midwest. These transmission
12 arrangements allow Montana-Dakota to efficiently serve customers
13 throughout its service territory with minimal duplication of facilities. Mr.
14 Darcy Neigum will provide information relating to the expiration of the
15 Western Agreement in December 2015 and the impacts associated with
16 Western and Basin's decision to join the Southwest Power Pool.

17 The Company has built and/or upgraded transmission lines and
18 associated infrastructure, such as substations, to reliably serve customer
19 needs. Montana electric customers' share of new investments over the
20 last five years has been about $5.2 million.

21 **Q. Does this complete your direct testimony?**

22 A. Yes, it does.

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

Before the Public Service Commission of Montana

Docket No. D2015.6.___

Direct Testimony
of
Alan L. Welte

1 **Q. Please state your name and business address.**

2 A. My name is Alan L. Welte and my business address is 400 North
3 Fourth Street, Bismarck, North Dakota 58501.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am the Director of Generation in the power production department
6 of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU
7 Resources Group, Inc.

8 **Q. Please describe your duties and responsibilities with Montana-**
9 **Dakota.**

10 A. I have overall responsibility for the day-to-day operation of
11 Montana-Dakota's electric generation facilities, represent Montana-
12 Dakota's interests in jointly owned generation facilities operated by other
13 companies, and I am also responsible for new generation development.

14 **Q. Please outline your educational and professional background.**

15 A. I hold a Bachelor's Degree in Mechanical Engineering from North
16 Dakota State University. My work experience at Montana-Dakota includes
17 eight years of experience as a plant engineer, twelve years of experience

as a plant manager, and eleven years of generation development and operational responsibilities in my current position which includes coal-fired, gas-fired, and renewable generation.

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

A. The purpose of my testimony is to describe the analysis performed to determine the optimal emissions control strategy, for the Lewis & Clark Station (Lewis & Clark), the additional pollution control equipment and modifications necessary for compliance, and the estimated cost required to demonstrate compliance with the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) Rule.

Secondly, I will discuss the Air Quality Control System project (AQCS) being installed on the Big Stone Plant (Big Stone) to comply with the South Dakota State Implementation Plan (SIP) that was developed to comply with the EPA Regional Haze Rule (40 CFR Part 51 Subpart P), as well as the equipment at Big Stone necessary for compliance with the MATS Rule. Finally, I will provide an overview of the incremental reagent costs required at several of Montana-Dakota's generating stations as a result of the MATS Rule

Q. What analysis was performed to determine the pollution control equipment additions and modifications that are required for compliance with the MATs Rule at Lewis & Clark?

A. Several diagnostic stack emissions tests were performed to determine the Lewis & Clark's baseline emissions. The stack test results

1 and continuous emissions monitoring data were analyzed to determine
2 which emissions were not meeting the applicable MATS emission limits
3 based on the existing suite of pollution control equipment. Sargent &
4 Lundy was retained by Montana-Dakota to evaluate emission control
5 technology strategies that would provide a cost effective means to
6 demonstrate compliance with the MATS Rule.

7 **Q. What was the result of comparing actual emissions to the MATS**
8 **emission limits?**

9 A. The results indicated that Lewis & Clark is already meeting the
10 MATS limits for mercury and for acid gases, as demonstrated by hydrogen
11 chloride (HCL). The results from diagnostic testing in 2011 and 2012
12 indicated that the Lewis & Clark measured emissions for filterable
13 particulate matter, total non-mercury and individual non-mercury
14 hazardous air pollutant metals all exceeded the respective MATS limits.
15 Specifically the results showed manganese would be expected to
16 consistently prevent the unit from being compliant with either the individual
17 or total non-Hg HAP metals emission limits, and FPM would be expected
18 to prevent the unit from being compliant with the FPM emission limit based
19 on the existing suite of air pollution control technologies.

20 **Q. Would you please describe Montana-Dakota's plan for complying**
21 **with the MATS Rule non-mercury hazardous pollutant metals**
22 **requirements?**

A. As part of the 2013 IRP, resource expansion modeling and analyses were performed to explore multiple options in meeting the MATS Rule by April 2015. The results of the initial modeling supported the installation and operation of a fabric filter baghouse system along with modifications to existing mist eliminator at Lewis & Clark as compared to the retirement of the plant at the end of the 2014 and a number of natural gas conversion alternatives.

Subsequent to Montana-Dakota's initial modeling results, the cost estimate for the fabric filter baghouse and mist eliminator modifications option increased from $27 million to approximately $40 million due to the need for additional equipment to prevent deposits from forming in the stack and to reflect the current regional climate for construction costs. This caused Montana-Dakota to reevaluate its initial Lewis & Clark MATS project plan as it was no longer an economical means of meeting the MATS requirements. Initially, co-firing coal with natural gas was considered to be a viable option due to pipeline capacity becoming available which was not available at the time of the 2013 resource expansion modeling. However, diagnostic test results under various natural gas/coal supply mixes indicated the natural gas co-fire option would not support MATS compliance. In September of 2014, Montana-Dakota initiated a study with URS Corporation (URS), a consulting engineering firm experienced in modifying wet scrubbers similar to the scrubber utilized at the Lewis & Clark. Upon evaluation, URS concluded

that a large fraction of the particulate matter in the scrubber slurry is re-entrained in the flue gas leaving the stack. URS determined that modifications to the existing scrubber and stack vessels will reduce the re-entrainment of scrubber slurry and the associated filterable particulate matter (FPM) sufficiently to meet the MATS non-mercury hazardous air pollutant metals compliance requirements. URS proposed a solution with guaranteed FPM reductions and that could be installed and placed into service in late 2015.

Q. What additional equipment and modifications are required for Lewis & Clark to comply with the MATS Rule?

A. To comply with the MATS Rule, Montana-Dakota will need to add the following equipment and modifications;

- Turning vanes to change the distribution of the flue gas within the stack.
- A sieve tray and mist eliminator system to increase the efficiency of removing FPM.
- A forced oxidation system to control the chemical reactions within the system and to prevent deposits from forming.

Q. Would you please describe the current status of the Lewis & Clark MATS project?

A. Montana-Dakota executed a contract with URS for them to engineer, procure and construct the project. A one year extension was granted by the Montana Department of Environmental Quality to allow for

the time needed to design, procure, construct and commission the project. URS is completing the detailed design, and procuring the equipment and construction services for the project. The construction contractor is scheduled to mobilize to Lewis & Clark in July, 2015 to begin work. The majority of the construction activities will take place during a ten week outage scheduled from September 5 to November 15, 2015. Initial operation, tuning and testing is scheduled for late November and early December, and commercial operation on about December 15, 2015. The projected cost for the project is $16 million.

Q. What additional equipment is required for Big Stone to comply with the Regional Haze and MATS Rules?

A. To comply with the Regional Haze Rule, the following equipment was added as part of the AQCS project:

- Selective catalytic reduction technology (SCR) with separated over-fired air for control of NO_x.
- Circulating dry scrubber for control of SO_2.
- A baghouse for control of particulate matter.
- Replacement Induced Draft fans.
- Modifications to the boiler tube surfaces to obtain the required SCR inlet flue gas temperature and to the boiler structure to meet the new pressure requirements for the boiler setting.
- Pebble lime and ammonia reagent handling systems.
- Waste ash handling system.

1 An activated carbon injection system was installed to comply with the
2 mercury limit of the MATS Rule. The South Dakota DENR issued a one
3 year compliance deadline extension for meeting the MATS requirements
4 to April 16, 2016.

5 **Q. What is the current status of the Big Stone AQCS project?**

6 A. Actual construction on the project is now over 99 percent
7 completed. Big Stone was shut down during the evening of February 27,
8 2015, for the start of the outage to "tie-in" all of the AQCS equipment. The
9 outage was scheduled to be completed and the unit back on line by June
10 9, 2015, but because of problems found with the plant's High Pressure
11 (HP) steam turbine during routine inspection, the outage has been
12 extended. The current projected time for the unit to return to service is
13 August 2015, an approximate 10 week extension from the original
14 schedule. This HP steam turbine work is unrelated to the AQCS Project.
15 Because of the outage extension the project budget will be negatively
16 impacted, but the project is still projected to finish on or under the $384
17 million budget estimate. Montana-Dakota's share of the total $384 million
18 capital cost estimate for the AQCS and MATS projects is $90 million.

19 Upon commercial operation of the AQCS equipment at Big Stone,
20 now expected in late 2015, the plant will require additional expenses
21 related to its ongoing operation and maintenance. While the largest of
22 these ongoing additional costs will be the emission control reagents.

1 Plant staff is expected to increase by the equivalent of
2 approximately eight full time employees needed to receive the chemical
3 reagents, prepare the chemicals for use, operate and maintain the
4 equipment and haul the ash.

5 **Q. Would you please describe the incremental reagents**
6 **necessary at Big Stone and other Company generating facilities in**
7 **order to comply with environmental regulations?**

8 A. Yes. Reagents are substances used to process emissions, with the
9 type of reagents used varying depending on the emissions control
10 equipment being installed at a specific generating facility. Reagents
11 include Powdered Activated Carbon, Pebble and Hydrated Lime, Calcium
12 Bromide, Anhydrous Ammonia and Urea. Powdered Activated Carbon
13 and Calcium Bromide are used in the reduction of mercury emissions.
14 Pebble Lime and Hydrated Lime are used for the reduction in sulfur
15 dioxide (SOx) emissions, and Anhydrous Ammonia and Urea are used for
16 the reduction of nitrogen dioxide (NO2).
17 Pebble lime, activated carbon, and anhydrous ammonia will be
18 utilized for the new emissions control equipment being installed at Big
19 Stone.
20 New equipment installed at the Coyote Station will consume
21 powdered activated carbon for the reduction of mercury emissions.
22 Powdered activated carbon and calcium bromide are used as the
23 reagents for mercury control under MATS at Lewis and Clark.

1 The majority of these reagent expenses are new costs to Montana-Dakota
2 and the incurrence of these costs will phase in overtime and are subject to
3 fluctuations due to competing market demands as well as fuel and
4 transportation costs consumed during delivery of the product. As the
5 reagent expenses are directly related to generation and are volatile in
6 nature the costs should be considered as part of the Fuel and Purchased
7 Power Adjustment as presented in Mr. Jacobson's testimony.

8 **Q. Please describe the additional staffing needed in the Power**
9 **Production and Environmental areas due to the environmental**
10 **modification and generation facility expansion projects.**

11 A. Montana-Dakota has added two full time employees and expects to
12 add two more later in 2015 to the Power Production and Environmental
13 area. These additions are needed for project development, execution,
14 and tracking as well as for on-going permitting, reporting, maintenance
15 planning, environmental and other compliance activities.

16 **Q. Does this conclude your direct testimony?**

17 A. Yes, it does.

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

Before the Public Service Commission of Montana

Docket No. D2015.6.___

Direct Testimony
of
Darcy J. Neigum

1 **Q. Please state your name and business address.**

2 A. My name is Darcy J. Neigum and my business address is 400
3 North Fourth Street, Bismarck, North Dakota 58501.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am the Director of System Operations and Planning for Montana-
6 Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources
7 Group, Inc.

8 **Q. Please describe your duties and responsibilities with Montana-**
9 **Dakota.**

10 A. I have managerial responsibility for overseeing the day-to-day
11 operations of the Company's electric control center and System
12 Operations & Planning Department. The System Operations & Planning
13 Department is responsible for preparing electric resource plans and
14 expansion studies for the Company.

15 **Q. Please outline your educational and professional background.**

16 A. I hold a Bachelor's Degree in Electrical and Electronics
17 Engineering from North Dakota State University as well as a Masters of

1 Business Administration from the University of Mary. My work experience
2 includes four years as a nuclear plant engineer, three years of experience
3 as a coal-fired power plant engineer, and eleven years of generation
4 development and operational responsibilities for coal-fired, gas-fired, and
5 renewable generation sources. I have been responsible for the
6 development of the Company's integrated resource planning activities
7 since 2008.

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

9 A. I will provide support and justification for the Company's investment
10 in incremental generation as described by Ms. Kivisto and Mr. Skabo.
11 This includes addition of the Heskett III gas turbine, the two Reciprocating
12 Internal Combustion Engines (RICE) the Company is installing at the
13 Lewis & Clark Station and the Thunder Spirit Wind Project (Thunder Spirit)
14 through the Company's integrated resource planning process. I will
15 describe the modeling used to support the required environmental
16 upgrade projects at Big Stone Station and Lewis & Clark Station and
17 finally I will discuss the changes in transmission service arrangements
18 occurring in the third quarter of 2015.

19 **Q. How has Montana-Dakota customer peak load and energy**
20 **requirements grown since 1985?**

21 A. As shown on Exhibit No. ____(DJN-1), Montana-Dakota's peak
22 load requirements on the integrated system have grown from 350 MW on
23 the summer peak in 1985 to 533 MW on the summer peak in 2014.
24 Likewise, the winter peak has increased from 331 MW to 557 MW over the

same time period. Annual energy requirements have increased by approximately 77 percent since 1985. A graphical representation is provided on page 2 of Exhibit No.___ (DJN-1) where the blue line represents the Company's annual energy requirements in MWh, the red line represents the Company's annual summer peak demands in MW and the green line represents the Company's annual winter peak demands from 1985 to 2014.

Q. Is Montana-Dakota a summer peaking or winter peaking utility?

A. As shown on Exhibit No.___(DJN-1), Montana-Dakota has historically been a summer peaking utility. However, the summers of 2013 and 2014 have been unseasonably cool as compared to seasonal averages and Montana-Dakota has seen higher winter peaks as compared to summer peaks in 2013 and 2014. This is largely due to the increased customer load since 2012 and the absence of hot summer temperatures. Montana-Dakota still believes that it is a summer peaking utility and its peak demand requirements in the Midcontinent ISO (MISO) are based upon summer load forecasts and conditions.

Q. If Montana-Dakota would have experienced summer temperatures in 2014 as experienced in 2012 what might it have seen for a peak summer load?

A. As shown on Exhibit No.___ (DJN-1), Montana-Dakota's peak summer load indicated by the red line typically tracks with customer energy requirements indicated by the blue line. Based on 2012 peak data and weather and if similar weather conditions would have been

1 experienced in 2014 it is likely that Montana-Dakota would have seen a
2 peak summer load of approximately 650 MW.

3 **Q. What would Montana-Dakota's summer peak load in 2014 have been**
4 **if the summer peak load would have occurred on an adjusted 50/50**
5 **peak summer load condition?**

6 Montana-Dakota's last peak demand versus temperature study
7 indicated that for every one additional degree Fahrenheit of temperature
8 increase on peak during the summer, customer load would increase by 6
9 MWs.[1] Montana-Dakota's weighted average system temperature during
10 the summer peak of 2014 was 88 degrees Fahrenheit compared to a
11 weighted average 50/50 system peak temperature of 96.5 degrees
12 Fahrenheit.[2] The adjusted 50/50 peak summer load for 2014 would equate
13 to 584 MW (533 MW + 51 MW) as compared to an actual peak winter load
14 in 2014 of 557 MW.

15 **Q. What capacity and energy resources has Montana-Dakota added to**
16 **meet its customer requirements since 1985?**

17 A. Montana-Dakota has added the following capacity and energy
18 generation resources since 1985:

19 1986 66 MW AVS II Capacity and Energy Purchase Agreement
20 2003 43 MW Glendive Unit II Natural Gas Combustion Turbine
21 2006 Expiration of 66 MW AVS II Capacity and Energy Purchase Agreement
22 2007 19.5 MW Diamond Willow I Wind Project
23 2009 7.5 MW Glen Ullin Heat Recovery Project

[1] 2015-2034 Montana-Dakota Long-Term Load Forecast. Page 31.
[2] 2015-2034 Montana-Dakota Long-Term Load Forecast. Page 32.

2010	19.5 MW Cedar Hills Wind Project
	10.5 MW Diamond Willow II Wind Project
2012	110 MW We Energies Annual Capacity Purchase Agreement
2013	115 MW We Energies Annual Capacity Purchase Agreement
2014	120 MW We Energies Annual Capacity Purchase Agreement
2014	88 MW Heskett III Natural Gas Combustion Turbine
2015	107.5 MW Thunder Spirit Wind Project (12/31/15)
	19 MW Reciprocating Engine Project (12/31/15

Q. How much capacity credit does Montana-Dakota receive from MISO for its renewable wind resources to meet it customer's peak demand obligations and what will the total accredited capacity be as of year-end 2015?

A. On average, Montana-Dakota receives approximately 20 percent of nameplate capacity credit for its renewable wind resources from MISO to meet its customer's peak demand obligations. Montana-Dakota's total accredited generating capacity will be approximately 550 zonal resource credits (ZRCs) at year end 2015.

Q. Can you please describe Montana-Dakota's Integrated Resources Planning Process?

A. Montana-Dakota is required to file a bi-annual Integrated Resource Plan (IRP) every odd year in Montana and North Dakota. The IRP planning process looks at future load forecasts, supply-side resources and demand response/energy efficiency programs to develop a least cost planning process. This planning process has worked well over the years

1 to address system changes and requirements and inform state regulators
2 about Montana-Dakota's generation expansion plans.
3 **Q. How have the recent IRP planning processes helped to evaluate the**
4 **construction of recent generation additions for the Company?**
5 A. As part of the 2011 IRP process, the Company evaluated the Big
6 Stone Air Quality Control System Project (AQCS) as described by Mr.
7 Skabo and Mr. Welte, to determine if the addition of the pollution control
8 equipment required to continue to operate the Big Stone Station after
9 2017 was economically justified. The need for incremental capacity was
10 also identified in the 2011 IRP wherein the Heskett III generator was
11 determined to be the best cost option for meeting the identified capacity
12 need addition. Both the Big Stone Station AQCS and Heskett III generator
13 were included in the 2011 IRP Two Year Action Plan.
14 As part of the 2013 IRP, the need for up to 73 MW of internal
15 combustion engines was identified in addition to up to 100 MW of wind
16 energy. The 2013 IRP also supported the additions required to continue
17 to operate the Lewis & Clark Station as a coal fired unit and described by
18 Mr. Welte.
19 The 2015 IRP process continues to support the generation retrofits
20 and additions included in this rate case, in addition to a partnership of
21 approximately 200 MW from a large combined cycle natural gas baseload
22 unit in the year 2020.
23 **Q. Please describe Montana-Dakota's Heskett III Project.**

1 A. The Heskett III Project (Heskett III) includes a natural gas-fired, 88
2 MW, simple cycle combustion turbine and the facilities to interconnect with
3 Montana-Dakota's existing electric system. Heskett III is located near
4 Mandan, North Dakota adjacent to Montana-Dakota's R.M. Heskett
5 Station. Heskett III is integrated into the Heskett Station operations
6 utilizing existing plant personal, land, and water and electric infrastructure.
7 Heskett III became operational the summer of 2014. Heskett Station
8 added two new plant employee to its staffing to support the operations &
9 maintenance of Hesket III.

10 **Q. Describe the process whereby Montana-Dakota determined it was in**
11 **the best interest of its customers to construct the Heskett III**
12 **resource.**

13 A. The justification for the Heskett III resource was part of the
14 Company's 2011 Integrated Resource Plan. The need for the Heskett III
15 resource was driven by customer load growth and the expiration date of a
16 three year capacity purchase agreement with We Energies to purchase
17 between 110 MW to 120 MW of annual purchased capacity which was
18 part of the Company's 2009 Integrated Resource plan. This purchased
19 capacity agreement with We Energies expired on May 31, 2015.
20 On June 1, 2010, Montana-Dakota issued a request for proposal
21 (2010 RFP) for all capacity and energy resources beginning on June 1,
22 2015 totaling between 25 and 225 MW. The analysis of bids received as
23 part of the 2010 RFP and supply side resources available to the Company
24 as part of its 2011 Integrated Resource Plan led to the selection of the 88

1 MW Heskett III combustion turbine as the best cost resource for Montana-
2 Dakota and its customers.

3 **Q. If Heskett III was best cost does that mean that other alternatives**
4 **were least cost?**

5 A. As part of its 2010 RFP process, Montana-Dakota received a lower
6 cost alternative from an existing simple cycle combustion turbine project
7 located in Illinois under a 20 year power purchase agreement. For various
8 reasons including location, capacity portability issues, additional
9 transmission service requests, and differences in energy costs to serve
10 Montana-Dakota's customer load, this project was deemed to not be in the
11 best interest of the Company and its customers as a long-term capacity
12 and energy resource.

13 **Q. How will the new 88 MW Heskett III project be used to serve**
14 **customer needs?**

15 A. The 88 MW Heskett III project will be used to serve customer peak
16 demand requirements and reduce the dependency on third party capacity
17 purchases as well as supplying energy when the energy cost of the unit is
18 less than the next marginal cost unit available to the market.

19 **Q. Please describe the Lewis & Clark RICE Project.**

20 The Lewis & Clark RICE project is an 18.6 MW natural-gas fired
21 reciprocating engine project comprised of two 9.3 MW Wartsilla 20V34SG
22 generating units. The Lewis & Clark RICE project will be located on land
23 owned by the Company and adjacent to the Lewis & Clark coal-fired
24 generating system near Sidney, MT. The project is scheduled to be

completed the fall of 2015 with an installed cost of approximately $43 million.

The Lewis & Clark RICE project will interconnect into the existing Lewis & Clark 115kV substation and receive natural gas for the existing WBI Energy pipeline serving the Lewis & Clark Station. With the continued development of new natural gas sources and pipelines in the Bakken Area, Montana-Dakota is able to contract with WBI Energy for firm natural gas transportation at Lewis & Clark Station which was previously unavailable.

The layout for the Lewis & Clark RICE project will be designed for the potential expansion of two additional 9.3 MW Wartsilla 20V34SG generating units in the future. Co-locating the RICE project at the existing Lewis & Clark Station provides many synergies and cost savings with the utilization of existing company property and facilities including land, natural gas pipeline, and electric transmission and substations. Locating next to the existing Lewis & Clark Station also allows the operation of the RICE project with minimal employee additions.

Montana-Dakota has received all necessary permits and approvals for the construction of the project. Corval Group, Inc. has been selected as the contractor for the project and Sargent & Lundy is providing engineering and construction managements services.

Construction of the project began in March of 2015 and the project is expected to be completed in late 2015.

Q. Can you describe the need for the Lewis & Clark RICE Project?

1 A. The need for the Lewis & Clark RICE project was demonstrated as
2 part of the Company's 2013 IRP[3] and the project will be used to meet the
3 Company's growing peak load requirements as well as provide another
4 generating resource in the transmission constrained Bakken Oil Field
5 areas of northeastern Montana and northwestern North Dakota. The
6 construction of the Lewis & Clark RICE improves system reliability and
7 offsets the need to construct more expensive new electric transmission
8 facilities into the Bakken area.
9 Upon the expiration of the 120 MW We Energies capacity purchase
10 agreement on May 31, 2015, and the addition of the 88 MW Heskett III
11 generating resource, Montana-Dakota will have a capacity deficit of 16.6
12 MW for the 2015-2016 MISO Planning Year and in need of additional
13 capacity resources for the future.
14 The Lewis & Clark RICE project will be used as a rapid start
15 generating resource to economically respond to customer energy needs
16 and provide another system support resource if transmission outages and
17 curtailments occur in the transmission constrained areas of eastern
18 Montana and western North Dakota. The past three years the Company
19 has contracted with Basin Electric for seasonal generation redispatch of
20 their resources to mitigate potential curtailment and customer load
21 reduction requests from Western Area Power Administration. Basin
22 Electric has offered this redispatch service on an as available basis with

[3] 2013 Montana-Dakota Utilities Co. Integrated Resource Plan. Attachment C – Supply-Side & Integration Documentation. Page 21.

all Basin Electric owned generation resources servicing Basin Electric member customers first and Montana-Dakota customers if additional generation is available. Basin Electric generally has had excess resources available to fulfill this need but only on a seasonal and as available basis.

Basin Electric is in the process of constructing a new 345kV transmission line from Antelope Valley Station near Beulah, ND to Williston, ND and Tioga, ND (AVS-Nesset). The first phase of the project, AVS to Williston, is scheduled to be completed by the fall of 2015.

Q. What will happen if Basin Electric's AVS to Williston 345kV transmission line is not completed by this fall?

A. If Basin Electric is unable to complete its AVS to Williston 345kV transmission line, the Bakken load serving area may be transmission limited to serve the entire load in the area under peak load system intact conditions.[4] The region will also be transmission limited under more restrictive first contingency conditions. Montana-Dakota generation and demand respond programs will be critical to ensure the Company's ability to serve all of the customer loads in the region. Basin Electric has an aggressive construction schedule to complete the AVS to Williston 345kV transmission line by the fall of 2015.

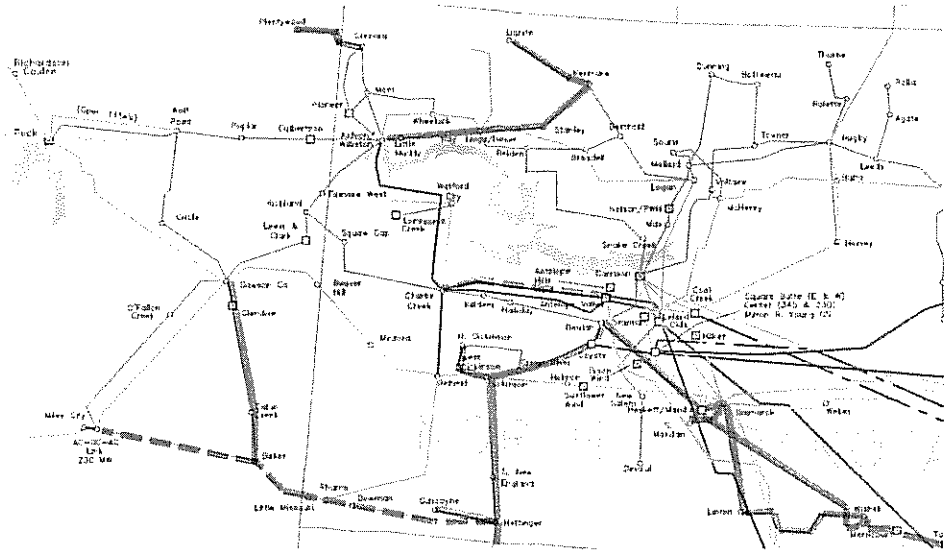
Q. Why doesn't Montana-Dakota build its own transmission instead of depending on WAPA and Basin Electric in the Williston area?

[4] Bakken Update. July 2014. Page 13.
http://www.oasis.oati.com/WAPA/WAPAdocs/Bakken_Update_July_2014.pdf

Montana-Dakota has received less than ten percent of all the new load growth associated with the Bakken Oil Field development with Basin Electric and its members serving the majority of the new load additions.

Montana-Dakota is transmission dependent on WAPA and Basin Electric in the Bakken Region for bulk power delivery facilities. Montana-Dakota currently serves about 150 MW of peak load in the Bakken region while Basin and WAPA serve 700 MW of peak load.

The following map highlights the high-voltage transmission lines (>100kV) that Montana-Dakota owns in Montana and North Dakota. Dashed lines indicate the high-voltage transmission lines that the Company co-owns with WAPA and Basin Electric.



For Montana-Dakota to build its own Midcontinent Independent System Operator (MISO) transmission facilities into the region it would have to construct transmission facilities from Beulah, ND, or Dickinson, ND, into the Williston, ND, area which is cost prohibitive as compared to continuing to take transmission service from WAPA and Basin. New high

voltage transmission generally costs between $1 million to $2 million per mile to construct and a new transmission line from either Beulah or Dickinson to Williston would cost over $100 million and take over three years to complete.

Q. Please describe the Thunder Spirit Wind Project.

A. Thunder Spirit Wind (Thunder Spirit) is a 107.5 megawatt (MW) wind project under construction in Adams County, North Dakota, northeast of the City of Hettinger. Thunder Spirit will be comprised of 43 Nordex N100/2500 (2.5 MW) wind turbines erected on 80 meter towers. Thunder Spirit is expected to be online by the end of 2015. With a capacity factor of 45.2 percent, the average annual output of Thunder Spirit is projected at 426,000 megawatt-hours per year.

Adams County is in southwestern North Dakota in one of the best wind areas in the region based upon actual site wind data and wind assessment studies conducted for Thunder Spirit. Thunder Spirit has received all of its major permits and agreements including a generation interconnection agreement with MISO and a turbine supply agreement with Nordex USA, Inc.

Thunder Spirit will interconnect at the adjacent Montana-Dakota Hettinger 230 kilovolt (kV) Junction Substation. Thunder Spirit has all of the necessary land agreements and interconnection rights to expand the site to accommodate a project with a total size of 150 MW.

Q. How did Montana-Dakota originally select and contract for Thunder Spirit?

A. A comparable sized wind project was selected as a least cost resource in the Company's 2013 Integrated Resources Plan. Following a review of responses to a request for proposal (RFP) for all capacity and energy resources issued on March 25, 2013, Montana-Dakota selected Thunder Spirit over several other potential wind projects offered to the Company. Thunder Spirit was selected as the best opportunity for an energy resource based upon its price, contract terms, and location.

In October 2013, Montana-Dakota entered into a 25 year PPA with Thunder Spirit Wind, LLC (TSW) to purchase the output of 107.5 MW Thunder Spirit at an attractive price. In addition to the attractive price, Montana-Dakota viewed the site as favorable as it could easily be interconnected to the Company's Hettinger 230 kV Junction Substation with few transmission upgrades. On-site measured data and long-term wind assessment studies demonstrated the area has an excellent wind regime. No other wind projects are currently located in the Hettinger area making the likelihood for project output curtailments to be small compared to other project opportunities that Montana-Dakota reviewed in other parts of the state which have higher curtailment risks. Most Power Purchase Agreements (PPA's) require the buyer to take on curtailment risks and include make-whole payments - PPA price plus tax adjusted Federal Production Tax Credits (PTCs) - to the seller. Because of the minimal likelihood of curtailment events, TSW was willing to take on all curtailment risks except for economic and buyer requested curtailments.

1 **Q. Why is the Company now planning to own Thunder Spirit as opposed**
2 **to buying the output through a PPA?**
3 A. The Thunder Spirit project was scheduled to be completed by
4 December 31, 2015, in order to qualify for PTCs. Montana-Dakota's
5 obligations under the PPA were conditioned on TSW obtaining project
6 financing by February 28, 2014. Despite extensions to the financing
7 deadline granted by Montana-Dakota and interest in Thunder Spirit shown
8 by several investors, it became apparent TSW could not obtain financing
9 without price increases and other amendments to the PPA. With the
10 uncertainty of TSW's ability to timely obtain financing, even with increased
11 PPA prices and other concessions requested by TSW, Montana-Dakota
12 determined it was advantageous and in the best interest of its customers
13 to consider owning and operating Thunder Spirit as an alternative to the
14 PPA arrangement.
15 Ownership provides Montana-Dakota with control of the project site
16 and equipment along with the ability to capture additional value from
17 Thunder Spirit after the expiration of a PPA. All of the wind energy
18 purchased under the PPA is at the contract price and if Thunder Spirit
19 generates more energy than the P50 wind forecast (50/50 historic wind
20 potential) the Company still pays the contract price for all of the energy
21 above the P50 output level. Under an ownership scenario, customers
22 receive the benefits of this additional generation at no additional cost.
23 Ownership also provides Montana-Dakota with the ability to expand the

1 site in the future, if needed, to meet its customers' energy requirements
2 while capturing the economies of scale offered by a larger project site.
3 Ownership also provides the ability to manage the uncertainty of
4 inflation and future maintenance costs in the later years of the project. The
5 uncertainty of maintenance and inflation costs in the later years of a wind
6 PPA tends to increase its contracted price to ensure the asset owner will
7 recover sufficient revenue at the end of the contract to cover its costs plus
8 a profit. Ownership allows recovery of actual costs from customers and
9 eliminates the need for uncertainty and additional profit adders.
10 Thunder Spirit is a low cost generation resource opportunity for
11 Montana-Dakota that provides numerous benefits including price
12 protection against future MISO energy prices, price protection against
13 increases in future natural gas prices, greater fuel source diversity in the
14 Company's generation mix, and the ability to capture significant value from
15 federal and state tax incentives.
16 **Q. Would you please describe the current development arrangement for**
17 **the Thunder Spirit Wind Project?**
18 A. In September 2014, Montana-Dakota contacted Allete Clean
19 Energy (ACE), a subsidiary of Allete, Inc., which has developed other wind
20 projects in North Dakota, to determine if ACE would consider acquiring the
21 Thunder Spirit Wind Project, completing its development, and selling the
22 completed Project to Montana-Dakota. ACE reviewed the Thunder Spirit
23 Wind Project and determined that it was willing to develop the Thunder
24 Spirit Wind Project and either sell the output or the completed project to

1 Montana-Dakota. ACE acquired TSW from the developers and
2 contemporaneously TSW and Montana-Dakota entered into both an
3 amended PPA and a conditional asset purchase agreement for Thunder
4 Spirit. Pursuant to the agreements, Montana-Dakota agreed to purchase
5 Thunder Spirit after completion and prior to its commercial operations date
6 conditioned upon approval by the North Dakota Public Service
7 Commission of a Certificate of Public Convenience and Necessity and an
8 Advance Determination of Prudence for the purchase in North Dakota.
9 Alternatively, Montana-Dakota agreed to purchase the Thunder Spirit
10 output under the terms of the amended PPA if Montana-Dakota's
11 applications for a Certificate of Public Convenience and Necessity and
12 Advance Determination of Prudence with the North Dakota Public Service
13 Commission were not approved. Both the asset purchase agreement and
14 the amended and PPA were signed on November 20, 2014. This
15 arrangement allows Montana-Dakota to eventually own the project,
16 without having to add additional staff to manage the design and
17 construction of the project.
18 **Q. How will Montana-Dakota utilize Thunder Spirit to meet customer**
19 **needs?**
20 A. Thunder Spirit will help keep energy prices to Montana-Dakota's
21 customers as low as possible. Since the expiration of the 66 MW
22 Antelope Valley Station Unit II PPA with Basin Electric in 2006, Montana-
23 Dakota has been a net purchaser of energy from others to meet its
24 customers' energy requirements. The Company's most recent long-term

1 forecast indicates customer energy requirements will be increasing by 4.6
2 percent per year for the next five years.[5] The amount of energy that
3 Montana-Dakota purchases from the MISO energy market has grown from
4 10 percent, or 308,000 MWhs, in 2007 to over 20 percent, or 906,516
5 MWhs, in 2014 despite the addition of generation resources during the
6 same time period. Without the addition of a new energy supply resource
7 like Thunder Spirit, this number is forecasted to increase to almost 40
8 percent by 2016 based upon Plexos generation and market dispatch
9 simulation runs. Even with Thunder Spirit, Montana-Dakota's energy
10 purchases from MISO are still expected to be almost 20 percent of its
11 customers' annual energy requirements in 2016.

12 **Q. How will Thunder Spirit qualify for the Federal Production Tax**
13 **Credits (PTC)?**

14 A. When Montana-Dakota negotiated the Purchase and Sale
15 agreement for Thunder Spirit, qualification for PTCs required that
16 construction of the project have commenced prior to December 31, 2013
17 and that "continuous efforts" be made toward its completion. Under
18 Internal Revenue Service guidelines, the first part of this test could be met
19 by the project incurring five percent of the project costs prior to December
20 31, 2013. Thunder Spirit met this part of the test by the acquisition of
21 certain turbine parts and other preliminary project work during 2013. IRS
22 guidelines provided the second part of the test is deemed to have been
23 met if the project is completed by a 'safe harbor' date of December 31,

[5] 2015-2034 Montana-Dakota Long-Term Load Forecast. Page 27.

2015. If the project is completed after December 31, 2015, the taxpayer must be prepared to show by "facts and circumstances" that continuous efforts were made in 2014 and 2015 to complete the project.

To provide for delivery of the wind turbine equipment in the summer and fall of 2015 to meet a December 31, 2015, completion date, TSW issued a notice to proceed and made a sizeable down payment to the turbine supplier on November 20, 2014. The delivery schedule for the turbine equipment allows for erection and commissioning of the turbines to meet the December 31, 2015, safe harbor completion date.

On December 19, 2014, the deadlines by which construction of a facility must begin to qualify for PTC's, were extended by one year under the Tax Increase Prevention Act of 2014, Pub. L. No. 113-295, 128 Stat. 4010. On March 11, 2015, the IRS released an advanced version of Notice 2015-25 updating prior guidance to incorporate the enactment of the "tax extender" legislation. In particular, the Notice extends by one year the date by which a facility must be placed in service to satisfy the Continuous Efforts Test. Accordingly, if the facility is placed into service before January 1, 2017, the facility will be considered to satisfy the safe harbor of the Continuous Efforts Test. The Notice also states the IRS will not issue private letter rulings regarding application of the Notice. With the enactment of the Tax Increase Prevention Act of 2014 and the guidance provided by IRS Notice 2015-25, Montana-Dakota does not believe there is any meaningful risk that Thunder Spirit will not qualify for PTCs.

1 **Q. What is the status of the major Thunder Spirit contracts and**
2 **agreements?**
3 A. TSW, in its efforts as developer, completed the necessary project
4 studies and agreements to develop a wind project capable of achieving
5 commercial operation by December 31, 2015. The turbine supply
6 agreement with Nordex includes a five year turbine operation and
7 maintenance agreement with a five year extension option available at the
8 buyer's request.
9 TSW signed a large generator interconnection agreement with
10 MISO and Montana-Dakota for a 150 MW interconnection into Montana-
11 Dakota's Hettinger 230 kV Junction Substation located near Hettinger,
12 North Dakota. The network upgrades under this interconnection
13 agreement are expected to be less than $1.5 million and include the
14 addition of a 230 kV breaker bay, isolation switches, and necessary
15 protective relaying, which will be paid by TSW and are included in the
16 asset purchase price to Montana-Dakota. As part of a MISO transmission
17 service request for firm point-to-point transmission service under the PPA,
18 Montana-Dakota also needs to reconductor the five miles of Montana-
19 Dakota's 115kV line between the Coyote and Beulah Junction Substations
20 to increase its facility rating to accommodate the transmission service
21 request. The cost of this reconductoring, as well as the cost of some other
22 minor transmission upgrades that Montana-Dakota will incur, are
23 estimated to be less than $1 million.

TSW has obtained all of the necessary local and state siting permits for the 150 MW project site. It has the necessary FAA determinations along with the necessary fish and wildlife and cultural resource study results. TSW has secured wind energy leases and easements to support a 150 MW project through lease and easement agreements with over 40 landowners.

TSW contracted with Wanzek Construction (Wanzek) to perform the engineering, procurement, and construction activities. Wanzek completed the necessary engineering for the project during the winter of 2014-2015 along with procurement of long lead-time equipment for timely delivery in the summer of 2015. Wanzek will also be responsible for the construction of the substation and 230kV interconnection line, less than one mile in length, between the Thunder Spirit substation and Montana-Dakota's Hettinger 230kV Junction Substation and began mobilizing its construction crews to the site at the end of April 2015 with the start of roads and civil construction. Finally, Wanzek will be responsible for the turbine erection and Nordex will provide for the turbine commissioning.

Q. What is the Thunder Spirit construction schedule for 2015?

A. Nordex began delivery of equipment to the site with foundation inserts in May and padmount transformers in June. Turbine equipment is scheduled to begin arriving on-site in July and be completed the end of September. Work on the electrical interconnection will start in June and be complete by the end of September. Turbine commissioning will begin in September and continue through the end of November, assuming no

1 delays or issues with the construction schedule or equipment deliveries
2 occur.
3 **Q. Who has ownership of the renewable energy and capacity credits**
4 **generated by Thunder Spirit?**
5 A. Montana-Dakota will have ownership of the renewable energy
6 credits (RECs) and capacity credits whether it owns Thunder Spirit or
7 purchases the output under a PPA arrangement. Currently seven percent
8 of Montana-Dakota's customer energy requirements come from renewable
9 generation including Diamond Willow I and II, Cedar Hills, and the Glen
10 Ullin heat recovery generator. With the addition of Thunder Spirit, 20
11 percent of Montana-Dakota's 2016 customer energy requirements will
12 come from cost effective renewable generation.
13 **Q. How will the Thunder Spirit project help the Company meet the**
14 **Montana Renewable Portfolio Standard (RPS) requirements?**
15 The Montana RPS requires ten percent of the electricity to serve
16 Montana customers to come from qualified renewable sources beginning
17 in 2010 and increases to 15 percent in 2015. Montana's share of
18 renewable energy credits (RECs) generated from Cedar Hills and
19 Diamond Willow I and II are retired to meet Montana-Dakota's obligations
20 under the Montana RPS. Montana's share of RECs from Cedar Hills,
21 Diamond Willow I and II are not enough to meet the Montana RPS
22 requirement and Montana-Dakota purchases RECs from North Dakota
23 and South Dakota's share of Cedar Hills and Diamond Willow I and II, at
24 current market prices, to meet the Montana RPS. In as early as 2018,

RECs from Cedar Hills, Diamond Willow I and II will not be enough to meet the 15 percent Montana RPS requirement and Montana-Dakota would be required to purchase RECs from third parties without the Thunder Spirit project. With the addition of Thunder Spirit Wind in 2016, 20 percent of energy requirements to serve Montana-Dakota customers will come from renewable resources.

Q. Please describe the asset purchase arrangement Montana-Dakota has with ACE Wind LLC.

A. Under the Asset Purchase Agreement with ACE Wind LLC, Allete Clean Energy will construct Thunder Spirit and sell to Montana-Dakota, prior to commercial operation, a complete project capable of fulfilling the requirements of the Amended and Restated Power Purchase Agreement between the Parties.

The total investment for the Thunder Spirit Wind Project is $220 million which includes the project purchase from ACE Wind LLC along with project financing and Montana-Dakota's owner costs.

In the event an Advance Determination of Prudence and Certificate of Public Convenience and Necessity are not approved for the purchase of the Project in North Dakota, Allete will remain the owner and sell the output to Montana-Dakota under a 20 or 25 year PPA.

Q. Who will provide the turbine and balance of plant operations and maintenance for Thunder Spirit?

A. As previously stated, Nordex will provide, under a maintenance service arrangement (MSA), for the initial operation and maintenance

(O&M) of the project wind turbines excluding major complements like turbine blades, generators, gearboxes, bedplates, and tower sections at an initial cost of $1.8 million per year. The turbine supply agreement provides for two years of equipment warranty coverage after which Montana-Dakota will need to supply spare parts. Nordex will continue to supply consumables, excluding gearbox oil changes, under the MSA. Following the initial five years of the MSA, Montana-Dakota has the option to contract with Nordex for an additional five years of O&M under similar terms and conditions as the initial five year term including future negotiated price adjustments.

Montana-Dakota will be responsible for the O&M of Thunder Spirit's balance of plant equipment which includes all equipment from the turbine padmount transformers through the collector system and back to the point of interconnection at Montana-Dakota's Hettinger 230kV Junction Substation. Montana-Dakota will be responsible for all requirements under the wind lease and easement agreements with local landowners at an annual cost of $500,000 per year. Montana-Dakota will be responsible for all agreements and permits including the interconnection agreement with MISO. Montana-Dakota anticipates hiring two new employees for the balance of plant O&M activities.

Q. **Can you describe the economic modeling that went into the decision to purchase Thunder Spirit?**

Montana-Dakota conducted additional modeling runs using the 2013 IRP EGEAS model as part of its evaluation process. The additional

model runs included a 107.5 MW PPA at the purchase price contained in the amended and restated power purchase agreement with ACE along with a twenty percent capacity credit that could be used to meet Montana-Dakota's MISO resource adequacy requirements. The purchase option used a financial model to develop the revenue requirement cost to Montana-Dakota based upon: (a) the terms of the asset purchase agreement, (b) the Nordex maintenance supply agreement, and (c) the applicability of the current Federal PTC for new wind generation as PTCs will reduce Thunder Spirit's total cost by approximately 40 percent over its life. The revenue requirement for the purchase option was then entered into the 2013 IRP EGEAS model as a future resource alternative.

Both the amended and restated PPA and the purchase option were selected as least cost alternatives for Montana-Dakota's customers with the purchase option resulting in a lower net present value revenue requirement of approximately $30 million over the PPA option over the 20 year expected life of the wind project. Exhibit No.___(DJN-2), provides a summary of the Net Present Value of the revenue requirement for all resources under the Optimal Resource Case originally submitted in the 2013 IRP and the Net Present Value of the Revenue Requirement under: 1) Optimal Resource Plans assuming the energy produced by the Project is purchased under a PPA and 2) Montana-Dakota owns and operates Thunder Spirit. As shown, the ownership option provides the least cost plan and does not affect the other future resources identified in the 2013 IRP. An additional scenario 3) is also included whereby the wind PPA and

1 purchase option were removed from the 2013 IRP Optimal Resource
2 Case which resulted in an increase in the NPV revenue requirement of
3 over $100 million as compared to the purchase option.
4 The levelized cost of the overall Project over a twenty year period is
5 $31.96 per MWh under the purchase arrangement.
6 **Q. Did the Company review the acquisition price of the Thunder Spirit**
7 **Wind Project as part of the development of its 2015 Integrated**
8 **Resource Plan?**
9 A. Yes, as part of the 2015 Integrated Resource Plan (2015 IRP),
10 Montana-Dakota considered the Thunder Spirit project as a new supply
11 side available for selection under the least cost plan. The final 2015 IRP
12 report selects the Thunder Spirit Wind project as a least cost resource
13 under all scenarios.
14 Montana-Dakota also utilized a preliminary 2015 IRP model to see
15 if the Thunder Spirit Wind project would be considered a least cost
16 resource over other alternatives, including the Amended and Restated
17 PPA and no wind addition scenarios. The following table summarizes the
18 results of these addition studies.
19

2015 Preliminary Base Case (PBC) includes owning Thunder Spirit

2015	10 MW Purchase Power
	Big Stone AQCS Project
2016	107.5 MW Thunder Spirit Owned
	Lewis & Clark MATS Project
	Lewis & Clark Reciprocating Engines
2017	37.3 MW of combustion turbine

2018		
2019	10 MW Purchase Power	
	20MW self-built wind	
2020	200 MW of Combined Cycle	
	NPV	$4,589 million

*Resources in **bold** are committed in the model. The NPV from the 2015 PBC differs from the 2015 IRP Base Case due to updates in forecasted natural gas forecast prices between the models.

1

1) 2015 PBC with 107.5 MW Amended and Restated TSW PPA Pricing

2015	10 MW Purchase Power	
	Big Stone AQCS Project	
2016	107.5 MW Thunder Spirit PPA	
	Lewis & Clark MATS Project	
	Lewis & Clark Reciprocating Engines	
2017	37.3 MW of combustion turbine	
2018		
2019	10 MW Purchase Power	
	20MW self-built wind	
2020	200 MW of Combined Cycle	
	NPV	$4,610 million

2

2) 2015 PBC with no new wind

2015	10 MW Purchase Power	
	Big Stone AQCS Project	
2016	20 MW Purchase Power	
	Lewis & Clark MATS Project	
	Lewis & Clark Reciprocating Engines	
2017	37.3 MW of combustion turbine	
2018	28 MW of reciprocating engines	
2019	10 MW Purchase Power	
2020	200 MW of Combined Cycle	
	NPV	$4,712 million

3

1 The following table outlines the difference in the annual revenue
2 requirements from the preliminary 2015 IRP model between the 1) Own
3 Thunder Spirit Wind option versus the 2) No Wind option.

Annual Revenue Requirement (In Millions of Dollars)			
	1) Own TSW	2) No wind	Option 1) less 2)
2016	$165.34	$159.46	$5.88
2017	164.49	167.38	(2.89)
2018	167.36	174.53	(7.17)
2019	176.80	182.69	(5.90)
2020	201.84	210.15	(8.32)
2021	205.37	215.70	(10.33)
2022	211.63	223.54	(11.91)
2023	218.38	231.81	(13.43)
2024	225.32	240.04	(14.72)
2025	234.72	251.46	(16.74)

4 **Q. What approvals and conditions are required under the Asset**
5 **Purchase Agreement with TSW and ACE Wind LLC?**
6 A. The only approvals needed by Montana-Dakota under the Asset
7 Purchase Agreement with TSW and ACE Wind LLC are the North Dakota
8 Public Service Commission Advance Determination of Prudence,
9 Certificate of Public Convenience and Necessity and FERC approval of
10 the ownership transfer under Section 203 of the Federal Power Act.
11 **Q. Why doesn't Montana-Dakota rely entirely on the market to supply**
12 **future capacity and energy resources?**
13 A. Market prices fluctuate up and down but over time and the general
14 trend is that market prices increase with inflation and changes in supply
15 and demand. In 2015, without the addition of Heskett III, Montana-Dakota

1 would be purchasing 25 percent of its capacity resources from others to
2 serve peak customer demand requirements.
3 The value of direct purchased capacity is tied to an actual
4 resources cost, which includes its net book value and fixed operations and
5 maintenance costs. For markets, the value of capacity is tied to
6 competition in supply resources and the cost of new entry (CONE)
7 resources. MISO annually calculates the value of CONE, which is the
8 revenue requirement of a new simple cycle combustion turbine, and
9 establishes a penalty to those entities that are short capacity resource
10 requirements based on the current value of CONE. As the amount of
11 excess capacity in the current market decreases, either through load
12 growth or unit retirements, the market value of capacity will approach the
13 value of CONE. The cost of new entry resources or CONE increases over
14 time with inflation and new equipment costs. Long-term price stability is
15 maintained either through ownership of new resources or entry into long-
16 term capacity purchase agreements.
17 Q. **Why doesn't Montana-Dakota consider the MISO capacity market as**
18 **a long-term option for meeting its resource adequacy requirements?**
19 Market purchases may be appealing in the short-term but over time
20 they will correct themselves with changes in supply and demand or market
21 rules. Prior to Heskett III, Montana-Dakota had not added a large capacity
22 resource to its generation portfolio since the Glendive Unit II combustion
23 turbine was built in 2003. A power purchase agreement with Basin Electric
24 Power Cooperative for 66 MW of baseload capacity from the Antelope

1 Valley Station Unit II expired in November 2006, which left Montana-
2 Dakota dependent on capacity purchase agreements and market energy
3 prices. Montana-Dakota was unable to acquire additional coal-fired
4 baseload resources when the Big Stone II project was abandoned.
5 Montana-Dakota has used the MISO capacity auction for short-term
6 capacity needs where its makes economic sense to do so as evidence by
7 the recent purchase of 16.6 MW of capacity from the MISO capacity
8 market for the 2015-2016 MISO planning year.
9 Continued reliance on market purchases subjects customers to
10 unknown future prices of capacity and energy. At the expiration of
11 purchased power agreements, there are no remaining assets for
12 continued customer benefit and customers are subjected to the cost
13 impacts of replacement agreements with future market resources.
14 **Q. Can you describe the development of the organized MISO Energy**
15 **Market including Montana-Dakota participation?**
16 A. The Midcontinent Independent System Operator (MISO) originally
17 formed as a regional transmission organization in 2002 for the operation,
18 planning, and sharing of transmission facilities under a common open
19 access tariff. Montana-Dakota was one of the original transmission owning
20 members of MISO.
21 The MISO energy market began operation in 2005 and the ancillary
22 service portion of the MISO energy market started in 2009.
23 As a MISO market participant, Montana-Dakota forecasts its day
24 ahead load and submits its load forecast into the day ahead market each

1 morning. Montana-Dakota also submits its day ahead generation pricing
2 offers and available output levels to the market each morning. MISO, on a
3 day ahead basis, balances and awards all load requirements and
4 generation outputs on a most economic and reliable basis through an
5 economic constrained dispatch. Actual differences in day ahead loads and
6 generation awards to real-time loads and generation output is settled in
7 the real-time market and at real-time pricing.
8 The development of the MISO energy market has provided many
9 benefits to Montana-Dakota and its customers. The MISO energy market
10 has greatly reduced the market price fluctuations that Montana-Dakota
11 historically experienced during peak load conditions and during generation
12 outages.
13 **Q. Can you describe Montana-Dakota's future demand-side and supply-**
14 **side energy resource plans?**
15 A. The following is the summary of the Company's two year action
16 plan for demand and supply side resources from its 2015 Integrated
17 Resource Plan[6]:
18 Demand-Side Resources
19 • Montana-Dakota expects to continue to expand the number of
20 interruptible rate customers to achieve a total of 16 MW by 2017.
21 • Montana-Dakota expects to achieve 15 MW of commercial demand
22 response by the summer of 2017.

[6] Montana-Dakota Utilities Co. 2015 Integrated Resource Planning dated July 1, 2015. Main Report. Chapter 7 - Two Year Action Plan.

- Montana-Dakota expects to implement a residential AC Cycling program by 2017 to achieve a total of 10 MW in the program by 2021.

Supply-Side Activities

- Montana-Dakota will continue with the installation of the Big Stone AQCS project to be online by the end of 2015.
- Montana-Dakota will continue with its purchase of the 107.5 MW Thunder Spirit Wind project to be online by the end of 2015.
- Montana-Dakota will continue with the installation of the Lewis & Clark MATS project to be online by the end of 2015.
- Montana-Dakota will continue with the installation of the 18.6 MW Lewis & Clark II simple-cycle reciprocating internal combustion engine project to be online the fall of 2015.
- Montana-Dakota will continue to study the need to install local generation projects throughout its service area to support load growth and mitigate transmission constraints.
- Montana-Dakota will explore the opportunity of partnering with others on the design and construction of a large combined cycle combustion turbine facility with an in-service date in or after 2020 with a 200 MW commitment from Montana-Dakota.
- Montana-Dakota will continue to monitor the availability and price of energy and short-term capacity in the MISO market or through bi-lateral arrangements and will purchase additional capacity as needed to meet customer demand when economic to do so.

- Montana-Dakota will continue to monitor the development of final rules and implementation strategies for EPA 111d greenhouse gas emitting or CPP rules for existing sources, and influence the outcomes where possible.

Q. What is the status of the Western Area Power Administration Transmission Service Agreement?

A. Montana-Dakota's electric service customers in the Interconnected System will see increased transmission service charges with the termination of the Company's reciprocal usage Transmission Services Agreement (TSA) with Western Area Power Administration (WAPA) on December 31, 2015, along with the announcement that WAPA and Basin Electric Power Cooperative (Basin Electric) will be joining Southwest Power Pool (SPP) as a transmission owning member on October 1, 2015.

Q. Can you describe the history of the WAPA TSA?

A. Montana-Dakota and WAPA have a long history of sharing transmission facilities and providing service across each other's systems using a reciprocal wheeling arrangement. This agreement has provided cost savings for Montana-Dakota's customers. The current WAPA TSA will expire on December 31, 2015. Montana-Dakota has attempted to enter into negotiations with WAPA to extend the TSA, but WAPA has indicated that it is unable to extend the TSA.

WAPA and Basin Electric have announced their intention to join SPP as a transmission owning member on October 1, 2015, and as such, transmission service across their facilities will be covered under the SPP

Tariff. With the expiration of the WAPA TSA, Montana-Dakota will be required to take Network Integrated Transmission Service (NITS) under the SPP Tariff for service that it currently receives under the WAPA TSA.

Q. Where will Montana-Dakota be required to take transmission service from SPP following the expiration of the WAPA TSA?

A. It is anticipated that with the termination of the WAPA TSA, all Montana-Dakota transmission service received under the WAPA TSA will now be subject to the SPP Tariff if Montana-Dakota is unable to provide an adequate transmission without support from the SPP transmission system. The area whereby Montana-Dakota is needing to take transmission service from SPP is basically all customer loads west of Beulah, ND, and west of Glenham, SD, as Montana-Dakota only has a single 115kV transmission path west of Beulah to provide a transmission path to the rest of Montana-Dakota's interconnected service territory and the broader MISO transmission system.

Montana-Dakota will keep all of its customer load and generation in the MISO energy market and take transmission service from SPP where it does not have sufficient transmission facilities to serve its customer loads itself.

Q. Why doesn't Montana-Dakota exit MISO and join SPP?

A. Montana-Dakota continues to see greater value in remaining a MISO transmission owning member as compared to the exit MISO and join SPP scenario. The greater MISO value is largely related to a difference in resource adequacy requirements between MISO and SPP.

SPP requires each load serving entity to carry capacity resources for their full forecasted customer load plus a planning reserve margin while MISO includes a diversity factor as not all MISO customer load peaks at the same time and MISO load serving entities are only required to demonstrate their peak load requirements coincident to MISO's annual summer system peak. Montana-Dakota receives a significant benefit from being the western most transmission owning member in MISO, as Montana-Dakota only needs to currently supply 80.3% of their full capacity requirements plus planning reserve margin. If Montana-Dakota were to join SPP, Montana-Dakota would have to add 130 MW of additional capacity resources to its generation supply mix to meet the resource adequacy requirements under the SPP Tariff which equates to incremental required investments of at least $114 million for another Heskett III like resource based upon 2015 IRP pricing.

Q. **What is the cost impact to Montana-Dakota's customers of taking transmission tariff service from both SPP and MISO for the same load?**

A. Based on Montana-Dakota's average customer load in 2014, Montana-Dakota would have been required to secure approximately 325 MW of NITS service from the IS Tariff at $2.96 per kW-month or approximately $11,544,000 per year. The UMZ (WAPA/ Basin Electric load zone) rate under SPP Tariff is still unknown and Montana-Dakota is estimating the rate to be close to $4.00 per kW-month ($15,600,000 per

1 year) with the inclusion of SPP's regional highway / byway cost allocation
2 included.
3 Montana-Dakota is working with SPP, WAPA, and Basin Electric to
4 minimize the SPP transmission bill to its customers via the receipt of
5 Section 30.9 Facility Credits under the SPP Tariff. Facility credits are
6 available under the SPP and MISO tariffs for non-transmission owners
7 whose facilities are integrated into the operation of the respective tariff
8 service area and provide benefits similar to a transmission owner under
9 the tariff. Montana-Dakota would have sought facility credits under the
10 WAPA-IS Tariff if WAPA and Basin Electric would not have elected to join
11 SPP. Montana-Dakota is currently in FERC settlement negotiations with
12 SPP, WAPA, and Basin Electric on the requirements for receipt of SPP
13 Section 30.9 Facility credits which Montana-Dakota hopes will offset a
14 significant portion of its SPP transmission bill.
15 Even with the facility credit offsets, Montana-Dakota is still
16 estimating an increased transmission service charge of $4.0 million at the
17 expiration of the WAPA TSA over the current WAPA and Basin Electric
18 transmission charges that Montana-Dakota is assessed today. In the 2013
19 Montana IRP, Montana-Dakota estimated the cost impact of the expiration
20 of the WAPA TSA on Montana-Dakota customers to be as high as $6.7
21 million per year without offsets.[7]

[7] 2013 Montana-Dakota Utilities Co. Integrated Resource Plan. Volume IV. Attachment J – Future Transmission Service Charge Impacts. Page 1.

1 **Q. How will Montana-Dakota provide energy service to its customers if**
2 **it is taking transmission service from both MISO and SPP?**
3 A. All of Montana-Dakota's load and generation will remain in the
4 MISO energy market. That way, all Montana-Dakota load continues to
5 receive the benefits of MISO's resource adequacy requirements versus
6 SPP's resource adequacy requirements. Although, Montana-Dakota will
7 be subject to a pancake of transmission services charges under the MISO
8 and SPP Tariffs related to taking transmission service from both RTOs for
9 the same load the benefit of having all load remain in the MISO energy
10 market outweighs the pancaked transmission service charges that will be
11 mitigated by facility credits.
12 Q. **What happens if SPP changes its resource adequacy requirements in**
13 **the future to be similar to MISO's resource adequacy requirements?**
14 A. SPP has started the process to review diversification benefits
15 across its footprint as not all customer loads peak at the same time, but
16 SPP has not announced or approved any changes yet to its resource
17 adequacy requirements. Any changes to SPP's resource adequacy
18 requirements is probably at least two years away.
19 If SPP would change its resource adequacy requirements and
20 Montana-Dakota sees similar benefits as MISO, Montana-Dakota would
21 reevaluate its position of remaining a MISO transmission owning member
22 and compare it against the cost of withdrawing from MISO and joining
23 SPP.

1 **Q. What other MISO transmission charges are Montana-Dakota's**
2 **customers subject to regarding cost sharing from others?**
3 A. The MISO RECB I (Regional Expansion Criteria and Benefits) cost
4 allocations allow for the cost sharing of approved network transmission
5 facilities with the benefiting transmission owners or with the entire MISO
6 footprint.
7 Contained in MISO's Federal Energy Regulatory Commission
8 (FERC) Order 1000 compliance filing was the removal to cost share future
9 MISO RECB I projects, also referred to as baseline reliability projects,
10 from the MISO Tariff beginning with the MISO Transmission Expansion
11 Plan (MTEP) 2014. Previously approved MISO RECB I projects will
12 continue to be cost shared as before.
13 As previously approved MISO RECB I and II projects are
14 completed, Montana-Dakota's customers will see an increase in MISO
15 Schedule 26 charges. Schedule 26 allocations are directly assigned
16 revenue requirements for approved MTEP projects to an individual
17 Transmission Owner or all MISO load through a system-wide postage-
18 stamp rate. The CapX2020 Alexandria to Fargo 345 kV transmission line
19 was approved in 2008 as a baseline reliability project eligible for cost
20 sharing under the MISO Tariff. The Alexandria to Fargo 345kV
21 transmission line was placed into service in April 2, 2015. As defined in
22 RECB I, eighty percent (80%) of the revenue requirements for this project
23 are allocated under a line outage distribution factor (LODF) calculation to
24 determine beneficiaries, and the remaining twenty percent (20%) are

allocated to all MISO load through a post-stamp rate. Montana-Dakota's allocated investment share of the Alexandria to Fargo 345 kV line is expected to be around $6.6 million.

Annual revenue requirements for all RECB I projects allocated to Montana-Dakota's transmission pricing zone in MISO are forecasted to equal $3,101,419 dollars in 2016 which includes the cost of the Mandan 230 kV Junction Substation.[8]

Q. How are MISO Multi-Value Projects cost allocated?

A. On December 17, 2010, the FERC approved a joint application filing by the MISO and various MISO Transmission Owners to create a new cost allocation methodology for qualifying multi-value high-voltage transmission facilities called Multi-Value Projects (MVPs). MVPs are one or more network transmission upgrades that, when considered as part of a portfolio, provide widespread regional benefits, respond to documented public policy requirements, and/or provide multiple benefits such as reliability and economic value. Network transmission projects classified as MVPs will be cost-shared on a one hundred percent (100%) basis to all MISO load.

MTEP 2011 approved $5.6 billion for 17 Multi-Value Projects that were selected as part of a regional portfolio to improve reliability of the transmission system, meet public policy targets, and distribute economic

[8] MISO Indicative Annual charges for approved Baseline Reliability Projects (Schedule 26). https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

benefits across the entire MISO footprint.[9] The MTEP 2011 Report identified potential benefits of at least 1.6 to 2.8 times their cost for all MISO Local Resource Zones. The MTEP 2014 MVP Triennial Review Report calculates potential benefits from the 2011 MVP Portfolio of at least 2.3 to 2.8 times their cost for all MISO Local Resource Zones.[10]

One of the 2011 MVP Portfolio projects is a 345 kV transmission line from Big Stone, SD, to Ellendale, ND. Montana-Dakota is developing this project in partnership with Otter Tail Power Company and it is expected to have an in-service date of 2019 with a constructed cost of $396 million[11].

The 2019 forecasted MISO Schedule 26-A (MVP Cost Adder) charge is $1.60 per MWh.[12] Assuming a 2019 Total Energy Requirements of 4,366,313 MWh, this would result in a total charge of $6,986,100 to Montana-Dakota's customers.

Montana-Dakota's cost allocation share of all MVP investments is approximately one percent.

Q. What happens to Montana-Dakota's responsibility to pay for RECB and MVP costs allocations if Montana-Dakota decided to ultimately withdraw from MISO?

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[9] MISO Transmission Expansion Plan 2011. https://www.midwestiso.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf

[10] MISO 2014 MVP Triennial Review Report. https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MTEP14%20MVP%20Triennial%20Review%20Report.pdf. Page 8. Figure E-3.

[11] MISO 2014 MVP Triennial Review Report. https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MTEP14%20MVP%20Triennial%20Review%20Report.pdf. Page 20. Figure 4-1.

[12] MISO Indicative Annual charges for approved Multi-Value Projects (Schedule 26-A). https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

1 A. If Montana-Dakota were to withdraw from MISO it would continue to
2 be obligated to pay for all MTEP Appendix A cost shared projects
3 approved for construction prior to its withdraw. This would include all of
4 the Schedule 26 and 26A cost allocated projects discussed already in my
5 testimony or approximately $7 million per year.
6 **Q. Does this conclude your direct testimony?**
7 A. Yes, it does.

Montana-Dakota Utilities Co. Peak Customer Load and Annual Energy Requirements
1985-2014

	Annual Energy Requirements (MWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
1985	1,834,294	350	331
1986	1,751,503	338	324
1987	1,716,377	359	293
1988	1,834,232	387	306
1989	1,828,665	384	321
1990	1,788,854	382	342
1991	1,836,243	387	330
1992	1,827,866	339	312
1993	1,870,268	350	334
1994	1,934,561	370	323
1995	1,952,872	413	349
1996	2,014,830	393	343
1997	2,005,195	405	333
1998	2,007,534	403	354
1999	1,996,647	421	342
2000	2,077,579	432	354
2001	2,104,119	453	329
2002	2,158,431	459	344
2003	2,226,531	471	368
2004	2,204,012	458	384
2005	2,327,117	459	387
2006	2,397,793	486	397
2007	2,510,540	526	407
2008	2,596,990	477	455
2009	2,593,368	474	460
2010	2,718,192	503	458
2011	2,776,082	536	511
2012	2,919,752	574	516
2013	3,115,064	547	582
2014	3,250,683	533	557

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
NET PRESENT VALUE COMPARISONS OF THE REVENUE REQUIREMENTS OF MODEL RUNS

Original 2013 Optimal Resource Case (ORC)

2015	L&C MATS Project
	50 MW of Wind PPA (maximum available to EGEAS model)
	73 MW of Recipricating Engines
2016	
2017	36 MW of Recipricating Engines
2018	
2019	
2020	200 MW of Combined Cycle
	NPV $3,525 million

1) 2013 ORC with 107.5 MW Amended and Restated PPA Pricing

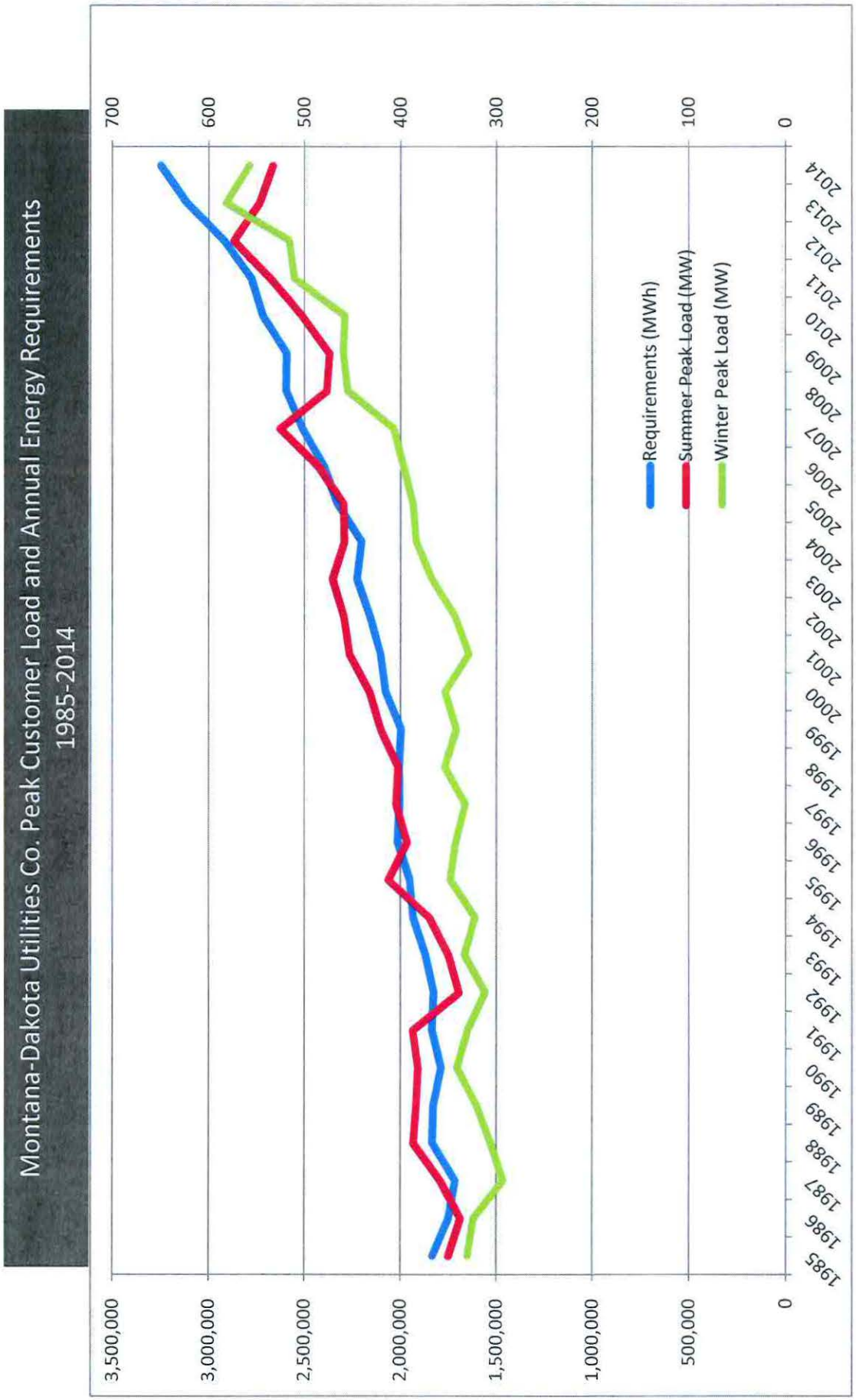
2015	L&C MATS Project
	73 MW of Recipricating Engines
2016	107.5 MW of Wind PPA
2017	
2018	
2019	36 MW of Recipricating Engines
2020	200 MW of Combined Cycle
	NPV $3,475 million

2) 2013 ORC with 107.5 MW of Owned Wind

2015	L&C MATS Project
	73 MW of Recipricating Engines
2016	107.5 MW of Owned Wind
2017	
2018	
2019	36 MW of Recipricating Engines
2020	200 MW of Combined Cycle
	NPV $3,445 million

3) 2013 ORC with no new wind

2015	L&C MATS Project
	73 MW of Recipricating Engines
2016	
2017	36 MW of Recipricating Engines
2018	
2019	
2020	200 MW of Combined Cycle
	NPV $3,574 million


Montana-Dakota Utilities Co. Peak Customer Load and Annual Energy Requirements
1985-2014
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
700
600
500
400
300
200
100
0
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Requirements (MWh)
Summer Peak Load (MW)
Winter Peak Load (MW)

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Electric Service	)))))	Docket No. D2015.6__

DIRECT TESTIMONY AND EXHIBITS

OF

EARL M. ROBINSON

On The Subject of Depreciation

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I. WITNESS INTRODUCTION

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

A. My name is Earl M. Robinson. I am a Principal and Director of AUS Consultants. AUS Consultants is a consulting firm specializing in preparing various financial studies including depreciation, valuation, revenue requirements, cost of service, rate of return, and other analysis and studies for the utility industry and numerous other entities. AUS Consultants provides a wide spectrum of consulting services through its practices that include Depreciation & Valuation, Intellectual Property Management, Knowledge Management, Rate of Return, Revenue Requirements & Cost of Service, and Education & Publications. My office is located at 792 Old Highway 66, Suite 200, Tijeras, NM 87059.

Q2. Have you prepared an appendix which contains your qualifications and experience?

A. Yes. Appendix A to my direct testimony contains a summary of my qualifications and experience.

II. PURPOSE OF TESTIMONY

Q3. What is the purpose of your testimony?

A. The purpose of my testimony is to set forth the results of my depreciation review and analysis of the plant in service of Montana-Dakota Utilities Co.-Electric Division and Common Plant ("Company") which was conducted in the process of preparing depreciation studies of the Company's electric and common plant assets as of December 31, 2014. Reports of my review and analyses are contained in Exhibit No. ___(EMR-1), titled

"Montana-Dakota Utilities Co-Electric Division Depreciation Study as of December 31, 2014" and Exhibit No._____(EMR-2), the "Montana-Dakota Utilities Co.-Common Plant Depreciation Study as of December 31, 2014". In preparing the report, I investigated and analyzed the Company's historical plant data and reviewed the Company's past experience and future expectations to determine the remaining lives of the Company's electric and common plant assets. The studies utilized the resulting remaining lives, the results of a salvage analysis, the Company's vintaged plant in service investment and depreciation reserve to develop recommended average remaining life depreciation rates and depreciation expense related to the Company's plant in service.

III. BACKGROUND

Q4. How is depreciation defined?

A. Depreciation is defined in the 1996 NARUC "Public Utility Depreciation Practices" publication as follows: "Depreciation, as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities."

Q5. Why is depreciation important to the revenue requirements of a utility company?

A. Depreciation is important because, as the above definition describes, depreciation expense enables a company to recover in a timely manner the capital costs related to its plant in service benefiting the company's customers. Appropriate depreciation rates will allow recovery of a company's investments in depreciable assets over a life that provides for full recovery of the investments, less net salvage. Without the appropriate recovery of depreciation costs, the Company ultimately will not be able to meet its financial obligations related to the continued provision of service to customers. Furthermore, the inclusion of the appropriate level of depreciation recovery in revenue requirements serves to reduce overall costs (total of depreciation and return) to customers as opposed to a situation where an inadequate level of annual depreciation expense is currently being provided in rates.

IV. DEPRECIATION STUDY OVERVIEW

Q6. What is your professional opinion with regard to the results of the depreciation study that you performed?

A. In my opinion, the proposed depreciation rates resulting from the completed comprehensive depreciation study are reasonable and appropriate given that they incorporate the service life and net salvage parameters currently anticipated for each of the Company's property group investments over their average remaining lives.

1 **Q7. What steps were involved in preparing the service life and salvage**
2 **database that you utilized?**
3 **A.** My comprehensive depreciation analyses included a detailed analysis of
4 the Company's fixed capital books and records through December 31,
5 2014. The Company's historical investment cost records for each account
6 have been assembled into a depreciation database upon which detailed
7 service life and salvage analysis were performed using standard
8 depreciation procedures.
9 **Q8. What is the purpose of the historical database?**
10 **A.** The historical service life and net salvage data is a basic depreciation
11 study tool that is assembled to prepare a depreciation study. The
12 historical database is used to make assessments and judgments
13 concerning the service life and salvage factors that have actually been
14 achieved, and (along with information relative to current and prospective
15 factors) to determine the appropriate future lives over which to recover the
16 Company's depreciable fixed capital investments. In accordance with this
17 standard depreciation analysis, the Company's depreciation database
18 compiled through December 31, 2014, which contains detailed vintage
19 level information, was used to develop observed life tables. The
20 development of the observed life tables from the historical information was
21 completed by grouping like aged investments within each property
22 category and identifying the level of retirements that occur through each
23 successive age to develop the applicable observed life tables. The

resulting observed lives were then fitted to standard Iowa Curves to estimate each property group's historically achieved average service life.

Likewise, the net salvage database was used as a basis to identify historical experience and trends and to determine each property group's recommended net salvage factors. This was accomplished by preparing various three year rolling band analyses of salvage components as well as a forecast based on the Company's historical salvage experience.

Q9. In the preparation of the depreciation study, have you utilized information from additional sources when estimating service life and salvage parameters?

A. Yes. In addition to the historical data obtained from the Company's books and records, information was obtained from Company personnel relative to current operations and future expectations with respect to depreciation. Discussions were held with Company planning and operations management. In addition, physical inspections were also conducted of various representative sites of the Company's operating property.

Q10. Please briefly describe the information included in the depreciation study reports.

A. The electric depreciation study report is divided into eight (8) sections, while the Common Plant depreciation study report is divided into seven (7) sections. Section 1 of each of the reports contains a brief narrative summary of the respective report. Two key portions of each of the reports are Sections 2 and 4. Section 2 includes the summary schedules listing the present and proposed depreciation rates for each depreciable property

group and other depreciation rate development schedules. Section 4 contains a narrative description of the factors considered in selecting service life parameters for the Company's property. The various other sections of the report contain detailed information and/or documentation supporting the schedules contained in Sections 2 and 4. Section 3 of the reports contain a general narrative explaining methods, procedures, and techniques, etc. universally used in the preparation of depreciation studies. In addition, Section 5 is the graphical presentation of the average service life analysis, Section 6 is the detailed Average Remaining Life calculations, and Section 8 for the Electric study, (Section 7 for the Common Plant study) is the detailed Net Salvage analysis schedules. Section 7 of the Electric study is the supporting calculations for the theoretical depreciation reserve calculations used to allocate the booked depreciation reserves relative to selected sub-account levels.

Q11. What was the source of the data utilized as a basis for determining the depreciation rates?

A. As previously discussed, all of the historical data utilized in the course of performing the detailed service life and salvage study was obtained from the Company's books and records. Historical vintaged data (additions, retirements, adjustments, and balances) were obtained for each depreciable property group.

Q12. Are there standard methods utilized to complete a service life analysis of a company's historical property investments?

1 **A.** Yes. As discussed in Section 3 of the depreciation study report as well as
2 later in this testimony, the two most common methods are the Retirement
3 Rate Method and the Simulated Plant Record Method. The method
4 chosen to study a company's historical data is dependent upon whether
5 aged or un-aged data is available. If specific aged data is available, the
6 Retirement Rate Method is used. If only un-aged data is available, the
7 Simulated Plant Record Method is used.

8 **Q13. Were your studies prepared utilizing one of these accepted standard**
9 **methods?**

10 **A.** Yes. Aged plant records for the Company's property is available for a
11 period of years, therefore, the Retirement Rate Method of life analysis was
12 utilized in the depreciation studies of the Company's property.

13 **V. METHODS, PROCEDURES & TECHNIQUES**

14 **Q14. Please describe the depreciation methods, procedures, and**
15 **techniques commonly utilized to develop depreciation rates for**
16 **utility property**.

17 **A.** Inherent in all depreciation calculations is an overall method, such as the
18 Straight Line Method (which is the most widely used approach within the
19 utility industry) to depreciate property. Other methods available to develop
20 average service lives and depreciation rates are accelerated and/or
21 deferral approaches such as the Sum of the Years Digits Method or
22 Sinking Fund Method.

23 In addition, there are several procedures that can be used to
24 arrange or group property by sub-groups of vintages to develop applicable

service lives. These procedures include the Broad Group, the Equal Life Group and other procedures. Due to the existence of very large quantities of property units within utility operating property, utility property is typically grouped into homogeneous categories as opposed to being depreciated on an individual unit basis. While the Equal Life Group procedure is viewed as being the more definitive procedure for identifying the life characteristics of utility property and as a basis for developing service lives and depreciation rates, the Broad Group Procedure is more widely utilized throughout the utility industry by regulatory commissions as a basis for depreciation rates. My comments on the Equal Life Group procedure are discussed later in my testimony.

The distinction between the two procedures is in the manner in which recovery of the cost is achieved. Under the Broad Group Procedure, the useful life and resulting depreciation rate is based upon the overall average life of all of the property within the group, while under the Equal Life Group Procedure, the useful life and resulting depreciation rate is based upon separately recovering the investment in each equal life group within the property category over the actual life of the property in that group.

A brief example (with a property group that has three units/three equal life groups of like property) will demonstrate the difference between the two procedures. The example incorporates the assumption that unit No. 1 (or equal life group of property) will retire after one year, unit No. 2 (or equal life group) will retire after two years, and Unit No. 3 (or equal life

group) will retire after three years. Accordingly, the average life of all three (groups) is two (2) years (1+2+3)÷3. Under the Broad Group Procedure, the average useful life and resulting depreciation rate is calculated based upon the two (2) year average life. The resulting annual depreciation rates would be fifty (50) percent in every year. Conversely, under the Equal Life Group Procedure, each year's average life and resulting depreciation rate is calculated by using the period of time during which the portion of the property group remains in service. Since unit No. 1 (or that portion of the account) was retired from service after one year, the entire investment for that property is recovered over one (1) year. Likewise, since unit No. 2 (or that portion of the account) will have a service life of two years, the recovery of that portion of the account will occur over two years. Lastly, unit No. 3 (or that portion of the account) is recovered over three years. Hence, the useful average life for the property group in the first year is 1.64 years and the first year's annual depreciation rate is 61.11 percent. In the second year, the useful average life of the surviving group is 2.4 years and the second year's depreciation rate drops to 41.67 percent. This occurs because during the first year, unit No. 1 (or that portion of the account) was fully recovered. Likewise, in year three the useful life of the surviving group is 3 years and the depreciation rate further drops to 33.33 percent. See the following Table EMR-1 (BG and ELG).

		BG Average Life Calculation				BG Depreciation Rate Calculation			
Year		Investment	Recovery Period (Yrs)	ASL (Years)	Weight	Investment	Recovery Period (Yrs)	Annual Rate-%	Recovery Amount
1	Group # 1	300	2		150	300	2		150
	Group # 2	300	2		150	300	2		150
	Group # 3	300	2		150	300	2		150
	Total	900		2.00	450	900		50.00%	450
2	Group # 1	0	0		0	0	0		0
	Group # 2	300	2		150	300	2		150
	Group # 3	300	2		150	300	2		150
	Total	600		2.00	300	600		50.00%	300
3	Group # 1	0	0		0	0	0		0
	Group # 2	0	0		0	0	0		0
	Group # 3	300	2		150	300	2		150
	Total	300		2.00	150	300		50.00%	150
Grand Total		1,800		2.00	900	1,800		50.00%	900

		ELG Average Life Calculation				ELG Depreciation Rate Calculation			
Year		Investment	Recovery Period (Yrs)	ASL (Years)	Weight	Investment	Recovery Period (Yrs)	Annual Rate-%	Recovery Amount
1	Group # 1	300	1		300	300	1		300
	Group # 2	300	2		150	300	2		150
	Group # 3	300	3		100	300	3		100
	Total	900		1.64	550	900		61.11%	550
2	Group # 1	0	0		0	0	0		0
	Group # 2	300	2		150	300	2		150
	Group # 3	300	3		100	300	3		100
	Total	600		2.40	250	600		41.67%	250
3	Group # 1	0	0		0	0	0		0
	Group # 2	0	0		0	0	0		0
	Group # 3	300	3		100	300	3		100
	Total	300		3.00	100	300		33.33%	100
Grand Total		1,800		2.00	900	1,800		50.00%	900

Finally, the depreciable investment needs to be recovered over a defined period of time (through use of a technique), such as the Whole Life or Average Remaining Life of the property group. The distinction between the Whole Life and Average Remaining Life Techniques is that under the Whole Life Technique, the depreciation rate is based on a snapshot and determines the recovery of the investment and average net salvage over the average service life of the property group for that moment in time. The Whole Life technique requires either frequent updates to keep the "snapshot" current or the use of an artificial deferred account that holds "excess" or "deficient" depreciation reserves. In comparison, under the Average Remaining Life Technique, the resulting annual depreciation rate incorporates the recovery of the investment (and future net salvage) less any recovery experienced to date over the average remaining life of the property group. The Average Remaining Life Technique is clearly superior in that it incorporates all of the current and future cost components in setting the proposed annual depreciation rate as opposed to only some of the current and future cost components as is the case with the Whole Life Technique. This means that any changes that occur in between depreciation studies are automatically trued-up in the subsequent study. No artificial deferral account needs to be established to accomplish such a true-up.

The depreciation methods, procedures, and techniques can be used interchangeably. For example, one could use the Straight Line Method

with the Broad Group Procedure and the Average Remaining Life Technique, or the Straight Line Method with the Equal Life Group Procedure and Average Remaining Life Technique, or combinations thereof.

Q15. Which of these methods, procedures and techniques did you use in your depreciation studies?

A. The depreciation rates set forth in my depreciation study reports were developed utilizing the Straight Line Method, the Broad Group Procedure, and the Average Remaining Life Technique.

Q16. If you did not use the Equal Life Group Procedure in the development of the Company's depreciation rates, why did you spend time explaining the process?

A. The discussion of the various/significant methods, procedures, and techniques, and specifically the Equal Life Group Procedure, is an ongoing education process. That is, the discussion is presented to insure that there is an understanding of principal available depreciation processes and their benefits, notwithstanding any unwillingness and/or objection to the use of a more defined and correct procedure, i.e. the Equal Life Group Procedure.

Q17. Why did you utilize the method, procedure, and technique incorporated within the proposed depreciation rates?

A. The Straight Line Method is widely understood, recognized, and utilized almost exclusively for depreciating utility property.

1 The Broad Group Procedure recovers the Company's investments
2 over the average period of time in which the property is providing service to
3 the Company's customers. While I have used the Equal Life Group
4 procedure in other studies, I used the Broad Group Procedure in this study
5 because it is consistent with depreciation methods and procedures
6 generally accepted by regulatory Commissions plus it is the approach
7 underlying the Company's current depreciation rates.

8 Finally, the amount of annual depreciation must be based upon the
9 productive life over which the un-depreciated capital investment is
10 recovered (the Average Remaining Life Technique). The utilization of the
11 Average Remaining Life Technique to develop the applicable annual
12 depreciation expense (over the average remaining life) assures that the
13 Company's property investment is fully recovered over the useful life of the
14 property, and that inter-generational inequities are avoided as current and
15 future customers will pay their fair share of depreciation expense. The
16 determination of the productive remaining life for each property group relies
17 on a study of both past experience and future expectations and develops
18 the appropriate total life and applicable depreciation rates for each of the
19 Company's property groups. The Average Remaining Life Technique
20 incorporates all of the Company's fixed capital cost components, thereby
21 better assuring full recovery of the Company's embedded net plant
22 investment and related costs. The Average Remaining Life Technique
23 gives consideration not only to the average service life and survival

characteristics plus the net salvage component, but also recognizes the level of depreciation which has been accrued to date in developing the proposed depreciation rate. The Average Remaining Life Technique is used by regulated companies and regulatory agencies because it allows full recovery by the end of the property's useful life -- no more and no less.

VI. GROUP DEPRECIATION

Q18. Please explain the utilization of group depreciation.

A. Group depreciation is utilized to depreciate property when more than one item of property is being depreciated. Such an approach is appropriate because all of the items within a specific group typically do not have identical service lives, but have lives which are dispersed over a range of time. Utilizing group depreciation allows for a uniform application of depreciation rates to groups of similar property in lieu of performing extensive depreciation calculations on an item-by-item basis. The Broad Group approach is a recognized common group depreciation procedure.

The Broad Group Procedure recovers the investment within the asset group over the average service life of the property group. Given that there is dispersion within each property group, there are variations of retirement ages for the many investments within each property group. That is, some properties retire early (before average service life) while others retire at older ages (after average service life). This dispersion of retirement ages defines the survival pattern experienced by the applicable property group.

1 **Q19. What factors influence the determination of the recommended annual**
2 **depreciation rates included in your depreciation reports?**
3 **A.** The depreciation rates reflect four principal factors: (1) the plant in service
4 by vintage, (2) the book depreciation reserve, (3) the future net salvage,
5 and (4) the composite remaining life for the property group. Factors
6 considered in arriving at the service life are the average age, realized life
7 and the survival characteristics of the property. The net salvage estimate
8 is influenced by both past experience and future estimates of the cost of
9 removal and gross salvage amounts.
10 **Q20. Please explain further the assumptions considered when utilizing**
11 **your depreciation approach**.
12 **A.** According to the approach, the Company will recover its un-depreciated
13 fixed capital investment through annual depreciation expense in each year
14 throughout the useful life of the property. The Average Remaining Life
15 Technique incorporates the future life expectancy of the property, the
16 vintaged surviving plant in service, the survival characteristics, together
17 with the book depreciation reserve balance and future net salvage in
18 developing the amounts for each property account. Accordingly, Average
19 Remaining Life depreciation meets the objective of providing a Straight
20 Line recovery of the Company's fixed capital property investments.
21 **Q21. Do you have additional comments related to the group approach that**
22 **you have used?**

1 **A.** Yes, my depreciation calculations, as applied in this study, follow a group
2 depreciation approach. The group approach refers to the method of
3 calculating annual depreciation based on the summation of the investment
4 in any one plant group rather than calculation of depreciation for each
5 individual unit of plant. In theory, each unit achieves average service life
6 by the time of retirement. Accordingly, the full cost of the investment will be
7 credited to plant in service when the retirement occurs, and likewise the
8 depreciation reserve will be debited with an equal retirement cost. No gain
9 or loss is recognized at the time of property retirement because of the
10 assumption that the property was retired at average service life.

11 **VII. NET SALVAGE**

12 **Q22. What are the net salvage factors included in the determination of**
13 **depreciation rates?**

14 **A.** Net salvage is the difference between gross salvage, or the proceeds
15 received when an asset is disposed of, and the cost of removing the asset
16 from service. Net salvage is said to be positive if gross salvage exceeds
17 the cost of removal. If the cost of removal exceeds gross salvage, the
18 result is negative salvage. Many retired assets generate little, if any,
19 positive salvage. Instead, numerous Company asset groups generate
20 negative net salvage at the end of their lives due to the cost of removal.

21 The cost of removal includes costs such as demolishing, dismantling,
22 tearing down, disconnecting or otherwise retiring/removing plant, as well as
23 any environmental clean-up costs associated with the property. Net
24 salvage includes any proceeds received from any sale of plant.

Net salvage experience is studied for a period of years to determine the trends which have occurred in the past. These trends are considered, together with any changes that are anticipated in the future, to determine the future net salvage factor for remaining life depreciation purposes. The net salvage percentage is determined by comparing the total net positive or negative salvage to the book cost of the property investment retired.

The method used to estimate the retirement cost is a standard analysis approach which is used to identify a company's historical experience with regard to what the end of life cost will be relative to the cost of the plant when first placed into service. This information, along with knowledge about the average age of the historical retirements that have occurred to date, allows an estimation of the level of retirement cost that will be experienced by the Company at the end of each property group's useful life. The study methodology utilized has been extensively set forth in depreciation textbooks and has been the accepted practice by depreciation professionals for many decades. Furthermore, the cost of removal analysis is the current standard practice used for mass assets by essentially all depreciation professionals in estimating future net salvage for the purpose of identifying the applicable depreciation rate for a property group. There is a direct relationship between the installation of specific plant and its corresponding removal. The installation is its beginning of life cost while the removal is its end of life cost. Also, it is important to note that Average Remaining Life depreciation rates incorporate future net

1 salvage which is typically more representative of recent versus long-term
2 historical average net salvage.

3 The Company's historical net salvage experience was analyzed to
4 identify the historical net salvage factor for each applicable property group
5 and is included in Section 8 of the Electric Division study and Section 7 of
6 the Common Plant study. This analysis routinely finds that historical
7 retirements have occurred at average ages significantly shorter than the
8 property group's average service life. The occurrence of historical
9 retirements at an age which is significantly younger than the average
10 service life of the property category demonstrates that the historical data
11 does not appropriately recognize the true level of retirement cost at the end
12 of the property group's useful life. An additional level of cost to retire will
13 occur due to the passage of time until all the current plant is retired at end
14 of its life. That is, the level of retirement costs will increase over time until
15 the average service life is attained. The additional inflation in the estimate
16 of retirement cost is related to those additional years' cost increases
17 (primarily the result of higher labor costs over time) that will occur prior to
18 the end of the property group's average life.

19 To provide further explanation of the issue, several general
20 principles surrounding property retirements and related net salvage should
21 be highlighted. As property continues to age, assets that typically generate
22 positive salvage when retired will generate a lower percentage of positive
23 salvage as compared to the original cost of the property. By comparison, if

the class of assets is one that typically generates negative net salvage (cost of removal) with increasing age at retirement, the negative net salvage percentage as compared to original cost will typically be greater. This situation is routinely driven by the higher labor costs that occur with the passage of time.

A simple example will aid in understanding the above net salvage analysis and the required adjustment to the historical results. Assume the following scenario: A company has two cars, Car #1 and Car #2, each purchased for $20,000. Car #1 is retired after 2 years and Car #2, is retired after 10 years. Accordingly, the average life of the two cars is six (6) years. Car #1 generates 75% salvage or $15,000 when retired and Car #2 generates 5% salvage or $1,000 when retired.

	Unit Cost	Ret. Age (Yrs.)	% Salv.	Salvage Amount
Car #1	$20,000	2	75%	$15,000
Car #2	$20,000	10	5%	$ 1,000
Total	$40,000	6	40%	$16,000

Assume an analysis of the experienced net salvage at year three (3). Based upon the Car #1 retirement, which was retired at a young age (2 yrs.) as compared to the average six (6) year life of the property group, the analysis indicates that the property group would generate 75% salvage. This indication is incorrect, however, because it is the result of basing the

estimate on incomplete data. That is, the estimate is based upon the salvage generated from a retirement that occurred at an age which is far less than the average service life of the property group. The actual total net salvage that occurred over the average life of the assets (which experienced a six (6) year average life for the property group) is 40%, as opposed to the initial incorrect estimate of 75%.

This is exactly the situation that occurs with the majority of the Company's historical net salvage data, except that most of the Company's property groups routinely experience negative net salvage (cost of removal) as opposed to positive salvage.

VIII. DEPRECIATION STUDY ANALYSIS

Q23. Please explain what factors affect the length of the average service life that the Company's property may achieve.

A. Several factors contribute to the length of the average service life which the property achieves. The three major factors are: (1) physical; (2) functional; and (3) contingent casualties.

The physical factor includes such things as deterioration, wear and tear and the action of the natural elements. The functional factor includes inadequacy, obsolescence and requirements of governmental authorities. Obsolescence occurs when it is no longer economically feasible to use the property to provide service to customers or when technological advances have provided a substitute with superior performance. The remaining factor, contingent casualties, includes retirements caused by accidental damage or construction activity of one type or another.

1 In performing the life analysis for any property being studied, both
2 past experience and future expectations must be considered in order to
3 fully evaluate the circumstances that may have a bearing on the remaining
4 life of the property. This ensures the selection of an average service life
5 which best represents the expected life of each property investment.

6 **Q24. What study procedures were utilized to determine service lives for the**
7 **Company's property?**

8 **A.** Several study procedures were used to determine the prospective service
9 lives recommended for the Company's plant in service. These include the
10 review and analysis of historical, as well as anticipated, retirements, current
11 and future construction technology, historical experience and future
12 expectations of salvage and the cost of removal.

13 Service lives are affected by many different factors, some of which
14 can be determined from studying past experience, others of which must
15 rely heavily on future expectations. When physical characteristics are the
16 controlling factor in determining the service life of property, historical
17 experience is a useful tool in selecting service lives. In cases where there
18 are changes in technology, regulatory requirements, Company policy or the
19 development of a less costly alternative, historical experience is of lesser or
20 little value. However, even when considering physical factors, the future
21 lives of various properties may vary from those experienced in the recent
22 past.

While a number of methods are available to study historical data, as I mentioned previously, the two methods most commonly utilized to determine average service lives for a company's property are the Retirement Rate Method and the Simulated Plant Record Method. Aged plant records for the Company's property is available for a period of years, therefore, the Retirement Rate Method of life analysis was utilized in the depreciation studies of the Company's property.

Q25. Please explain the use of the retirement rate method.

A. With this method of analysis, the Company's actuarial service life data, which is sorted by age, is used to develop a survivor curve (observed life table). This survivor curve is the basis upon which smooth curves (standard Iowa Curves) are matched or fitted to then determine the average service life being experienced by the property account under study. Computer processing provides the capability to review various experience bands throughout the life of the account to observe trends and changes. For each experience band analysis, an "observed life table" is constructed using the exposure and retirement experience within the selected band of years. In some cases, the total life cycle of the property has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is the "stub curve," or the total life curve, if the total life curve is achieved, which is matched or fitted to the standard Iowa Curves. The matching process is performed both by computer analysis, using a least squares technique, and by overlaying the observed life tables on the

selected smooth curves for visual reference. The fitted smooth curve is a benchmark which provides a basis to determine the estimated average service life for the property group under study.

Q26. Do the depreciation study reports contain charts which compare the analysis of the Company's actual historical data to the service life parameters you are proposing as a basis for your recommended annual depreciation rates?

A. Yes. Graphical representations of the Company's plant balances versus simulated plant balances based upon the estimated lives and Iowa Curves are contained in Section 5 of the reports.

Q27. You have referred to the use of the Iowa or smoothed survivor curves. Can you generally describe these curves and their purpose?

A. The preparation of a depreciation study typically incorporates smoothed curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves are the "Iowa" family of curves developed at Iowa State University and which are widely used and accepted throughout the utility industry. The shape of the curves within the Iowa family is dependent upon whether the maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if it occurs at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right (R) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

At any particular point in time, actual Company plant may not have completed its life cycle. Therefore, the survivor table generated from the Company data is not complete. This situation requires that an estimate be made with regard to the incomplete segment of the property group's life experience. Further, actual company experience often varies from age interval to age interval, making its utilization for average service estimation difficult. Accordingly, the Iowa Curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Q28. What is the principal reason for completing the detailed historical life and salvage analysis?

A. The detailed historical analysis is prepared as a tool from which to make informed assessments as to the appropriate service life and salvage parameters over which to recover the Company's plant investment. However, in addition to the available historic data, consideration must be given to current events, the Company's ongoing operations, Company management's future plans, and general industry events which are anticipated to impact the lives that will be achieved by plant in service.

IX. COMPREHENSIVE DEPRECIATION STUDY RESULTS AS OF 12-31-14

Q29. What is the basis for the Company's currently approved Electric depreciation rates?

A. As shown in Exhibit No. ___(EMR-1), Table 1, pages 2-1 to 2-2, the prior depreciation rates for the plant were based upon depreciation parameters

1 set forth in a study completed using the Company's Electric plant
2 investment data through December 31, 2008. The current account level
3 depreciation rates composite to an annual depreciation rate of 2.88 percent
4 when applied to each of the December 31, 2014 plant in service account
5 balances.

6 **Q30. What are the most notable changes in annual depreciation rates and**
7 **expense between the present and proposed depreciation rates as set**
8 **forth in Section 2 of the Montana-Dakota Electric depreciation report?**

9 **A.** With regard to plant in service, several of the proposed rates reflect
10 changes (as outlined in Section 4 of the study) from the current
11 depreciation rates.

12 The most notable depreciation/amortization occurred relative to
13 Account 312 – Boiler Plant Equipment, Account 344.10 – Generators,
14 Account 344.20 – Generators-Wind Farm, Account 353 – Station
15 Equipment, Account 355 – Poles and Fixtures, and Account 370 – Meters.

16 The depreciation rate for Account 312 – Boiler Plant Equipment
17 increased from 2.46 percent to 2.71 percent. The proposed depreciation
18 rate for the Company's investment in this property category is being
19 developed via the Life Span Method. An interim retirement rate was
20 identified for each property group based upon an analysis of the
21 Company's historical experience to date. Using the location and vintage
22 level surviving investments for each generating facility's location property,
23 the estimated interim retirement rate and Company management's

1 provided probable retirement/rehabilitation dates, an implicit average
2 service life and average remaining life was produced via the life span
3 approach. The developed depreciation rates do not include any proposed
4 component for the recovery of either interim or terminal (decommission
5 cost) net salvage. The end of life terminal negative net salvage
6 (decommissioning cost), is addressed separately in this rate case.
7 Company management requested that interim negative net salvage not be
8 included in the development of the proposed depreciation rates related to
9 its generating facilities at this time.

10 Ongoing additional new investments added to existing life span
11 property class investments (absent changes in underlying parameters)
12 automatically reduces the implicit average life and increases the required
13 depreciation rate due to the fact that in each successive year there is a
14 shorter period of time over which to recover the added investments.

15 The depreciation rate for Account 344.10 – Generators increased
16 from 2.60 percent to 3.00 percent. The Company has multiple Other
17 Production units including Glendive, Glendive II, Miles City, Heskett III,
18 Ormat Generation, and Portable Generators at various locations. Not all of
19 the various locations have investments in each of the Other Production
20 property accounts.

21 The depreciation rate for the Company's investment in this property
22 category is being developed via the Life Span Method. An interim
23 retirement rate was identified for each property group based upon an

analysis of the Company's total account historical experience to date. Using the location and vintage level surviving investments for each generating facility's location property, the estimated interim retirement rate and Company management's provided probable retirement/rehabilitation dates, an implicit average service life and average remaining life was produced via the life span approach. The developed depreciation rates do not include any proposed component for the recovery of either interim or terminal (decommission cost) net salvage. The end of life terminal negative net salvage (decommissioning cost), is addressed separately in this rate case. Company management requested that interim negative net salvage not be included in the development of the proposed depreciation rates related to its generating facilities at this time.

Similarly like the forgoing accounts, the ongoing additional new investments added to existing life span property class investments (absent changes in underlying parameters) automatically reduces the implicit average life and increases the required depreciation rate due to the fact that in each successive year there is a shorter period of time over which to recover the added investments.

The depreciation rate for Account 344.2-Generators-Wind Farm increased from 5.06 percent to 5.52 percent. The Company has 2 wind farm sites, namely, Diamond Willow and Cedar Hills. Diamond Willow currently has 20 turbine units while the Cedar Hills is comprise of 13 turbine units. The capacity of each of the Diamond Hills turbines is 1.5

1 MW and the Cedar Hills turbines are 1.5 MW each.

2 The depreciation rate for the Company's investment in this property
3 category is being developed via the Life Span Method. An interim
4 retirement rate was identified for each property group based upon an
5 analysis of the Company's total account historical experience to date.
6 Using the location and vintage level surviving investments for each
7 generating facility's location property, the estimated interim retirement rate
8 and Company management's provided probable retirement/rehabilitation
9 dates, an implicit average service life and average remaining life was
10 produced via the life span approach. The developed depreciation rates do
11 not include any proposed component for the recovery of either interim or
12 terminal (decommission cost) net salvage. The end of life terminal negative
13 net salvage (decommissioning cost), is addressed separately in this rate
14 case. Company management requested that interim negative net salvage
15 not be included in the development of the proposed depreciation rates
16 related to its generating facilities at this time.

17 Similarly, like the forgoing accounts, the ongoing additional new
18 investments added to existing life span property class investments (absent
19 changes in underlying parameters) automatically reduces the implicit
20 average life and increases the required depreciation rate due to the fact
21 that in each successive year there is a shorter period of time over which to
22 recover the added investments.

23 The proposed depreciation rate for Account 353– Station Equipment,

1 declined from 1.88 percent to 1.58 percent. The proposed depreciation
2 rate is the result of combined changes of the average service life
3 parameters as well as the changes to plant in service and the applicable
4 book depreciation reserve. The proposed average service life was
5 changed in accordance with the life indication developed through an
6 analysis of the Company's historical data and consideration of future
7 expectations. The resulting proposed average service life is sixty (60)
8 years, while the average service life underlying the present depreciation
9 rate is forty-five (45) years. Both the future net salvage underlying the
10 proposed depreciation rates and the net salvage underlying the present
11 depreciation rates is negative 10 percent.

12 The costs included in this account investment are related to
13 numerous transmission substation equipment (including items such as
14 transformers, voltage regulators, circuit breakers, etc.) used to transform
15 power to different voltages. Currently, there are nearly 100 stations
16 operating at voltages between 69Kv through 138 & 345Kv facilities. During
17 the last several years the Company has been in an increasing growth
18 mode having increased its plant investment by approximately a third. To
19 date the activity has been more on the growth side as opposed to
20 replacement of existing facilities. In future years it is anticipated that
21 replacement of existing facilities will likely occur at higher levels, thus the
22 average service life should be monitored closely. At the current estimated
23 average service life, the recovery period is longer than the maximum

1 average service life for the property group identified in an industry survey.

2 The proposed depreciation rate for Account 355 – Poles and
3 Fixtures, increased from 2.40 percent to 2.99 percent. The proposed
4 depreciation rate is the result of combined changes of both the average
5 service life and net salvage parameters. The proposed average service life
6 changed in accordance with the life indication developed through an
7 analysis of the Company's historical data and consideration of future
8 expectations. The resulting proposed average service life is fifty (50) years,
9 which is an increase from the forty-five (45) year average service life
10 underlying the present depreciation rate. The future net salvage underlying
11 the proposed depreciation rates is negative fifty (50) percent while the
12 future net salvage underlying the present depreciation rates is negative
13 thirty-five (35) percent and is reflective of the increased level of negative
14 net salvage being experienced by the company.

15 During the last several years the Company has been in an
16 increasing growth mode having increased its plant investment by
17 approximately a third. Historically, the activity has been more on the
18 growth side as opposed to replacement of existing facilities, however,
19 during the most recent study year replacements/retirements have
20 accelerated rather dramatically. In fact while the overall and more recent 5
21 year experience band analysis produced life indication of an estimated 57
22 years' average service life, the current 2014 band produced an average
23 service life indication of 45 years. In future years it is anticipated that

1 replacement of existing facilities will likely occur at higher levels.

2 Over the immediate coming 5 years management anticipates
3 building approximately 100 miles of pole transmission line of which one half
4 is expected to meet continued growth/expansion while the remaining one
5 half is expected to be replacement of existing property with further activity
6 in more distant years. This significant increase in plant activity can be
7 anticipated to continue the shorter life presently being experienced. Based
8 upon the available recent study result a reduction to the longer than normal
9 average service life for the Company's property is proposed. At the
10 present time, an average service life of 50 years is estimated for the
11 property group. As additional activity occurs in future years a further
12 reduction will likely be warranted. Even at the estimated average service
13 life of a 50-R3 life and curve, the recovery period is at the higher end of the
14 industry range of service lives.

15 The proposed depreciation rate for Account 370– Meters, increased
16 from 3.44 percent to 7.19 percent. The proposed depreciation rate is the
17 result of combined changes of both the average service life and net
18 salvage parameters. The resulting proposed composite average service life
19 twenty (20) years, while the average service life underlying the present
20 depreciation rate is thirty-five (35) years. The future net salvage underlying
21 the proposed depreciation rates is negative 5 percent while the future net
22 salvage underlying the present depreciation rates is 0 percent.

23 In more recent years, the Company replaced the overwhelming

1 majority of its electric meters in conjunction with an AMR conversion
2 project. Accordingly, the historical analysis of recent data, in which there
3 was a wholesale change out of property, produced a shorter life indication
4 for the property group than might be experienced for the current property.
5 That is, the conversion project resulted in the Company now having a
6 completely different automated metering reading (AMR) technology of
7 Meters than which previously existed. This current new technologically
8 driven property is routinely influenced by greater levels of upgrades,
9 obsolescence, etc. than the prior mechanical meters.

10 For example, while the AMR technology provides improved
11 efficiencies and enhanced technology capabilities, it only captures a limited
12 part of the ultimate transformation to the current state of the art meter
13 reading and plant utilization capabilities. Advanced Meter Infrastructure
14 (AMI) and related Smart Grid will further expand the control capabilities of
15 the electric network. Accordingly, it is only a matter of time until it will be
16 necessary to complete further upgrades to its present Meter facilities. Thus,
17 an average service life of 20 years is initially estimated for the present
18 property group investment. The life of this property group needs to be
19 monitored on an ongoing basis in conjunction with changing technology
20 and the Company's needs to address such rapid changes.

21 **Q31. What is the basis for the Company's currently approved Common**
22 **Plant depreciation rates?**

1 **A.** As shown in Exhibit No. ___(EMR-2), Table 1, pages 2-1 to 2-2 of the
2 Common Plant Depreciation Study, the prior depreciation rates for the plant
3 were based upon depreciation parameters set forth in a study completed
4 using the Company's plant investment data through December 31, 2008.
5 The current account level depreciation rates composite to an annual
6 depreciation rate of 3.89 percent when applied to each of the December
7 31, 2014 plant in service account balances.

8 **Q32. What are the most notable changes in annual depreciation rates and**
9 **expense between the present and proposed depreciation rates as set**
10 **forth in Section 2 of the Montana-Dakota Common Plant depreciation**
11 **report?**

12 **A.** With regard to plant in service, several of the proposed rates reflect
13 changes (as outlined in Section 4 of the study) from the current
14 depreciation rates.

15 The most notable depreciation/amortization change occurred
16 relative to Account 392.20 - Transportation Equipment - Cars & Trucks.

17 The depreciation rate relative to Account 392.20 - Transportation
18 Equipment - Cars & Trucks increased from 4.11 percent to 6.65 percent.
19 Contributing to the depreciation expense increase is the change in the
20 estimated average service life from seven to nine years while the future net
21 salvage estimate remained at 20%. However, the more significant driver of
22 the depreciation rate increase is the fact that the current book depreciation
23 reserve is currently lower than required in comparison to the current age of

the property group's investment.

X. NET CHANGE FROM 12-31-08 BOOK DEPRECIATION RATES TO PROPOSED DEPRECIATION

Q33. What is the net change to the composite electric depreciation rate under the proposed depreciation rates as applied to the December 31, 2014 plant in service in comparison to the application of the present depreciation rates?

A. Application of the proposed account level depreciation rates to the Company's plant in service as of December 31, 2014 produces a composite depreciation rate of 3.04 percent. By comparison, the application of the December 31, 2014 plant in service to the present account level depreciation rates to the Company's plant in service as of December 31, 2014 produces a composite depreciation rate of 2.88 percent.

Q34. What is the net change in electric annual depreciation expense under the proposed depreciation rates in comparison to the present depreciation rates?

A. Exhibit No.___(EMR-1), Section 2, Table 1, pages 2-1 to 2-2 produces a net increase in annualized depreciation expense of $1,993,230 when applying the proposed depreciation rates to the Company's plant in service investment as of December 31, 2014 in comparison to the depreciation expense produced by applying the current depreciation rates.

Q35. Have you prepared an exhibit which compares the composite depreciation rates produced when applying the proposed account

level deprecation rates to the Company's December 31, 2014 Common plant in service balances as compared to applying to the present depreciation rates?

A. Yes, that information is contained on Exhibit No.___(EMR-2), Pages 2-1 to 2-2 of the Common Plant Depreciation Study which shows the application of the proposed depreciation study account level depreciation rates to the Company's December 31, 2014 Common Plant in Service produces a composite depreciation rate of 4.30%, as compared to the application of the present account level depreciation rates that produces a composite depreciation rate of 3.89%.

Q36. What is the net change to the Company's Common Plant depreciation expense when applying the proposed depreciation rates to the December 31, 2014 plant in service in comparison to the annual depreciation expense when applying the present depreciation rates?

A. Exhibit No. ___(EMR-2) shows the application of the proposed December 31, 2014 depreciation study account level depreciation rates to the Company's Common plant in service as of December 31, 2014, which, as shown on page 2-1 of the exhibit, produces a net increase of annual depreciation expense of $275,554 as compared to that produced by applying the present depreciation rates.

XI. RECOMMENDATION

Q37. What is your recommendation in this proceeding?

1 **A.** I recommend that the proposed depreciation rates set forth in the
2 comprehensive depreciation study reports be uniformly and prospectively
3 adopted by the Commission for regulatory purposes as well as by the
4 Company for accounting purposes.

5 **Q38. Does this conclude your direct testimony?**

6 **A.** Yes, it does.

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Experience includes approximately 40 years of service in the public utility field. Mr. Robinson has performed services in the areas of depreciation, original cost, valuation, cost of service, and bill analysis within numerous regulatory jurisdictions and property tax agencies throughout the Eastern, Midwestern, Southwestern, and Pacific regions of the United States, Canada plus various areas of the Caribbean.

EXPERIENCE

1977 to Date

AUS Consultants. Various positions - currently Principal. Mr. Robinson has prepared studies and coordinated analysis related to valuation, depreciation, original cost, trended original cost, cost of service, bill analysis, as well as analysis of expenses, revenues and income for various municipal and an extensive number of investor-owned electric, gas, water, wastewater, and telecommunications utilities.

Studies prepared have required the review of company records, inspection of property, the preparation of property inventories and original costs, preparation and review of mortality studies, selection of proper service lives, life characteristics and analysis of salvage, and analysis of capital recovery impact of changing depreciation methods.

During his many years of experience, Mr. Robinson has been involved in and/or responsible for an extensive quantity of comprehensive depreciation studies. Numerous early year's depreciation studies were prepared manually without the convenience of computer software systems. Subsequent, during the mid/late 1970's, Mr. Robinson became responsible for the completion of the many depreciation studies performed for the firm's clients. As part of that responsibility, Mr. Robinson was involved in not only performing the studies, but also in assisting AUS Consultants' MIS department in developing and testing various computer depreciation models. The studies performed by Mr. Robinson or under his direction have included all types of utilities, including electric, gas, water, wastewater, and telecommunications. During Mr. Robinson's career he has been involved in the preparation of more than a hundred depreciation related projects.

A Certified Depreciation Professional (CDP), Mr. Robinson, as a Principal of AUS Consultants provides services to the firm's clients with regard to depreciation and cost based valuation issues. With more than forty (40) years' experience, he began his career as a staff member of the Plant Accounting Department of United Telephone (now Sprint) Eastern Group Headquarters subsequent to which he has spent the past thirty-five (35) plus years, as a consultant, preparing depreciation and valuation studies for gas, pipeline, electric, telecommunications, water, and wastewater utilities. In conjunction with the provision of these services, Mr. Robinson has testified on many occasions before numerous regulatory agencies (including state, federal, and property tax agencies throughout the U.S., Canada, and the Caribbean in support of the many studies completed for his diverse list of clients. In addition he has negotiated depreciation rates with various state regulatory agencies, the FCC Staff, and the FERC Staff. Mr. Robinson has also participated in several FCC, State, Company three-way depreciation re-prescription meetings.

With regard to valuation matters Mr. Robinson has been involved with the development of cost indexes from the earliest part of his career through the present. During his earlier years, he assisted and/or developed and utilized cost indexes to prepare reproduction cost and related fair value determinations for various of the firm's regulated utility clients. Subsequently, he attained extensive experience in preparing custom indexes, replacement cost, and depreciated replacement cost studies, having been responsible for preparing many such cost studies relative to various clients within the telecommunications industry during the past twenty (20) plus year period.

He is also responsible for developing and publishing the firm's AUS Telephone Plant Index

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

(successor to the Handy Whitman and C A Turner Telephone Construction Cost Index), a reproduction cost index subscribed to by various operating companies, regulatory agencies, and consultants.

Mr. Robinson is a founding member and past President of the Society of Depreciation Professionals, a professional organization that provides depreciation training, as well as provides a forum for discussion of depreciation issues. He is also a member of the American Gas Association (AGA) Accounting Services Committee and past chairman of the Statistics, Bibliography, Court Regulatory Sub-Committee of the AGA Depreciation Committee. As a member of that organization, he co-authored a publication entitled "An Introduction to Net Salvage of Public Utility Plant". Mr. Robinson has completed various previous presentations on the subject of depreciation studies as well as depreciated replacement cost to industry organizations and to property tax appraiser staffs.

1975 to 1977

Gannett, Fleming, Corddry & Carpenter, Inc. Valuation Analyst in the Valuation Division where his duties and responsibilities included the classifications, analysis and coordination of data in the development of depreciation rates for various companies including telephone, gas, water and electric utilities.

1971 to 1975

Weber, Fick & Wilson (Acquired by AUS Consultants), Public Utility Analyst engaged in the unitization and subsequent application of costs in the pricing of inventories for original cost determination, depreciation and salvage studies to determine proper annual depreciation rates and trended original cost studies used in the determination of utility rate base.

1966 to 1971

United Telephone Company of Pennsylvania (now Sprint/United Telephone Company of Pa.). As a staff member of the Plant Accounting Department, his duties and responsibilities included various plant accounting ledgers, unitization of location and mass property accounts, as well as special studies related to insurance and tax valuations of utility plant in service.

TESTIMONY

Jurisdictions testified in include Alberta, Arizona, California, Connecticut, Delaware, District of Columbia, FERC, Florida, Indiana, Illinois, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Montana, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Oklahoma, Nevada, Pennsylvania, Rhode Island, South Carolina, Tennessee, Utah, and Virgin Islands. Extensive expert testimony has been presented on the subjects including Depreciation, Capital Recovery, Plant in Service Measures of Value, Depreciated Reproduction Cost, and Depreciated Replacement Cost. Numerous additional depreciation studies have been completed and filed in various different jurisdictions for which testimony appearances were not required.

PERSONAL

Education:

Graduate of Harrisburg Area Community College with an Associate of Arts Degree in Accounting, and has undertaken further studies at University Center of Harrisburg. Successfully completed numerous

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

programs related to service life and salvage estimation, forecasting, and evaluation sponsored by Depreciation Programs, Inc. at Calvin College Campus, Grand Rapids, Michigan. In addition, Mr. Robinson successfully completed cost of service seminars sponsored by the American Water Works Association. He received his CDP (Certified Depreciation Professional) designation by Exam during 1996.

List of Clients Served

CATV

Storer Broadcasting Company
(DE, MD, MN)

Cable Television Consortium

ELECTRIC

Atlantic City Electric d/b/a Conectiv Power Delivery
Borough of Butler - Electric Dept.
Conectiv Power Delivery
Consolidated Edison Co of NY
Consolidated Hydro, Inc.
Delmarva Power and Light Company
Delaware
Maryland
Duquesne Light Company
Hershey Electric Company
Kentucky Utilities
Lockhart Power Company
Louisville Gas & Electric Co. - Elec. Div.
Montana – Dakota Utilities Co – Elec. Div
Nantahala Power and Light Company
New York State Electric and Gas Corp
Northern Indiana Public Service Co
Pennsylvania Power Company
Philadelphia Electric Company
Potomac Electric Power Company
Maryland
Washington DC
Progress Energy - Carolinas
Progress Energy - Florida, Inc
Public Service Company of New Mexico
Public Service Electric & Gas Company
Rochester Gas and Electric Corporation
Wellsboro Electric Company
Vermont Electric Power, Inc

GAS

ATCO Gas
ATCO Pipelines
Atlanta Gas Light Company
Bay State Gas Company
C & T Enterprises, Inc.
Valley Cities Waverly Gas Company
Canadian Western Natural
Gas Company Limited
Cascade Natural Gas Corporation
Citizens Gas & Coke Utility
Columbia Gas of Pennsylvania, Inc.
Connecticut Natural Gas Corporation
Consolidated Edison Co of New York
East Ohio Gas
Elkton Gas Service
Granite State Gas Transmission, Inc.
Great Plains Natural Gas Co.
Kansas Gas Service
North Carolina Gas Service
North Penn Gas
Northern Indiana Public Service Co.
Northern Utilities, Inc.-Maine
Northern Utilities, Inc.-New Hampshire
Oklahoma Natural Gas Company
Pacific Gas & Electric Company
Paiute Pipeline
Pennsylvania Gas & Water Company
PG Energy Inc.
Pennsylvania and Southern Gas Company
Valley Cities Division
Waverly Division
Pipeline Industry Group
Providence Gas Company
Public Service Electric & Gas Co
Public Service Company of New Mexico
Roanoke Gas Company

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS - UTILITY SERVICES
WEBER FICK & WILSON DIVISION

Louisville Gas & Electric Co. - Gas Division
Montana Dakota Utilities - Gas Division
National Fuel Gas Distr. Corp., NY
National Fuel Gas Supply
New York State Electric & Gas Corp
NICOR Gas Company
Northeast Heat & Light Company
Rochester Gas and Electric Corporation
Saxonburg Heat & Light Company
Sierra Pacific Power Co/NV Energy
Southern Connecticut Gas Company
Southwest Gas Corporation
T.W. Phillips Gas & Oil Company
Williams Companies

GENERAL CLIENTS

Arthur Andersen
Pricewaterhouse Coopers
Electric Utility Consultants, Inc.
Ernst & Young
Standard & Poors

REGULATORY AND GOVERNMENTAL

Regulatory Commission of Alaska
- Alaska Electric Light & Power Company
- Interior Telephone Company, Inc
- Fairbanks Water & Wastewater
- Mukluk Telephone Company, Inc
- TDX North Slope Generating
- United KUC, Inc
- United Utilities, Inc.

Arizona Corporation Commission
- Mountain States Telephone & Telegraph
- Southwest Gas Corporation

Baltimore County, MD
Bensalem Township - Water
Bethlehem Authority - Water
Borough of Butler, NJ
Borough of Media Water Works
City of New Orleans, LA
Delaware Public Service Commission
Delaware River Port Authority
Diamond State Telephone Company
Kansas Corporation Commission
- Southwest Bell

Public Service Comm. of Nevada
- Nevada Bell

Town of Waterford, CT
- Northeast Utilities

Washington, D.C. - PSC
- C&P Telephone Company
- Potomac Electric Power Company

TELECOMMUNICATIONS

Ace Telephone Association - IA & MN
Air Touch Communications
ALLTEL Pennsylvania, Inc.
AT&T-Advance Solutions, Inc-CA
BellSouth Telecommunications
Buffalo Valley Telephone Company
Paging Industry Study Group
- AirTouch Paging
- Mobile Comm

Paging Network, Inc.
- Skytel
- USA Mobile Communications

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS - UTILITY SERVICES
WEBER FICK & WILSON DIVISION

Cellular Industry Study Group
- AT&T Wireless

BellSouth Communications
- GTE Mobilnet

Brighthouse Networks-Citrus County
Cable & Wireless
Chenango & Unadilla Telephone Company
Cingular Wireless
- Cingular Wireless – California
- Cingular Wireless – Houston
- Cingular Wireless - Massachusetts

Commonwealth Telephone Company
CTC of Michigan
CTC of Virginia
Denver & Ephrata Telephone & Telegraph Co.
- D & E Network
- D & E System

Embarq Florida, Inc.
Empire Telephone Corporation
Illinois Consolidated Telephone Co.
Jamestown Telephone Corporation
Leesport Telephone Company
Lewisberry Telephone Company
Los Angeles Cellular Telephone Co.
MCI International, Inc.
MCI Telecommunications Corp.
MFS Communication Company, Inc.
Marianna & Scenery Hill Tel. Co.
Mid State Telephone Company
Motorola, Inc.
Nevada Bell
New Jersey Telephone Company
The North-Eastern Pennsylvania Tel. Co.
Pacific Bell
Pactel Cellular
Quaker State Telephone Company
Qwest Communications Corporation
- Qwest – Arizona
- Qwest – Iowa
- Qwest -- Montana
- Qwest -- Washington

RCA Global Communications, Inc.
SBC Ameritech Corporation
- SBC -- Arkansas
- SBC -- Kansas
- SBC -- Michigan
- SBC -- Missouri
- SBC -- Ohio
- SBC -- Oklahoma
- SBC – Wisconsin
- SBC – West – California
- SBC – West – Nevada

Southwestern Bell Telephone Company
Standard Telephone Company
Telecommunications d'Haiti
Telephone Utilities of Pennsylvania
United Telephone Company of New Jersey
Verizon Wireless
- Verizon – California
- Verizon – Kentucky
- Verizon – Massachusetts
- Verizon -- Montana
- Verizon – South Carolina
- Verizon -- Utah
- Verizon -- Washington
- Verizon – Wyoming
- Verizon – Total Company

Virgin Islands Telephone Corporation
Williams Communication
WilTel, Inc.

<u>WATER</u>

Arizona Water Company
Artesian Water Company
City of Auburn
Bethlehem Authority – Water
California Water Service Company
California-American Water Company
- Citizens Water – California
- Citizens Water – Arizona

Clinton Water Company
Columbia Water Company
Commonwealth Water Company
Consumers New Jersey Water Company
Dauphin Consolidated Water Supply Co.
Monarch Utilities, Inc.
Monmouth Consolidated Water Company
New Haven Water Company
New Jersey Water Company
New Mexico-American Water Company, Inc.
Newtown Artesian Water Company
New York-American Water Company
Ohio-American Water Company
Palm Coast Utility Corporation
Pennichuck East Utility
Pennichuck Water Works
Pennsylvania-American Water Company
Pennsylvania Gas & Water Company

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Dominguez Water Company
Elizabethville Water Company
City of Fairfax
Garden State Water Company
Hackensack Water Company
Hawaii Water Service
  Ka'anapali Water
  Kona Water
  Waikoloa Village Water
  Waikoloa Resort Water
  Waikoloa Resort Irrigation
Hershey Water Company
Illinois-American Water Company
Indian Rock Water Company
Indianapolis Water Company
Iowa-American Water Company
Keystone Water Company
Manufacturers Water Company
Masury Water Company
Middlesex Water Company
Monarch Utilities, Inc.
Pennsylvania Water Company
  Erie & Sayre Divisions
Philadelphia Suburban Water Company
Pinelands Water Company
Public Service Water Company
Riverton Consolidated Water Company
Roaring Creek Water Company
Rock Springs Water Company
Shenango Valley Water Company
Southern California Water Company
Spring Valley Water Company
Spring Valley Water Company
Tidewater Utilities, Inc.
United Water - Delaware
United Water - Toms River
United Water - New Jersey
United Water - Pennsylvania
United Water - Virginia
Virginia American Water Company
Western Pennsylvania Water Company
York Water Company

STEAM

Consolidated Edison Co of New York

WASTEWATER

California - American Water Company
 Citizens Sewer – Arizona
Hawaii Water Service Company-Wastewater
  Kona Wastewater
  Pukalani Wastewater Company
  Wailoloa Resort Wastewater
Illinois-American Company – Wastewater
Monarch Utilities, Inc.
New Jersey Water Company
  Sewer Districts
Palm Coast Utility Corporation
Pinelands Sewer Company
Wynnewood Sewer Company

PROFESSIONAL QUALIFICATIONS

CDP (Certified Depreciation Professional) by Exam during October, 1996

PROFESSIONAL AFFILIATIONS

American Water Works Association
American Gas Association
American Railway Engineering Association
Pennsylvania Gas Association
Pennsylvania Municipal Authorities Association
Member AGA Accounting Services Committee
Society of Depreciation Professionals-Founding Member, Chairman Coordinating and Membership Committees, Treasurer, President, and Past President

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS - UTILITY SERVICES
WEBER FICK & WILSON DIVISION

PUBLICATIONS

AGA/EEI Depreciation Accounting Committee, Contributing Author 1989, "An Introduction to Net Salvage of Public Utility Plant"

"Replacement Cost and Service Life Studies", *Journal of Property Tax Management*, Fall 1994, Volume 6, Issue 2

SPEECHES AND PRESENTATIONS

"Depreciated Replacement Cost", Institute of Property Taxation - 18th Annual Conference, San Francisco, CA

"RCNLD Issues for Utilities", The National Association of Railroad & Public Utilities Tax Representative, 1997 Annual Conference, North Lake Tahoe, NV

"Useful Service Lives of Cellular Industry Assets", State of Florida, Department of Revenue, Industry/Government Task Force (April 1997)

"Appraisal and Valuation Issues Associated with Technology Changes within the Wireless Industry", 30th Annual Wichita Program - Appraisal for Ad Valorem Taxation of Communications, Energy, and Transportation Program, Wichita State University - July 30-August 3, 2000

"Physical/Functional Obsolescence, Residual Values/Floors (Net Salvage)", 32th Annual Wichita Program - Appraisal for Ad Valorem Taxation of Communications, Energy, and Transportation Program Wichita State University - July 28-August 1, 2002

"Depreciation Study Preparation", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Lake Tahoe, Nevada - October 28, 2002

"Use of Replacement Cost to Value High Tech Equipment" Southeastern Association of Tax Administrators, 53rd. Annual Conference, Savannah, Georgia - July 14-July 16, 2003

"Property Tax: Use of Replacement Cost in the Appraisal of Telecommunications Companies", Western States Association of Tax Representatives (WSATR), WSATA 2003 Annual Meeting, Austin, TX - Sept. 9, 2003

"Replacement Cost & Depreciated Replacement Cost Presentation", Southwestern Bell Telephone Company – Arkansas PSC – Tax Division - August, 2003

"Valuation of Assets", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Scottsdale, Arizona - December 9, 2003

"Property Tax: Use of Replacement Cost in the Appraisal of Telecommunications Companies", Oklahoma State Board of Equalization Public Service Valuation Guidelines Subcommittee – Oklahoma City, OK – Feb 5, 2004

"Net Salvage Issues In Rate Cases", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, San Antonio, Texas - May 17, 2004

"Current Depreciation Issues: Point-Counterpoint", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Savannah, Georgia – November 14, 2006

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS - UTILITY SERVICES
WEBER FICK & WILSON DIVISION

"Depreciation & Cost of Removal", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Tucson, Arizona – October 24, 2007

"Whole Life versus Remaining Life", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, San Francisco, California – May 21, 2008

*"Obsolescence-Measuring the Impact for Industries Experiencing Change"*_*"Depreciation & Cost of Removal"*, IPT 32nd Annual Conference, Atlanta, Georgia, June 23, 2008

"An Alternative to IFRS Unit Depreciation", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Baltimore, Maryland – May 18, 2009

"Alternative to IFRS Unit Depreciation", Society of Depreciation Professionals, Albuquerque, New Mexico, – October 5, 2009

"Depreciation Training", Regulatory Commission of Alaska (RCA), Anchorage, Alaska, October 26 & 28, 2010

"Physical Depreciation – The Uses and Abuses of Iowa Curves and Other Errors", IPT Property Tax Symposium, Austin, Texas, November 2, 2010

"Preparing To Be A Depreciation Witness", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, New Orleans, Louisiana – May 19, 2011

"Depreciation – The Last 25 Years & More", Society of Depreciation Professionals, Atlanta, Georgia, – September 20, 2011

"A Roadmap to Replacement Cost", 42nd Annual Wichita Program - Appraisal for Ad Valorem Taxation of Communications, Energy, and Transportation Program, Wichita State University - July 29-August 2, 2012

DEPRECIATION TRAINING INSTRUCTOR-CLASSES

Regulatory Commission of Alaska, Anchorage, AK, Oct 2012

EUCI Depreciation Training, Houston, TX, Nov 8-9, 2012

EUCI Depreciation Training, Denver, CO, May 6-7, 2013

EUCI Depreciation Training, Chicago, IL, Nov 14-15, 2013

EUCI Depreciation Training, Pasadena, CA, Apr 22-23, 2014

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

SUMMARY OF TESTIMONY APPEARANCES – HEARINGS & DEPOSITIONS (PLUS DECLARATIONS)

Jurisdiction	Client	Docket/Application	Subject
Alberta	Canadian Western Natural Gas Company Limited	980413	Depreciation
	ATCO Pipelines	1292783 Appl. 1527976, Proc ID 13	Depreciation Depreciation
Arizona	Arizona Corp. Comm./ Mtn. Bell	9981-E-1051	RCN/RCND *
	Arizona Corp. Comm./ Southwest Gas Corp.	U-1551-80-70	RCN/RCND *
	Qwest Corporation-Arizona	TX2001-000662	Property Tax Valuation Deposition
California (PUC & State Board of Equalization)	MCI Telecommunications Corporation	274	Replacement Cost/ Depr. Repl. Cost
		SAU87-38	Replacement Cost/ Depr. Repl. Cost
		SAU91-101	Replacement Cost/ Depr. Repl. Cost
	SBC-California	SAU 279 Declaration	Property Tax Valuation
	SBC-California	January 31, 2005 Declaration	Property Tax Valuation
	Southern California Water Company	ABJ-4	Depreciation
Connecticut	Connecticut Natural Gas Corp	08-12-06 13-06-08	Depreciation Depreciation
	Southern Connecticut Gas Co.	89-09-06	P.I.S. Measures of Value and Depreciation
		08-12-07	Depreciation
Delaware	Artesian Water Company	82-20 87-3	Depreciation Depreciation
	United Water - Delaware	96-164 98-98	Depreciation Depreciation
	Delaware Public Service Comm./ Diamond State Telephone Co.	81-8	P.I.S. Measures of Value and Depreciation
	Delmarva Power & Light Company	05-304	Depreciation

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Jurisdiction	Client	Docket/Application	Subject
	Tidewater Utilities, Inc/ Public Water and Supply, Inc	99-466	Depreciation
District of Columbia	Potomac Electric Power Co.	F.C. 869	Depreciation
	Washington, DC PSC/C&P Tel Corp.	F.C. 777	Depreciation
	Washington, DC PSC/ Potomac Electric Power Co.	F.C. 785 F.C. 813	Capital Recovery/ Depreciation
FERC	Granite State Gas Transmission, Inc.	RP91-164-000	Depreciation
	Paiute Pipeline	RP96-306-000	Depreciation
	Public Service Company of NM	ER-11-1915-000	Depreciation
Florida (County of Duval)	BellSouth Telecommunications	Petitions 1795-1800	Replacement Cost/ Depr. Repl. Cos
(County of Lee)	Sprint-Florida, Inc (Embarq)	Case No. 02-CA-013330-1	Replacement Cost
(County of St. Lucie)	BellSouth Telecommunications	1999 Petitions	Replacement Cost/ Depr. Repl. Cost
(County of Citrus)	Embarq	Case No. 2003-CA4473, 2004-CA4565, 2005-CA5010	Property Tax Valuation Deposition
(County of Lee)	Embarq	Case No. 02-13330 CA-WCM	Property Tax Valuation Deposition
	Progress Energy – Florida Progress Energy – Florida	050078-EI 090079-EI	Depreciation Depreciation
Illinois	Illinois - American Water Company	00-0340 02-0690 07-0507	Depreciation Depreciation Depreciation
	Illinois Consolidated Telephone Co.	81-0264 82-0623	RCN/RCND * RCN/RCND *
Indiana	Northern Indiana Public Service Company	Cause No. 41746	Depreciation
Iowa (Dept of Rev)	Qwest Corporation-Iowa	883	Property Tax Valuation Deposition

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS - UTILITY SERVICES

Jurisdiction	Client	Docket/Application	Subject
Kansas	Kansas Gas Service	03-KGSG-602-RTS	Depreciation
Kentucky	Kentucky Utilities	Case No. 2003-00434	Depreciation
	Louisville Gas & Electric Electric Gas	Case No. 2003-00433	Depreciation
Maryland	Delmarva Power & Light Company	9093	Depreciation
	Potomac Electric Power Company	9092	Depreciation
Massachusetts	Bay State Gas Company	92-111 DTE 05-27	Depreciation Depreciation
Montana	Montana-Dakota Utilities Co-Gas	Docket #2012.9.100	Depreciation
	Montana-Dakota Utilities Co-Elec	Docket # 2007.7.79 Docket # 2010.8.82	Depreciation Depreciation
	Qwest Corporation-Montana	06DORFC001 06DOTFC017	Property Tax Valuation Deposition
Nevada	Southwest Gas Corporation	04-3011	Depreciation
New Jersey	Atlantic City Electric d/b/a Conectiv Power Delivery	ER03020110	Depreciation
	Borough of Butler/ Butler Elec. Dept.	792-84	Valuation of Plant in Service Customer Revenue and Purchase Power
	Commonwealth Water Co.	842-100	Depreciation
	Consumers NJ Water Company	WR00030174	Depreciation
	Garden State Water Co.	WR91091483	Depreciation
	Middlesex Water Company	WR8602-240 WR90080884J WR96110818	Depreciation Depreciation Depreciation
	Monmouth Cons. Water Co.	8312-1113	Depreciation
	New Jersey Water Company	834-292	Depreciation
	Public Service Electric & Gas	GR05100845	Depreciation
	United Water Resources	8506-663	Depreciation

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Jurisdiction	Client	Docket/Application	Subject
	(formerly Hackensack Water Co.)	WR90080792J WR95070303	Depreciation Depreciation
	Toms River Water Company	WR95050219	Depreciation
New Hampshire	Northern Utilities, Inc.	DR91-081	Depreciation
New Mexico	New-Mexico American Water Company, Inc.	2813 03-00206-UT	Depreciation Depreciation
	Public Service Company of NM	08-00273-UT 10-00086-UT	Depreciation Depreciation
New York	New York-American Water Co.	28911	Depreciation
	New York State Elec. & Gas Corp. Electric Business & Common Plant	05-E-1222	Depreciation
	New York State Elec. & Gas Corp-Elec.	09-E-0715	Depreciation
	New York State Elec. & Gas Corp-Gas	09-G-0716	Depreciation
	Rochester Gas and Elec. Corp-Elec.	09-E-0717	Depreciation
	Rochester Gas and Elec. Corp-Gas	09-G-0718	Depreciation
	Spring Valley Water Co., Inc.	89-W-1151 92-W-0645	Depreciation Depreciation
North Carolina	Nantahala Power and Light Co.	E-13, SUB157	Depreciation
North Dakota	Montana-Dakota Utilities Co-Gas	Case No. PU-399-02-183	Depreciation
Oklahoma (State Board of Equalization)	SWBT-Oklahoma	EQ-2004-10	Property Tax Valuation Deposition
Pennsylvania	Borough of Media Water Works	R-912150	Depreciation
	Columbia Gas of Penna.	R-80031129	Depreciation and Valuation
	Commonwealth Telephone Co.	I-00920020	Depreciation
	Keystone Water Company	R-842755 R-842756 R-842759	Capital Recovery/Depreciation Capital Recovery/Depreciation Capital Recovery/Depreciation
	Mid Penn Tel. Corp.	R-80071264	Depreciation
	Penna.-American Water Co.	R-891208	Depreciation

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Jurisdiction	Client	Docket/Application	Subject
	Penna. Gas & Water Co. - Gas Division	R-821961	Depreciation
		R-832475	Depreciation
	Penna. Gas & Water Co. - Water Division	R-822102	Depreciation
		R-850178	Capital Recovery/Depreciation
		R-870853	Capital Recovery/Depreciation
	Penna. Gas & Water Co. - Scranton Division	R-901726	PIS Meas. of Value/Depreciation
		R-922482	Depreciation
	Penna. Gas & Water Co. - Spring Brook Division Nesbitt Service Area	R-911966	PIS Meas. of Value/Depreciation
	Crystal Lake Service Area	R-922404	PIS Meas. of Value/Depreciation
	Cease town/Watres Service Area	R-93266	Depreciation
	Penna. Power Company	R-811510	PIS Meas. of Value/Depreciation
		R-821918	PIS Meas. of Value/Depreciation
		R-832409	PIS Meas. of Value/Depreciation
		R-842740	PIS Meas. of Value/Depreciation
		R-850267	PIS Meas. of Value/Depreciation
		R-870732	PIS Meas. of Value/Depreciation
	Pennsylvania & Southern Gas Company	R-870686	Depreciation
	PG Energy Inc.	R-963612	PIS Meas. Of Value/Depr
		R-984280	PIS Meas. Of Value/Depr
		R-00061365	PIS Meas. OFValue/Depr
	Philadelphia Suburban Water Company	R-911892	Depreciation
		R-922476	PIS Meas. of Value/Depreciation
		R-932868	PIS Meas. of Value/Depreciation
	Riverton Consolidated Water Co.	R-842675	Capital Recovery/Depreciation
	United Water - Pennsylvania	R-00973947	Depreciation
	Western Pennsylvania Water Company	R-842621	Capital Recovery/Depreciation
		R-842622	Capital Recovery/Depreciation

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Jurisdiction	Client	Docket/Application	Subject
		R-842623	Capital Recovery/Depreciation
		R-842624	Capital Recovery/Depreciation
		R-842625	Capital Recovery/Depreciation
	Wellsboro Electric Company	R-00016356	Depreciation
Rhode Island	Providence Gas Company	1914	Depreciation
		2286	Depreciation
South Carolina	Lockhart Power Company	87-435-E	Depreciation
Tennessee (Board of Equalization)	Bellsouth – Tennessee	67-5-903	Property Tax Valuation Deposition
Utah	Verizon Wireless	05-0826, 05-0829	Property Tax Valuation Deposition & Hearing
Virgin Islands	Virgin Islands Tel. Corp.	264	Depreciation
		314	Depreciation
		316	Depreciation

* Reproduction Cost New/Reproduction Cost New Depreciated.

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2015.6.__

Direct Testimony
of
Travis R. Jacobson

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

2 A. Yes. My name is Travis R. Jacobson and my business address is

3 400 North Fourth Street, Bismarck, North Dakota 58501.

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

5 A. I am the Regulatory Analysis Manager for Montana-Dakota Utilities

6 Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

7 Q. **Would you please describe your duties as Regulatory Analysis**

8 **Manager?**

9 A. I am responsible for the preparation of cost of service studies, fuel

10 cost adjustments, purchased gas cost adjustments and gas tracking

11 adjustments in each of the jurisdictions in which Montana-Dakota

12 operates.

13 Q. **Would you please describe your education and professional**

14 **background?**

15 A. I graduated from Minot State University with a Bachelor of Science

16 degree in Accounting and I am a Certified Public Accountant (CPA). I

17 started my career with Montana-Dakota in 1999 as a financial analyst in

1 the Financial Reporting area and during my tenure with the Company
2 have held positions of increasing responsibility, including Supervisor,
3 Financial Reporting & Planning and Manager, Financial Reporting &
4 Planning before attaining my current position.

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

6 A. Yes. I have previously presented testimony before this
7 Commission as well as the Wyoming Public Service Commission.

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

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

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

14 A. The purpose of my testimony is to present the per books cost of
15 service for the twelve months ended December 31, 2014, the pro forma
16 cost of service reflecting known and measurable adjustments that will
17 occur by December 2015, the pro forma cost of service supporting the
18 request for interim rate relief and the calculation of the interim and final
19 revenue deficiencies.

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

21 A. I am sponsoring the Overall Cost of Service, Statements C through
22 E, Statement G, Statement H, pages 1 -2 and 6 - 7, Statements I through
23 K and Part A of Statement O. Also, the Interim Statements C through E,

Statements G, Statement H, pages 1-4, I through K, Statement O and Exhibit No.___(TRJ-1), the calculation of the final revenue requirement, Exhibit No. ___ (TRJ-2), the fuel and purchase power cost (fuel and power supply) adjustment tariff, Exhibit No. ___(TRJ-3), the under recovered balance of the MCC/PSC tax, and Exhibit No. ___ (TRJ-4), the calculation of the interim revenue requirement.

Pro Forma Revenue Requirement

Q. What were the results of Montana electric operations for the twelve months ended December 31, 2014?

A. Rule 38.5.175, pages 1 and 2 show the per books income statement and rate base for total Company and Montana. As shown on page 1, Montana electric operations had a return on rate base of 8.256 percent for the twelve months ended December 31, 2014. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the applicable Statement or rule listed. Pages 3 through 5 list the pro forma adjustments to operating revenues, expenses and rate base. All adjustments were calculated on either a Montana specific basis or on a total Company basis and allocated to Montana, as indicated on the statement or schedule detailing each adjustment.

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

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense and rate base to the jurisdictions as part of the regular accounting process on a

monthly basis. The allocation methods and procedures are the same as have previously been used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

Q. What criteria were used to determine the pro forma adjustments?

A. The pro forma adjustments to operating revenue, expenses and rate base were based on known and measurable changes occurring by December 31, 2015, conform to past Commission practices and are listed on pages 3 through 5 of Rule 38.5.175. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

Q. Would you describe the pro forma adjustments to the income statement and rate base?

A. Yes. The adjustments to the income statement are summarized on Rule 38.5.175, page 3 and 4 and consist of adjustments to revenue, operation and maintenance expenses, depreciation expense, taxes other, and current and deferred income taxes. The adjustments to rate base are summarized on page 5 and include plant, accumulated reserve and associated additions and deductions. Each adjustment is discussed in detail below.

<u>Pro Forma Income Statement</u>

Q. What adjustments were made to operating revenues?

A. The adjustments to operating revenues are contained in Rule 38.5.164, Statement H. Adjustment No. 1 is the adjustment to reflect pro

1 forma sales revenues as discussed by Ms. Tamie A. Aberle and is an
2 increase in revenue of $150,374.
3 Adjustment No. 2 decreases revenue by $232,169 to reflect the
4 elimination of sales for resale of $178,885 as well as the revenue received
5 under the margin sharing provision of $53,284. Pursuant to the Stipulation
6 in Docket No. D2010.8.82, the sales for resale margin level to be used in
7 the adjustment mechanism was set at $101,000 with 90% of any under
8 recovery collected from the customer. Montana-Dakota has not achieved
9 that level of resale margin since its implementation in September 2011.
10 During 2015, no sales for resale have occurred through May and 2014
11 reflected a total margin of only $41,795. Therefore, the Company is
12 proposing to remove the resale margin included in base rates and is
13 eliminating the wholesale sales revenues. Should sales for resale occur in
14 the future, the Company is proposing to credit 85 percent of total
15 wholesale sales margins through the Fuel and Purchased Power (fuel and
16 power supply) tracking adjustment. As such, the pro forma amount for the
17 wholesale sales margin embedded within the calculation of the revenue
18 requirement is zero.
19 Adjustment No. 3 includes the adjustments to other operating
20 revenues. Basin Electric Power Cooperative (BEPC) is joining the
21 Southwest Power Pool (SPP) in 2015 and the revenue received under the
22 joint use facilities agreement will cease at that time. Therefore, joint use
23 revenue was removed on a pro forma basis for a reduction in revenue of

1 $280,236. The pro forma rental income was annualized based on the
2 December 2014 monthly revenue resulting in an increase of $3,667.
3 Montana-Dakota is using a three year average of KVAR penalty as a
4 representative level of KVAR revenue that is included as part of other
5 revenue resulting in a reduction of $10,760. In addition, late payment
6 revenue was increased to reflect the ratio of 2014 late payments to sales
7 revenue applied to pro forma revenue for an increase of $2,662.
8 Gains and losses for the three year period ending December 31,
9 2014 totaled a net loss of $15. No adjustment will be included due to
10 immateriality.
11 Q. **What adjustments were made to operation and maintenance (O&M)**
12 **expenses?**
13 A. The adjustments to operation and maintenance expenses are
14 contained in Rule 38.5.157, Statement G, and are summarized in Rule
15 38.5.156.
16 Fuel and purchased power is shown on Rule 38.5.157, page 5.
17 Fuel and purchased power costs have been restated to the pro forma level
18 to reflect the inclusion of the Thunder Spirit wind facility and the RICE
19 generating unit located at the Lewis & Clark Station site as well as the Big
20 Stone and Lewis & Clark environmental project modifications. The
21 recently added Heskett III combustion turbine located in Mandan, North
22 Dakota has been included for generation as well as supplanting the
23 capacity contract that expired in 2015. Finally, the fuel and purchased

power costs reflect a re-dispatch to reflect normal outage schedules for the all plants and current MISO market costs for energy.

In addition, Montana-Dakota is proposing to recover emissions controls costs necessary to comply with the Federal Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) Rules in the fuel and purchased power adjustment mechanism. The emissions controls costs are associated with use of reagents to control for mercury emissions and is further discussed in the testimony of Alan L. Welte. Reagent expenses will be incurred at Big Stone Station upon completion of its Air Quality Control System (AQCS) project and also be required at the Lewis & Clark Station and the RICE unit, both located near Sidney, Montana as well as the Coyote Station, located near Beulah, North Dakota. Montana-Dakota's other generating facilities do not currently require the use of reagents to comply with the MATS rule. The quantity of reagents at the generating facilities will fluctuate directly in relation to the operation of the facilities, similar to fuel costs. The majority of these charges are new costs to the Company and the incurrence of these costs is necessary to meet newly implemented emissions rules. Montana-Dakota is proposing to reclassify the existing reagent costs from other operation and maintenance expenses. Previously, reagent costs were a component of other O&M costs and this proposed change results in a shift in recovery from O&M to Fuel. Adjustment No. 16 reflects the removal of the reagent from the Other Production O&M.

The overall change in fuel and purchased power is a reduction of $1,809,943, largely reflecting reduced MISO purchases due to Thunder Spirit generation and the expiration of the capacity contract supplanted by the Heskett III combustion turbine. These reductions are partially offset by the inclusion of reagent.

Fuel costs associated with the wholesale sales have been excluded from the pro forma fuel and purchased power costs as Montana-Dakota is proposing to include wholesale sales margin in the fuel and power supply tracking adjustment assuming a zero base.

Q. How were the pro forma labor and benefits developed?

A. The adjustment to labor is Adjustment No. 5. The pro forma labor was developed by applying the percentage increase in total Company labor costs to the actual 2014 Montana labor expense. Pro forma total Company labor costs were based on the application of an increase of 4.0 percent for union employees and 3.5 percent for nonunion employees effective in 2015. In addition, incentive compensation has been adjusted to reflect a three year average percentage of labor. This results in an overall increase in labor of $253,565 or 3.97 percent.

Benefits are shown on page 7 of Statement G. Adjustment No. 6 is an overall increase of $176,006 in benefits. Benefits expense consists of medical/dental insurance, pension expense, post-retirement, 401K, workers compensation, and other benefits (primarily disability insurance).

1 Each of these items was adjusted individually using current information
2 and applying the percentage increase to each type of benefit.
3 Medical and dental expense is increasing 4.1 percent. The
4 increase is based on medical and dental premiums currently in effect
5 during 2015. Pension expense is increasing 136.3 percent reflecting a
6 decrease in the discount rate and lower than expected asset returns. The
7 Company continues to make contributions to the pension fund to minimize
8 expense and maintain adequate pension funding. Post-retirement
9 expense is increasing by 166 percent from 2014 levels. A decrease in the
10 discount rate used in the actuarial study as well as lower than expected
11 asset returns account for this increase in expense as well. 401(k)
12 expense and Other Benefits are increasing consistent with the change in
13 labor costs. Workers compensation expense is based on the ratio of 2014
14 workers compensation expense to 2014 labor expenses.
15 Adjustment No. 7, shown on page 8 of Statement G, reflects
16 incremental employees, as well as the related benefits, necessary to
17 continue to operate and maintain Montana-Dakota's electric production
18 facilities. The Power Production Department is increasing its staff level by
19 four employees in order to meet the increasing environmental regulations
20 as well as assist in the day to day operations of the department.
21 Additional employees are also included for the Glendive Turbine and the
22 Diamond Willow and Cedar Hills wind facilities to alleviate staffing issues
23 at those facilities. All employees have been or will be in place by the end

1 of 2015. Total labor and associated benefits are $199,623 on an annual
2 basis.

3 **Q. Would you describe the other adjustments made to O&M expense?**

4 A. Yes. Adjustment Nos. 8, 9 and 10 are related to production
5 facilities placed in service during 2014 or expected to be placed in service
6 during 2015. The Heskett III combustion turbine was placed in service in
7 August 2014. However, the final phase of the construction process
8 involved a significant level of testing that extended to the end of 2014
9 resulting in the majority of the charges to the facility being covered under
10 the contractor certification process and capitalized as a part of the
11 construction cost. Therefore, Adjustment No. 8 reflects the expected
12 annualized cost of operations for that unit as no per books costs were
13 incurred. Adjustment No. 9 reflects the expenses related to the RICE unit
14 located at the L&C Station site and the Mercury and Air Toxic Standard
15 (MATS) requirements discussed by Mr. Neigum and Mr. Welte.
16 Adjustment No. 10 reflects the annual costs of the Thunder Spirit wind
17 facility including labor and benefits expense associated with two
18 technicians, the maintenance contract and the annual easement
19 payments. The pro forma adjustment amounts for Adjustment No. 8, 9,
20 and 10 are $78,765, $115,857 and $713,516, respectively.

21 Adjustment No. 11 shows the $186,584 reduction in transmission
22 charges related to the joint use (facility charge) agreement between
23 Montana-Dakota and BEPC as the contract expires during 2015.

1 Adjustment No. 12 reflects the increase in transmission charges to replace
2 the previously mentioned facility charge and charges incurred under the
3 current WAPA transmission service agreement with transmission service
4 in the SPP market. This expense is net of revenue credits expected to be
5 provided by SPP. In addition, the transmission charges have been
6 updated to reflect the current tariff under the MISO market. Mr. Neigum's
7 testimony further supports these changes. Also included in this
8 adjustment are ongoing annual maintenance costs of the production
9 facilities which were not performed during 2014, primarily borescope
10 inspections. The borescope inspections have been completed in 2015
11 and will continue to be done on an annual basis. The total increase in
12 subcontract labor is $1,509,341.
13 Adjustment No. 13 reflects the expenses associated with the
14 Company's Big Stone and Coyote generating stations to reflect operations
15 for 2015. The adjustment reflects major overhaul costs for Big Stone
16 station as the Company normally performs major annual overhauls on a
17 rotating basis. No major annual overhauls were scheduled in 2014 and,
18 therefore, the costs are expected to continue on an annual basis in the
19 future and are included in this adjustment.
20 The change to materials (Adjustment No. 14) reflects a reduction in
21 materials as 2014 included large nonrecurring transmission project
22 expenses. The net reduction in materials is $31,069.

Adjustment No. 15 reflects the increase in the per ton cost of sand, from $29.00 to $38.50, as well as the increased usage of sand in the fluidized bed at the Heskett Station in the amount of $39,548. The increased usage is required to combat the increased level of clay received in the coal received at the plant.

As noted previously, Adjustment No. 16 reflects the removal of the reagent from the per books information as the Company is proposing to recover these variable costs in a manner consistent with fuel and purchased power cost recovery as shown in Adjustment No. 4.

Vehicles and work equipment (Adjustment No. 17) reflects all expenses associated with the Company's vehicles and equipment, such as backhoes, including the costs of fuel, insurance, maintenance and depreciation expense. This adjustment reflects an increase in this account due primarily to the change in the depreciation component of the expense and it is calculated based on the pro forma plant and the proposed depreciation rates in Statement I. The depreciation component on these items is not charged to depreciation expense but rather is charged to a clearing account where it is then recorded in O&M expense as the vehicles or work equipment is used.

Communications represents charges for telephone and computer network expenses and shows a reduction of $3,510 as shown in Adjustment No. 18. Expenses are expected to decrease slightly due to

lower telephone and SCADA expense, partially offset by increased cell phone charges.

Company consumption (Adjustment No. 19) is the expense for electric and natural gas consumption in Company buildings. The electric component is projected to increase in step with the projected revenue increase for an increase of $10,998. The natural gas component is expected to decrease $4,444 based on the decrease in normalized firm sales and average 2014 gas cost.

Postage is adjusted to show the increase in postage rates and is offset to reflect the number of customers utilizing the electronic billing function offered by Montana-Dakota through its recently implemented customer information system. The December 2014 customer count using the electronic billing has been annualized. Adjustment No. 20 is a net increase of $1,999.

Uncollectible accounts expense (Adjustment No. 21) is a decrease of $16,519 from per books based on the three year average of net write-offs to pro forma sales revenues. The percent of write-offs has increased over the last several years. The per books uncollectible accounts expense is presented on a GAAP basis and is determined based on the average aged receivable balance outstanding as of December 31, 2014 accounting for the slightly higher expense level than net write offs.

Advertising expense (Adjustment No. 22) is shown on page 23. Pursuant to past Commission policy, general promotional and all

1 institutional advertising expense that was not related to Montana electric
2 operations has been eliminated. Informational advertising is adjusted to
3 exclude advertising not directly applicable to Montana electric operations.
4 Insurance expense (Adjustment No. 23) reflects the expense at
5 current levels for 2015 and represents an increase of $74,530. Insurance
6 expense was adjusted to reflect current levels and self-insurance expense
7 was adjusted to reflect a five year average of claims and related expenses
8 incurred.
9 Adjustment No. 24, software maintenance, reflects an increase in
10 software expenses and maintenance contracts as well as implementation
11 of new systems for an increase of $9,074.
12 Industry dues (Adjustment No. 25) reflects the pro forma level of
13 industry dues and is a decrease of $4,884. Rule 38.5.157, Statement G,
14 page 26 shows those dues that are directly assigned or allocated to
15 Montana and appropriately included in the pro forma expense level. In
16 compliance with past orders, 40 percent of dues to the local Chambers of
17 Commerce are excluded.
18 Rent expense was updated to reflect an additional office lease for
19 General Office operations entered into in late 2014 as well as a reduction
20 of annual rent related to the purchase of land in Miles City. Adjustment
21 No. 26 is a net increase of $4,429.
22 Annual easements were reduced to reflect the payment of both the
23 2013 and 2014 Cedar Hills and Diamond Willow wind facilities annual

1 lease payments which were expensed in 2014. The reduction of $31,855
2 in Adjustment No. 27 reflects annual expenses equivalent to one year's
3 lease expense.
4 Regulatory Commission Expense (Adjustment No. 28) reflects the
5 expenses to be incurred in this filing, amortized over a three-year period,
6 and a three year average of ongoing regulatory commission expenses.
7 The adjustment is an increase of $85,473.
8 Adjustment No. 29 reflects a three-year average of the regional
9 market expense assessed by MISO with an increase of $9,434.
10 The items adjusted individually above represent approximately 98
11 percent of total Montana electric O&M, as shown on page 31. The
12 remaining items, which make up approximately 2 percent of other O&M,
13 are assumed to remain flat.
14 **Q. What adjustments were made to depreciation expense?**
15 A. The adjustment to depreciation expense is contained in Rule
16 38.5.165, Statement I. Adjustment No. 30 restates annual depreciation
17 expense to the average pro forma level of plant in service with proposed
18 depreciation rates from a 2014 study prepared by AUS Consultants and
19 further discuss by Mr. Robinson. The depreciation rates are shown on
20 Statement I, pages 3 through 7.
21 In addition, Company's is proposing to discontinue the collection of
22 decommissioning costs for its existing power production facilities. The
23 Company has commissioned studies to support the cost to decommission

its existing production fleet and has determined the portion allocated to Montana is less than the accumulative balance recovered from rate payers as of December 31, 2014. The Company is proposing to amortize the over recovered balance over 10 years which will result in a decrease in depreciation expense of $671,219 annually.

The net adjustment to depreciation expense is an increase of $616,848 and reflects the inclusion of plant additions, except as detailed below, annualizing the 2014 ending plant balances, proposed deprecation rates and the return of the over recovered decommissioning costs.

Adjustment No. 31 is the annual depreciation expense for the large generation projects and is shown on page 8. The depreciation rates for Big Stone and Lewis & Clark are consistent with the previously mentioned study and the Thunder Spirit wind farm and the RICE units located at Lewis & Clark Station are based on industry based life estimates.

Q. What adjustments were made to taxes other than income?

A. The adjustments to taxes other than income are contained in Rule 38.5.174, Statement K. Adjustment No. 32 restates ad valorem taxes to the pro forma level of plant in service based on the 2014 ratio of ad valorem taxes to plant. The net result is an increase of $440,487.

The adjustment to payroll taxes (Adjustment No. 33) is an increase of $18,454 based on the ratio of payroll taxes to labor expense for 2014 applied to pro forma labor expense.

The Montana Consumer Counsel Tax and Public Service Commission taxes are restated in Adjustment No. 34 to the pro forma level of revenue and the rate effective October 1, 2014 and results in an increase of $46,227.

Electric production taxes were restated in Adjustment No. 35 to reflect the pro forma load resources included in Adjustment No. 4, including the Thunder Spirit wind facility that is subject to recent North Dakota legislation exempting wind production facilities from property tax and replacing it with production taxes. The net change is an increase of $112,051.

Q. What adjustments were made to income taxes?

A. The adjustments to income taxes are contained in Rule 38.5.169, Statement J. The adjustment to interest expense (Adjustment No. 36) is shown on page 8. Interest is deductible for tax purposes and interest expense is calculated on the pro forma rate base using the weighted cost of debt and debt ratio from Statement F. The resulting interest expense is an increase of $2,134,174 from the per books level.

The adjustment for tax depreciation and deferred taxes on the pro forma plant additions, including the large generation projects (Adjustment No. 37) is shown on page 15.

The current income tax expense on all of the pro forma adjustments to operating revenues and expenses are calculated on page 9 in Adjustment No. 38.

1 The production tax credit (PTC) related to energy produced at the
2 Company's wind generating facilities was adjusted to reflect a credit of 2.3
3 cents per kWh of production for a total increase in the federal income tax
4 credit of $2,550,561. Adjustment No. 39, page 10, is based on the re-
5 dispatch of the existing wind facilities and also includes the Thunder Spirit
6 wind facility based on an expected capacity factor of 45.2 percent. Per
7 books 2014 included the utilization of 2013 PTCs which were offset by
8 lower deferred income taxes resulting in no change in net income tax.
9 The closing/filing and prior period adjustments in the current
10 income tax accrual and in the deferred taxes are eliminated in Adjustment
11 No. 40. Adjusted current and deferred income taxes match those
12 calculated for Montana and conform to past Commission practices.
13 **Pro Forma Rate Base**
14 **Q. How was the rate base developed?**
15 A. The pro forma rate base is based on the average 2014 rate base
16 and reflects known and measurable adjustments that will occur within
17 twelve months beyond December 31, 2014. The resulting rate base is
18 stated on an average basis, except as noted below. The pro forma
19 adjustments to rate base are summarized on Rule 38.5.175, page 5.
20 Adjustment A annualizes the December 31, 2014 ending balance
21 and includes known and measurable plant additions that will be in service
22 by December 31, 2015. The pro forma adjustment of $12,388,623
23 includes additions to production, transmission, distribution, general and

common plant and is shown on Rule 38.5.125, Statement C, pages 2 through 7.

Adjustment B is Montana's allocated portion of the following large generation projects:

- Big Stone AQCS environmental project
- Lewis & Clark MATS environmental project
- RICE Units located at Lewis & Clark Station site
- Thunder Spirit Wind Farm

These production investments total $91,985,818 and have been annualized to reflect the plant additions as if they were in service the entire year and are shown on page 8. Each generation project is discussed in more detail in the testimony of Mr. Welte and Mr. Neigum. All related adjustments were also annualized, including the energy generated and associated fuel and purchased power costs and the related production tax credits associated with wind generation.

Adjustment C, shown in Rule 38.5.133, Statement D, page 2, increases the average reserve for depreciation on the per books plant by $4,217,990 to restate the reserve to the average pro forma level in order to match the average pro forma plant levels.

Adjustment D, shown in Rule 38.5.165, Statement I page 8, shows the increase in the average reserve for depreciation related to the large generation projects in the amount of the annual depreciation of $3,991,229.

The working capital and other additions and deductions are adjusted and included in Rule 38.5.141, Statement E. Materials and supplies are restated to a thirteen-month average balance, with actual balances through January 31, 2015, in Adjustment E, for a decrease of $59,974.

Coal and fuel oil stores are restated to a thirteen-month average balance in Adjustment F and reflect a decrease of $51,222. The pro forma balance reflects actuals through March 31, 2015 with the remaining months of 2015 based on the current 2015 prices.

Prepaid insurance is restated to a thirteen-month average balance in Adjustment G with actual balances through January 31, 2015 and is an increase of $120,008.

The average net unamortized loss on reacquired debt balances and the associated deferred income taxes as of December 31, 2015 is included as Adjustment H.

The unamortized balance of the decommissioning on retired plants as of December 31, 2015 and the associated deferred income taxes is included as Adjustment I and is a reduction of the average balance of $16,984 with the amortization being reflected as an offset to the depreciation expense in Rule 38.5.165, Statement I.

The average net Provision for Pensions and Benefits as of December 31, 2015 and the associated deferred income taxes is included as Adjustment J in conformance with Order 5856b in Docket No.

D95.7.90. The balance reflects scheduled payments in 2015 and is restated to the current Montana electric allocation for a net increase of $491,293.

The average Provision for Injuries and Damages and the associated deferred income taxes as of December 31, 2015 is included as Adjustment K in conformance with Order 5856b in Docket No. D95.7.90. The balance also reflects the current Montana electric allocation

The adjustments to accumulated deferred income taxes are summarized on Rule 38.5.169, Statement J, page 18.

Adjustment L is the increase to deferred taxes necessary to extend the average accumulated deferred tax balance to match the pro forma plant and accumulated reserve balances. The adjustment also includes the deferred taxes associated with the unamortized loss on debt (Adjustment H), decommissioning of retired power plants (Adjustment I), provision for pensions and benefits (Adjustment J), provision for injuries and damages (Adjustment K), along with customer advances (Adjustment N) and the amortization of the full normalization adjustment for 2014 as shown on page 17.

Adjustment M, page 15, shows the deferred tax associated with the large generation projects. The Big Stone and Lewis & Clark environmental projects qualify for accelerated depreciation and expenditures prior to January 1, 2015 qualify for bonus tax depreciation.

1 The increase to deferred income taxes associated with the large
2 generation projects is $6,808,172.
3 Customer advances for construction (Adjustment N) are restated to
4 a thirteen-month average balance at December 31, 2014, updated through
5 March 31, 2015 for refunds related to plant placed in-service prior to
6 January 1, 2015, The net change is a decrease of $458,389 as shown on
7 Rule 38.5.143, Statement E, page 8.
8 These are all of the pro forma adjustments to revenue, expense
9 and rate base.
10 **Q. What does Rule 38.5.190, Statement O show?**
11 A. The charts and graphs contained in Rule 38.5.190, Statement O,
12 Part A are the pictorial exhibits required by Commission rules.
13 **Q. What is the additional revenue requirement calculated on Exhibit**
14 **No.____(TRJ-1)?**
15 A. Exhibit No.____(TRJ-1), which is identical to Rule 38.5.175, page
16 7, shows the calculation of the revenue deficiency of $11,755,544 based
17 on the pro forma operating income and rate base and using the overall
18 rate of return of 7.588 percent from Rule 38.5.146, Statement F, page 1.
19 **Electric Fuel and Purchased Power Adjustment Cost Tracking**
20 **Q. Would you describe the adjustments to the electric fuel and power**
21 **adjustment cost tracking adjustment proposed in this filing?**
22 A. Yes. Montana-Dakota is proposing to incorporate changes in the
23 fuel and power cost tracking adjustment. The first, as discussed earlier, is

1 to eliminate the wholesale sales margin sharing adjustment and instead,
2 credit 85 percent of all wholesale margins as a credit in the fuel and power
3 cost tracking adjustment. The current level of sales for resale margin
4 included in base rates, set at $101,000 pursuant to the Stipulation in
5 Docket No. D2010.8.82, has not been achieved since the implementation
6 in September 2011. In addition, the Company has had no sales for resale
7 on a year-to-date basis through May 2015.
8 For this reason, Montana-Dakota proposes revise the tariff to reflect
9 a zero base in the determination of the rates charged to customers while
10 allowing the customers to receive a share of future sales and at the same
11 time provide an incentive to the Company to maintain its low cost
12 generation as a resource to the MISO market.
13 Montana-Dakota is also proposing to include reagent charges in the
14 fuel and power supply cost tracking adjustment, as discussed earlier. The
15 quantity of reagents at the generating facilities will fluctuate directly in
16 relation to the operation of the facilities, similar to fuel costs. The majority
17 of these charges are new costs to the Company and the incurrence of
18 these costs is necessary to meet newly implemented emissions rules.
19 Montana-Dakota is proposing to reclassify the existing reagent costs from
20 other operation and maintenance expenses. Previously, reagent costs
21 were a component of other O&M costs and this proposed change results
22 in a shift in recovery from O&M to Fuel. Correspondingly, Adjustment No.

16 on Rule 38.5.157, Statement G, page 17 reflects the removal of the reagent from the Other Production O&M.

Exhibit No. ___(TRJ-2) is the proposed Rate 35 and Rate 58 tariffs, also included in Appendix B.

Proposed recovery of deferred MCC and PSC taxes

Q. Montana-Dakota was authorized, in Docket Nos. N2010.11.105 and N2011.10.90, to defer the revenues associated with the change in the Public Commission Service (PSC) Tax rate and the Consumer Counsel Tax (MCC) rate, both over and under recoveries. Is Montana-Dakota proposing to recover (return) this deferred balance?

A. Yes, Montana-Dakota is proposing to recover the deferred PSC and MCC tax for the period beginning October 1, 2010 and utilize the fuel and purchased power cost tracking adjustment mechanism (electric tracker) as the vehicle to recover the deferred amounts.

Effective September 1, 2011, Montana-Dakota's rates included PSC and MCC tax rates of 0.21 percent and 0.03 percent respectively. Each year the rates have been updated effective October 1st. Overall the tax rates have been higher than the level embedded in rates causing Montana-Dakota to under recover its tax costs. As provided in Docket Nos. N2010.11.105, N2011.10.90, N2012.11.117, D2013.10.72, D2013.10.73, D2014.9.84 and D2014.9.85, Montana-Dakota deferred the difference between the PSC and MCC taxes recovered and the actual taxes incurred. Exhibit No. ___(TRJ-3) shows Montana-Dakota's under

1 recovered balance of $399,742 for the period October 2010 through
2 March 2015.
3 The Company proposes to recover the deferred amount from its
4 customers over a one year period on a per kWh basis based on projected
5 sales and to utilize the electric tracker as the most efficient mechanism to
6 recover the cost. Each year the Company will update the recovery rate in
7 conjunction with the annual change in the unreflected fuel cost adjustment
8 in order to recover or return the deferred account balance as of March 31
9 of each year. The adjustment will not be included in the cost of fuel and
10 purchased power, but will simply use the mechanism as the means of
11 recovering the taxes. The estimated initial recovery per Kwh over the
12 annual period to recover the under recovered balance of $399,742 is
13 approximately 0.0500 cents per Kwh.
14 **Interim Revenue Requirement**
15 **Q. Would you please describe the derivation of the interim increase?**
16 A. Yes. The interim increase has been developed in a separate set of
17 Interim Statements pursuant to the Commission's rules regarding interim
18 rate increase requests in general rate proceedings (Administrative Rules
19 of Montana 38.5.505 and 38.5.506).
20 The derivation of the interim request follows the Commission
21 approved methodology and consists of adjustments to revenue, expense
22 and rate base. The interim request is based on the capital structure and
23 debt costs proposed by the Company, including a return on equity of

1 10.00 percent. The pro forma capital structure was used as the overall
2 return last authorized by the Commission in the Settlement in Docket No.
3 D2007.7.79 was 8.576 percent and the Company's proposed overall rate
4 of return in this case is 7.588 percent, which is lower than the currently
5 authorized return. The interim calculation includes many of the same
6 adjustments as included in the determination of the final revenue
7 requirement and the discussion for those adjustments is not repeated.
8 The pro forma adjustments to revenue and expense are listed on Rule
9 38.5.175, pages 3 and 4 and the adjustments to rate base are
10 summarized on page 5.
11 **Q. Would you describe the interim adjustments to operating revenues?**
12 A. The interim adjustments to operating revenues are contained in
13 Rule 38.5.164, Statement H. Adjustment No. 1 is a decrease of $374,040
14 and is based on actual 2014 volumes and current rates reflecting the cost
15 of fuel described below.
16 Adjustment No. 2 decreases revenues by $190,374, to restate the
17 sales for resale margin at the actual level for the twelve months ended
18 December 31, 2014. Fuel and purchased power costs exclude the cost of
19 fuel related to the sales for resale and therefore only the margin is
20 presented in this adjustment.
21 Adjustment No. 3 is a decrease of $285,244. Late payment
22 decreased slightly due to lower sales revenues.

1 **Q. What interim adjustments were made to operation and maintenance**
2 **expenses?**
3 A. The interim adjustments to operation and maintenance expenses
4 are contained in Rule 38.5.157, Statement G, and are summarized in Rule
5 38.5.156.
6 The cost of fuel and purchased power (Adjustment No. 4) is
7 adjusted to reflect current MISO market pricing, normal outage schedules
8 and includes large generation additions, including the Thunder Spirit wind
9 facility and the RICE unit as well as the Heskett III combustion turbine
10 which replaces the capacity contract that expires in 2015. The Company
11 has proposed to recover reagent costs in the fuel and purchased power
12 tracking mechanism on a final basis; however, the interim revenue
13 requirement reflects reagent costs as other O&M and not part of the fuel
14 as proposed on a final basis.
15 **Q. What other interim adjustments were made to O&M expense?**
16 Labor (Adjustment No. 5) shows an increase of $253,565.
17 Benefits (Adjustment No. 6) is an increase of $176,006.
18 Adjustment No. 7 reflects increased labor and benefits to cover
19 existing operations for an increase of $199,623.
20 Adjustment Nos. 8, 9, and 10 reflect the incremental costs related
21 to generation additions or increased costs for environmental projects.
22 The facility charge (Adjustment No. 11) ceases upon BECP
23 membership in SPP and is replaced with transmission service in SPP in

Adjustment No. 12, which also includes the replacement of WAPA service and production facility maintenance not performed in 2014.

Adjustment No. 13 reflects normal operations at Big Stone and Coyote, including an outage at Big Stone.

Materials expense shows a reduction of $31,069 in Adjustment No. 14.

Sand reflects higher price per ton for an increase in production expenses of $39,548 in Adjustment No. 15.

As previously noted, reagent expenses (Adjustment No. 16) have been adjusted to reflect the increase in reagent required to meet the EPA air quality standards as discussed in Adjustment No. 4.

Vehicles and work equipment (Adjustment No. 17) was adjusted based on pro forma plant included in the interim rate base using deprecation rates currently in effect and approved in Docket No. D2010.8.82 and shows an increase of $18,076. It is calculated based on the pro forma plant and the depreciation rates in Statement I. The depreciation expense on these items is not charged to depreciation but rather is charged to a clearing account where it is then recorded as an O&M expense as the vehicles or work equipment is used.

Communications (Adjustment No. 18) is a decrease of $3,510.

Company consumption (Adjustment No. 19) is the expense for electric and natural gas consumption in Company buildings. The electric component is projected to increase 18.9 percent or $9,885 reflecting the

1 interim revenue requirement increase partially offset by lower revenue at
2 current rates. The natural gas component is expected to decrease $4,444
3 based on 2014 average annual gas costs and current rates.
4 Postage is an increase of $1,999 in Adjustment No. 20.
5 Uncollectible accounts expense (Adjustment No. 21) is a decrease
6 of $19,203 from per books expense. This expense is based on a three
7 year average of net write-offs to pro forma sales revenue, including the
8 additional interim revenue requirement.
9 Advertising expense (Adjustment No. 22) is shown on page 23 and
10 is a decrease of 14,367.
11 Insurance expense (Adjustment No. 23) is an increase of $74,530.
12 Software maintenance is also an increase of $9,074 as shown in
13 Adjustment No. 24.
14 Industry dues (Adjustment No. 25) is a decrease of $4,884.
15 Rent expense (Adjustment No. 26) is an increase of $4,429 and
16 annual easements were reduced by $31,855.
17 Regulatory commission expense (Adjustment No. 28) was adjusted
18 to reflect a three year average of rate case expense of ongoing regulatory
19 commission expense which resulted in a decrease of $8,628.
20 Lastly, regional market expense (Adjustment No. 29) is an increase
21 of $9,434.
22 **Q. What interim adjustments were made to depreciation expense?**

1 A. The interim adjustment to depreciation expense is contained in
2 Rule 38.5.165, Statement I. Adjustment No. 30 restates the annual
3 depreciation expense to the annualized 2014 plant in service level.
4 Montana-Dakota is using the currently effective rates as reflected in the
5 Stipulation in Docket No. D2008.8.82 and shown in Statement I, pages 3
6 through 7 to determine the interim depreciation expense level. Page 8
7 shows the annual depreciation on the large generation projects
8 (Adjustment No. 31) in the amount of $3,799,185.
9 **Q. What adjustments were made to taxes other than income?**
10 A. The interim adjustments to taxes other than income are contained
11 in Rule 38.5.174, Statement K. Ad valorem taxes are restated in
12 Adjustment No. 32 to the pro forma interim annualized plant in service.
13 Based on the 2014 ratio of ad valorem taxes to plant, the result is an
14 increase of $339,199.
15 The adjustment to payroll taxes (Adjustment No. 33) is an increase
16 of $18,454.
17 The Montana Consumer Counsel Tax and Public Service
18 Commission taxes are restated in Adjustment No. 34 to the pro forma
19 level of revenue and the rate effective October 1, 2014 and results in an
20 increase of $44,653.
21 Production taxes reflect an increase of $112,051 in Adjustment No.
22 35.
23 **Q. What adjustments were made to income taxes?**

1 A. The interim adjustments to income taxes are contained in Rule
2 38.5.169, Statement J. The adjustment to interest expense (Adjustment
3 No. 36) is shown on page 2. Interest is deductible for tax purposes and
4 interest expense is calculated on the pro forma interim rate base using the
5 weighted cost of debt and debt ratio from Statement F. The resulting
6 interest expense is an increase of $2,003,223 from the per books level.
7 The current income tax expense on all of the interim pro forma
8 adjustments to operating revenues and expenses are calculated on page
9 4 in Adjustment No. 38.
10 Adjustment No. 39 restates the PTC, including Thunder Spirit wind
11 generation, for an increase of $2,550,561.
12 The closing/filing and prior period adjustments in the current
13 income tax accrual and in the deferred taxes are eliminated in Adjustment
14 No. 40.
15 **Q. What interim adjustments were made to rate base?**
16 A. The pro forma interim adjustments to rate base are listed on Rule
17 38.5.175, page 5.
18 Adjustment A, shown in Rule 38.5.125, Statement C, page 1
19 annualizes the December 31, 2014 balance and shows an increase of
20 $7,301,519. This increase includes an increase related to Heskett III
21 combustion turbine placed in service during 2014. Therefore, the average
22 balance increases $5,963,483 when annualizing for that project.

Adjustment B, in the amount of $91,985,818, reflects the inclusion of the large generation projects.

The accumulated reserve is updated for the annualized plant based on current deprecation rates for an increase of $4,046,218 as shown in Adjustment C while Adjustment D reflects the annual depreciation at current rates for the large generation projects for a total increase to reserve of $3,799,185.

Working capital and other additions were adjusted to reflect the following changes:

- Material and Supplies (Adjustment E) decreased $59,974;
- Fuel Stores (Adjustment F) decreased $51,222;
- Prepayments (Adjustment G) increased $120,008;
- Unamortized Loss on Debt (Adjustment H) decreased $98,461;
- Decommissioning of Retired Plants (Adjustment I) increased rate base by $16,984;
- The Provision for Pension and Benefits increased $491,293 as shown in Adjustment J; and
- The Provision for Injuries and Damages (Adjustment K) increased by $50,168.

Adjustment L, shown on Rule 38.5.169, page 8, is the increase to deferred taxes to reflect the December 31, 2014 ending deferred tax balance, including net negative salvage, and the ending deferred tax balance related to customer advances, the amortization of the full

1 normalization balance for 2015 as well as the tax adjustments related to
2 Adjustments H through K. Adjustment M adds $6,883,813 to the
3 accumulated deferred tax balances to reflect the addition of the large
4 generation projects. The total increase to deferred tax is $8,996,710.
5 Customer advances for construction are restated to a thirteen-
6 month average balance, with actual balances through December 31, 2014
7 and is an increase of $47,375 in Adjustment N.
8 These are all of the pro forma adjustments to revenue, expense
9 and rate base related to the interim request.
10 **Q. What does Exhibit No.____(TRJ-4) show?**
11 A. Exhibit No.____(TRJ-4), which is identical to Interim Rule 38.5.175,
12 page 6 shows the calculation of the revenue deficiency of $10,975,511
13 based on the pro forma operating income and rate base and using the
14 overall rate of return of 7.588 percent from Interim Statement F, page 1.
15 **Q. Does this complete your direct testimony?**
16 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$55,604,814	**$11,755,544**	$67,360,358
Sales for Resale	0		0
Other	2,222,284		2,222,284
Total Revenues	57,827,098	11,755,544	69,582,642
Operating Expenses			
Operation and Maintenance			
Cost of Fuel and Purchased Power	20,508,063		20,508,063
Other O&M	19,262,036		19,262,036
Total O&M	39,770,099		39,770,099
Depreciation	11,509,161		11,509,161
Taxes Other Than Income	4,697,522	35,267 2/	4,732,789
Current Income Taxes	(17,369,321)	4,616,324 2/	(12,752,997)
Deferred Income Taxes	13,047,826		13,047,826
Total Expenses	51,655,287	4,651,591	56,306,878
Operating Income	$6,171,811	$7,103,953	$13,275,764
Rate Base	$174,957,348		$174,957,348
Rate of Return	**3.528%**		**7.588%**

1/ See Rule 38.5.175, page 6.
2/ Reflects taxes at 39.3875% after deducting Consumer Counsel tax of 0.1% and PSC tax of 0.2%.

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A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of Montana
Electric Rate Schedule

Volume No. 4
7th Revised Sheet No. 23
Canceling 6th Revised Sheet No. 23

CONTRACT SERVICE Rate 35

AVAILABILITY:

For the Denbury Onshore LLC accounts designated in the Electric Service Agreement dated January 22, 1998, and October 28, 1998.

RATE:

Basic Service Charge:	$145.00 per month
Demand Charge:	
October – May	$10.00 per Kw
June – September	$11.00 per Kw
Energy Charge:	2.136¢ per Kwh
Base Fuel and Purchased Power:	2. 415¢ per Kwh

MINIMUM BILL:

Basic Service Charge plus Demand Charge.

PAYMENT:

Bills will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100 or any amendments or alterations thereto.

ADJUSTMENT CLAUSES:

Bills are subject to the following adjustments as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Environmental Cost Recovery Rider Rate 98
- Transmission Cost Recovery Rider Rate 99

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 50 Kw. Demands will be determined to the nearest one-tenth kilowatt.

Issued: June 24, 2015 **By:** Tamie A. Aberle
Director – Regulatory Affairs

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Electric Rate Schedule

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Canceling 2nd Revised Sheet No. 23.1

CONTRACT SERVICE Rate 35

POWER FACTOR CLAUSE:

Montana-Dakota reserves the right to require Denbury Onshore LLC to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If Denbury Onshore LLC operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

GENERAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by Montana-Dakota under the laws of the state.

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT:

The following sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment for Contact Service Rate 35. It specifies the procedure to be utilized to adjust the rates for electricity sold in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power (b) amortization of the Unreflected Fuel Cost Account and (c) changes in Montana-Dakota's electric wholesale sales margins as allocated to Contract Service Rate 35.

1. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:
   Unless otherwise ordered by the Commission, the effective date of the Fuel and Power Cost Tracking Adjustment and amortization of the Unreflected Fuel Cost Account shall be service rendered on and after January 1 each year.

2. FUEL AND POWER COST TRACKING ADJUSTMENT:
   The Fuel and Power Cost Tracking Adjustment shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base fuel cost shall be 2.415¢ per Kwh as established in the most recent general rate case.

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CONTRACT SERVICE Rate 35

a. The cost of fuel and purchased power shall be calculated separately for Rate 35, and shall be the sum of the following estimated costs for the annual period the adjustment shall be in effect, as allocated to Montana and to Contract Service Rate 35, taking into account applicable line losses:
   1. The cost of fossil and other fuels and reagents as recorded in Account Nos. 501, 502 and 547.
   2. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in wholesale electric energy and capacity markets as recorded in Account 555, less;
   3. The cost of fuel and purchased power recovered from electric wholesale sales.

c. The cost per Kwh for the year is the sum of 2(b) above divided by projected Contract Service Rate 35 sales volumes for the period the adjustment will be in effect.

d. The difference between the base cost of fuel and purchased power and the calculated cost in 2(b) multiplied by ninety (90) percent.

e. Eighty Five (85) percent of wholesale sales margin shall be divided by the projected Contract Service Rate 35 for the period the adjustment will be in effect.

f. The Annual Fuel and Power Cost Tracking Adjustment shall be the sum of 2(d) and 2(e).

3. UNREFLECTED FUEL COST ADJUSTMENT:
   Contract Service Rate 35 shall be subject to an Unreflected Fuel Cost Adjustment to be effective on January of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected Fuel Cost Account calculated by dividing the applicable balance by the estimated Kwh sales for the twelve months following the effective date of the adjustment.

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CONTRACT SERVICE Rate 35

4. UNREFLECTED FUEL COST ACCOUNT:
   a. Items to be included in the Unreflected Fuel Cost Account are:
      1. Amounts under recovered or over recovered for fuel and purchased power each month as calculated in accordance with Subsection 4(b).
      2. Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

   b. The amount to be included in the Unreflected Fuel Cost Account in order to reflect the items specified in Subsection 4(a)(1) and (2) shall be calculated as follows:
      1. Montana-Dakota shall first determine each month the unit cost for that month's fuel and purchased power.
      2. Montana-Dakota shall then subtract from each month's unit cost the cost of fuel and purchased power included in rates for that month.
      3. The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and by the Kwh sold during that month under Contract Service Rate 35. 90 percent of the resulting amounts shall be reflected in an Unreflected Fuel Cost Account for each rate schedule.
      4. Eighty five (85) percent of wholesale margin shall be calculated on a per unit basis as a credit.
      5. The sum of 4(b)3 and 4(b)4 shall be reflected in an Unreflected Fuel Cost Account for Contract Rate 35.
      6. Carrying charges or credits at a rate equal to the overall rate of return established in the most recent general rate case.

   c. Reduction of Amounts in the Unreflected Fuel Cost Account:
      1. The amounts in the Unreflected Fuel Cost Account shall be decreased each month by an amount determined by multiplying the currently effective Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 4) by the Kwh sold during that month under Contract Service Rate 35. The Account shall be increased in the event the adjustment is a negative amount. The amount

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CONTRACT SERVICE Rate 35

amortized shall be applied pro rata between the Unrecovered Fuel Cost Account and the interest balance.

5. TIME AND MANNER OF FILING:
   a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 6 identifying the amount of the adjustment.

   b. Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts.

6. EFFECTIVE ADJUSTMENT:

Effective Date	Current Adjustment ¢ per Kwh	Amount of Change ¢ per Kwh

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State of Montana
Electric Rate Schedule

Volume No. 4
3rd Revised Sheet No. 43
Canceling 2nd Revised Sheet No. 43

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

1. APPLICABILITY:

This rate schedule sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment. It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in the state of Montana, excluding Contract Service Rate 35, in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power (b) amortization of the Unreflected Fuel Cost Account and (c) changes in Montana-Dakota's electric wholesale sales margins as allocated to its Montana electric jurisdiction excluding Contract Service Rate 35.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Power Cost tracking adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Unreflected Fuel Cost Account shall be July 1 of each year.

b. Montana-Dakota shall file an adjustment to reflect changes in its average cost of electric supply only when the amount of change in such adjustment is at least .001 cents per Kwh. The tracking adjustment to be effective July 1 shall be filed each year, regardless of the amount of the change.

3. MINIMUM FILING REQUIREMENTS:

Montana-Dakota's filing to implement the Fuel and Power Cost Tracking Adjustment effective July 1 of each year shall include the following:

a. Fuel and purchased power costs by month by supply source, with annual totals;

b. Generation and purchases (Mwh) by month by supply source, with annual totals;

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FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

c. Total Montana-Dakota sales by major customer class by month with annual totals and;

d. Montana-Dakota sales by major customer class by jurisdiction by month, with annual totals.

4. FUEL AND POWER COST TRACKING ADJUSTMENT:

a. The monthly Fuel and Power Cost Tracking Adjustment shall be calculated separately for primary voltage and secondary service customers and shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base fuel cost shall be 2.551¢ per Kwh for primary service and 2.558¢ per Kwh for secondary service as established in the most recent general rate case.

b. The cost of fuel and purchased power shall be calculated separately for primary service customers and secondary service customers, and shall be the sum of the following costs for the most recent four month period, as allocated to Montana and to the primary and secondary customer classes:

1. The cost of fossil and other fuels and reagents as recorded in Account Nos. 501, 502 and 547.

2. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in wholesale electric energy and capacity markets as recorded in Account 555.

3. Less the cost of fuel and purchased power recovered from electric wholesale sales.

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FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

c. The cost per Kwh for the month is the sum of 4(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes excluding Contract Service Rate 35.

d. The difference between the base cost of fuel and purchased power and the calculated cost in 4(c) is multiplied by ninety (90) percent.

e. Eighty five (85) percent of wholesales margin shall be divided by retail sales volumes for the most recent four month period for primary and secondary service classes excluding Contract Service Rate 35.

f. The Fuel and Power Cost Tracking Adjustment for the month shall be the sum of 4(d) and 4(e).

The applicable Fuel and Power Cost Tracking Adjustment shall be applied to each of Montana-Dakota's rate schedules except Contract Service Rate 35, recognizing differences among customer classes consistent with the cost of fuel and purchased power included in the applicable class sales rate.

5. UNREFLECTED FUEL COST ADJUSTMENT:

All sales rate schedules shall be subject to an Unreflected Fuel Cost Adjustment to be effective on July 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected Fuel Cost Account calculated by dividing the applicable balance by the estimated Kwh sales for the twelve months following the effective date of the adjustment.

6. UNREFLECTED FUEL COST ACCOUNT:

a. Items to be included in the applicable Unreflected Fuel Cost Account, are:

(1) Amounts under recovered or over recovered for fuel and purchased power, as calculated in accordance with Subsection 6(b) each month.

(2) Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

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FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

b. The amount to be included in the Unreflected Fuel Cost Account in order to reflect the items specified in Subsection 6(a) (1) and (2) shall be calculated as follows:

(1) Montana-Dakota shall first determine each month the unit cost for that month's fuel and purchased power.

(2) Montana-Dakota shall then subtract from each month's unit cost the cost of fuel and purchased power included in rates for that month.

(3) The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and by the Kwh sold during that month under each applicable rate schedule.

(4) Eighty five (85) percent of wholesale sales margin shall be calculated on a per unit basis as a credit.

(5) The sum of 6(b)(3) and 6(b)(4) shall be reflected in an Unreflected Fuel Cost Account for each applicable rate schedule.

c. Reduction of Amounts in the Unreflected Fuel Cost Account:

(1) The amounts in the Unreflected Fuel Cost Account shall be decreased each month by an amount determined by multiplying the currently effective Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 6) by the Kwh sold during that month under each applicable rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

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FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

7. TIME AND MANNER OF FILING:

a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 8 identifying the amount of the adjustment.

b. Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts.

8. FUEL AND POWER COST ADJUSTMENT :

	Primary	Secondary
Base Fuel	2.551¢	2.558¢
Fuel and Power Cost Adjustment		
Total FPPA per Kwh		

Issued: June 24, 2015 **By:** Tamie A. Aberle
Director - Regulatory Affairs

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MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION TAX
MONTANA CONSUMER COUNSEL TAX
CALCULATION OF UNDER RECOVERED ELECTRIC UTILITY BALANCE
OCTOBER 2010- MARCH 2015

		Tax Submitted 1/				Tax Recovered 3/		PSC Difference	MCC Difference	Total Difference
Quarter Ending	Revenue	PSC	MCC	Total	Kwh Sales 2/	PSC	MCC	(Over) Under	(Over) Under	(Over) Under
December 2010	$10,992,493	$46,168	$12,092	$58,260						
March 2011	11,968,677	50,268	13,166	63,434						
June	10,882,828	45,708	11,971	57,679						
September	13,866,379	58,239	15,253	73,492	746,250,071	97,013	14,925	103,370	37,557	140,927
December	11,745,912	23,492	14,095	37,587						
March 2012	12,669,385	25,339	15,203	40,542						
June	10,907,106	21,814	13,089	34,903						
September	14,321,226	28,642	17,185	45,827	750,235,260	97,531	15,005	1,756	44,567	46,323
December	12,486,901	28,720	8,741	37,461						
March 2013	13,263,392	30,506	9,284	39,790						
June	11,597,048	26,673	8,118	34,791						
September	14,406,138	33,134	10,084	43,218	769,215,080	99,997	15,384	19,036	20,843	39,879
December	8,975,908	37,699	9,874	47,573	194,469,016	25,281	3,889	12,418	5,985	18,403
March 2014	14,957,646	62,822	16,453	79,275	225,789,351	29,353	4,516	33,469	11,937	45,406
June	12,639,229	53,085	13,903	66,988	184,532,438	23,989	3,691	29,096	10,212	39,308
September	14,736,547	61,893	16,210	78,103	196,893,129	25,596	3,938	36,297	12,272	48,569
December 2014	13,197,744	26,395	13,198	39,593	197,367,140	25,658	3,947	737	9,251	9,988
March 2015	14,645,962	29,292	14,646	43,938	219,990,032	28,599	4,400	693	10,246	10,939
	$228,260,521	$689,889	$232,565	$922,454	3,484,741,517	453,017	69,695	236,872	162,870	399,742

1/ Combined tax rate of 0.53 percent for the period October 2010-September 2011 and 0.32 percent for the period October 2011-September 2012.
2/ Twelve months ended sales each September 2011, 2012, 2013 and quarterly sales effective December 2013.
3/ Reflects PSC tax of $0.00013 and MCC tax of $0.00002 per Kwh embedded in firm rates resulting from Docket Nos. D2009.9.123 amd D2009.9.124.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN - INTERIM
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$55,080,400	**$10,975,511**	$66,055,911
Sales for Resale	41,795		41,795
Other	2,221,707		2,221,707
Total Revenues	57,343,902	10,975,511	68,319,413
Operating Expenses			
Operation and Maintenance			
Cost of Fuel and Purchased Power	19,981,388		19,981,388
Other O&M	19,649,388		19,649,388
Total O&M	39,630,776		39,630,776
Depreciation	11,041,019		11,041,019
Taxes Other Than Income	4,594,660	32,927 2/	4,627,587
Current Income Taxes	(17,085,156)	4,310,010 2/	(12,775,146)
Deferred Income Taxes	12,904,701		12,904,701
Total Expenses	51,086,000	4,342,937	55,428,937
Operating Income	$6,257,902	$6,632,574	$12,890,476
Rate Base	$169,879,751		$169,879,751
Rate of Return	**3.684%**		**7.588%**

1/ See Rule 38.5.175, page 1.
2/ Reflects taxes at 39.3875% after deducting Consumer Counsel tax of 0.1% and PSC tax of 0.2%.

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

Before the Public Service Commission of Montana

Docket No. D2015.6.____

Direct Testimony
of
Sara J. Cardwell

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

A. Yes. My name is Sara J. Cardwell, 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 Manager, Regulatory Affairs–Pricing & Tariffs for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your responsibilities as Manager, Regulatory Affairs-Pricing & Tariffs?

A. My responsibilities include the preparation of marginal class cost of service studies, embedded class cost of service studies, rate designs and miscellaneous tariff revision filings. I also administer utility tariffs and rules and regulations for each of the jurisdictions in which Montana-Dakota provides utility service.

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

A. I graduated from the University of Wisconsin-Stout with a Bachelor of Science degree in Business Administration and received my Masters in Business Administration from the University of Portland. I have worked for PacifiCorp, Portland General Electric Company, Xcel Energy and the

1 North Dakota Public Service Commission. I started working in my current
2 position at Montana-Dakota in 2014.
3 **Q. Have you testified in other proceedings before regulatory bodies?**
4 A. Yes. I have previously presented testimony before the Public
5 Service Commissions of North Dakota and Montana as well as the
6 California and Idaho Public Utilities Commissions, the Oregon Public
7 Utility Commission and the Washington Utilities and Transportation
8 Commission.
9 **Q. What is the purpose of your testimony in this proceeding?**
10 A. The purpose of my testimony is to present the results of the
11 Company's embedded class cost of service study and its marginal class
12 cost of service study.
13 **Q. What statements and exhibits are you sponsoring in this**
14 **proceeding?**
15 A. I am sponsoring Statement L, Part B of Statement O and Exhibit
16 No. ___ (SJC-1) through Exhibit No. ___ (SJC-11).
17 **Embedded Class Cost of Service Study**
18 **Q. Would you please explain the embedded class cost of service study**
19 **contained in Statement L?**
20 A. Yes. Statement L, pages 1 through 11 provides a report entitled
21 "Cost of Service by Component." This report shows the total dollars and
22 unit cost required under each rate if the Pro Forma rate of return of 7.588
23 percent were to be earned for the demand, energy and customer cost
24 components of each rate schedule.
25 A summary of the results by the major rate classifications,
26 Residential, Small General Service, Large General Service, Municipal

Pumping and Lighting is provided on page 1 of Statement L, Schedule L-1. Statement L, Schedule L-2, pages 1 through 121 is a report of the rate base, income statement and Pro Forma adjustments as allocated to each rate schedule. The allocation factor applied to the total Montana electric amount is shown on each line item and allocation factors used to allocate the total Montana electric amount to each class and cost component as referenced are provided in Statement L, Schedule L-3.

The embedded class cost of service study is based on the results for Montana electric operations for the 12 months ended December 31, 2014 as adjusted to reflect the Pro Forma adjustments as sponsored by Mr. Jacobson.

Q. What were the results of the embedded class cost of service study?

A. The overall Montana electric rate of return based on the actual results for the 12 months ending December 31, 2014 adjusted for known and measurable changes is 3.528 percent. The returns by customer class are as shown below:

Residential Service	2.201%
Small General Service	4.257%
Irrigation Service	-4.221%
Large General Service - Primary	1.755%
Large General Service - Secondary	5.858%
Large General Service Time of Day	5.417%
Contract Service	3.544%
Municipal Pumping	-0.024%
Outdoor Lighting	1.435%
Municipal Lighting	5.906%
General Electric Space Heating	2.175%

Q How did you determine what costs should be assigned to each customer class?

1 A. The starting point was classifying the functionalized costs by FERC
2 account for all rate base and income statement items as demand, energy
3 or customer related based on the component of service being provided.
4 Demand-related costs are costs that vary with the Kw demand imposed by
5 the customer, energy-related costs are costs that vary with the energy or
6 Kwh the customer uses and customer-related costs are fixed costs driven
7 by the number of customers served.
8 Next the plant, expense and revenue items that were identified as
9 directly related to a specific class of customers were directly assigned to
10 the appropriate class. Finally, the remaining costs were allocated using
11 the various allocation factors shown in Statement L, Schedule L-3, on the
12 basis of cost responsibility.
13 **Q. Would you please provide an overview of the allocation process**
14 **including the rationale underlying the choice of allocation factors?**
15 A. Yes. I will start with the plant in service items on the rate base
16 schedule starting on Schedule L-2, Page 1. The plant allocation serves as
17 the basis for allocating many of the other rate base items. The investment
18 in production related plant items was allocated on an average and excess
19 demand (AED) allocator to account for the contribution of each class
20 based on a combination of the class' average demand and non-coincident
21 peak demand. The AED factor is comprised of the sum of the average
22 demand of each class and the difference between the total system peak
23 demand and the average demand as allocated to each class based on the

1 non-coincident demand in excess of the average demand. The production
2 investment related to the Company's wind facilities was allocated on a
3 factor based 80 percent on the energy allocation factor (Factor No.1) and
4 20 percent on the AED allocator to reflect the fact the wind facilities are
5 primarily an energy resource. The investment in transmission plant
6 related items was also allocated on the AED factor. Production and
7 transmission plant investments were allocated in this manner in the class
8 studies filed in each of the Company's last three electric cases filed in
9 Montana.
10 Turning now to the distribution plant investment; each distribution
11 plant account is analyzed and allocated based on the cause for the
12 investment. Station equipment and the associated land and land rights
13 are allocated on the non-coincident peak demand of each class,
14 representing the maximum demand on the system. The next set of plant
15 items - Poles, Towers & Fixtures; Overhead Conductors & Devices;
16 Underground Conduit & Devices were classified as customer and demand
17 related based on an analysis of the minimum and normal system design
18 for a typical distribution system, with the minimum system representing the
19 percentage of the plant accounts assigned to the customer component,
20 and the remainder classified as demand related. Based on this analysis,
21 the minimum investment necessary to connect a customer was
22 determined to be 84 percent of Account 364 (Poles, Towers & Fixtures);
23 Account 365 (Overhead Conductors) and Accounts 366 and 367

(Underground Conduit and Underground Conductors and Devices). The amounts classified as customer related were then allocated to each rate class based on the number of customers served in each rate class (excluding Contract Service Rate 35), or Factor No. 8.1. Contract Service Rate 35 is excluded from this allocator as service to customers under this schedule is provided at the substation level. The amount classified as demand related was allocated to each rate class based on the maximum demand of each rate class (Non-coincident peak Factor No. 4.1). The investment in Line Transformers was also classified as customer and demand related. The percentage assigned to the customer component was determined based on the minimum intercept method which seeks to identify the portion of the transformer investment associated with a hypothetical no-load condition. Based on an analysis of the type and size of transformers, representing the minimum equipment necessary to provide service to secondary system customers, the zero intercept was determined to be $1,655. Applying this amount to the number of transformers resulted in a customer component of 79 percent with the remaining 21 percent classified as demand related. The classified costs were allocated on weighted customer transformers and the non-coincident secondary demand factor accordingly.

The four remaining distribution accounts; Services, Meters, Installation on Customer Premises and Street Light & Signal System are all related solely to a customer connection and were classified as

customer related. Services were allocated to the rate classes based on Factor 10 representing services weighted by customer class derived by comparing the installed cost per service for each rate class to the cost necessary to serve Residential Rate 10 customers. The weights were then applied to the number of customers in each rate class. The same process was used to fashion an allocation based on weighted meter costs (Factor No. 6) for allocating the embedded investment in meters. The investment in Installation on Customer Premises was directly assigned to Outdoor Lighting and the investment in Street Light & Signal Systems was directly assigned to Municipal Lighting. The allocation of the remainder of the rate base items is self explanatory with the allocation factor noted for each line item.

Q. Would you please continue your discussion of the embedded class cost of service study with an explanation of the income statement items in the study?

A. Yes. The allocation of the income statement items starts on Schedule L-2, Page 3 with the allocation of revenues. As shown, revenues are primarily directly assigned based on the revenues produced by each rate class. The other revenues are allocated based on the source of the revenue item. Each item is shown along with the allocation factor applied. Operation and maintenance expenses consisting of the cost of fuel, purchased power costs, transmission, distribution and administrative and general expenses are shown starting at Schedule L-2, page 4. The

1 production expenses are classified as demand and energy related with the
2 fuel, purchased power and variable production expenses classified as
3 energy and allocated based on the energy requirements of each class.
4 The other production expenses and purchased capacity costs are
5 classified as demand costs and allocated on the same demand allocator
6 used to allocate production plant costs. Transmission operation and
7 maintenance costs are also classified as demand related and allocated on
8 the average and excess demand allocator (Factor No. 2). The remaining
9 operation and maintenance expenses are allocated based on cost
10 causation and typically follow the plant investment previously described in
11 the rate base section. The remainder of the income statement reflects the
12 allocation of depreciation expense, taxes other than income and income
13 taxes as denoted by each line item. Finally, the pro forma adjustments as
14 discussed by Mr. Jacobson, are allocated beginning at Schedule L-2,
15 Page 7. Again the allocation primarily follows the corresponding plant or
16 expense item previously allocated. The allocation of costs to each rate
17 schedule is presented in the same format as described above.
18 **Q. For what purpose has the embedded class cost of service study**
19 **been used in this case?**
20 A. The study results have been used for the purpose of analyzing the
21 various components comprising the total rate applicable to each customer
22 class. The embedded cost study was also utilized in the development of
23 certain items in the marginal cost study.

Q. Has the Company also prepared a marginal class cost of service study?

A. Yes, the Company has prepared a marginal class cost of service study and discusses it below.

Marginal Class Cost of Service Study

Q. Please explain the elements of a marginal cost study.

A. The marginal cost study looks at the same costs that are included in the embedded study but rather than using the actual costs that make up the revenue requirement, the marginal cost study looks to what the costs would be if the system would be recast to serve the next increments of load. The marginal costs include generation, transmission lines and substations, distribution substations, lines, and transformers, service lines, metering, meter reading and billing and reactive power correction costs.

Q. Please provide a summary of the Exhibits that you are sponsoring.

A. I will be sponsoring the following list of exhibits.

– Exhibit No. ___(SJC-1)	Summary Of Total and Unit Marginal Costs By Function, Cost Classification, Customer Class, Season, And Time Of Day
– Exhibit No. ___(SJC-2)	Summary Of Energy Related Marginal Cost
– Exhibit No. ___(SJC-3)	Summary Of Capacity Related Marginal Cost
– Exhibit No. ___(SJC-4)	Summary Of Customer Related Marginal Cost
– Exhibit No. ___(SJC-5)	Summary Of Reactive Power Correction Related Marginal Cost
– Exhibit No. ___(SJC-6)	Generation Cost Derivation
– Exhibit No. ___(SJC-7)	Transmission Plant Related Capacity Cost

– Exhibit No. ___(SJC-8)	Transmission and Distribution Substation Direct Plant Cost Derivation
– Exhibit No. ___(SJC-9)	Distribution Lines and Transformers Direct Plant Cost Derivation – Capacity Related
– Exhibit No. ___(SJC-10)	Customer Related Distribution (Lines and Transformers), Service Lines, and Metering Cost Derivation
– Exhibit No. ___(SJC-11)	Meter Reading and Customer Service Cost Derivation

Q. Does the current study use the same methodology that the Company used in its last case?

A. Yes. The methodology is basically the same. There are a few changes due to software changes and the greater availability of data in some areas.

Q. What year does the marginal cost study reflect?

A. The study reflects an estimate of marginal costs for 2017. The study year is based upon the ARM 38.5.176 requirement that the study reflect costs two years beyond January 1 of the year in which the study is filed (2015).

Q. What is the time horizon for estimating the marginal costs?

A. The time horizon used in this study is dependent on the function (generation, transmission, and distribution), the quality and availability of data related to cost projections. The objective is to reflect long-run marginal costs where long-run is a five to ten year horizon. For example, the Company performs generation cost studies so the marginal generation

costs reflect estimated costs for the time horizon of those studies; an eight year period 2017 – 2024.

On the other hand, less information is available on long-term projections of marginal transmission and distribution costs. As a result, these marginal costs were developed based on a combination of historical costs and current actual or estimated construction costs. When costs from different years are incorporated into the marginal cost study I adjusted the costs for 2017 dollars based upon an assumed inflation factor or the Handy Whitman index.

Q. Please provide an overview of the calculation of marginal generation costs.

A. The starting assumption is that marginal production costs (energy and capacity) should reflect the fact that the Montana load is served as part of Montana-Dakota's integrated generation system. Therefore, marginal load and resources were analyzed at the system level versus only considering the load served within the state of Montana. Marginal energy costs were calculated based upon analyzing the marginal cost of energy over the eight year horizon 2017 – 2024 under the expected load forecast. Long-run marginal capacity costs are based upon the levelized cost of an 88 MW simple cycle combustion turbine. The marginal energy costs include adders for marginal general and administration ("G&A"), and operating and maintenance ("O&M") expenses.

1 The PLEXOS model was used to prepare the forecast of levelized
2 marginal energy costs over the period of 2017 through 2024. The model
3 provides a forecast of the least cost use of the mix of resources available
4 to meet the Company's load based upon a set of assumptions including
5 unit availability, heat rates, fuel costs, and ramp rates. The model includes
6 key assumptions about the future including Montana-Dakota's retail load,
7 estimates of future fuel prices, and characteristics of existing generation
8 units and power contracts.

9 The generation energy costs from the model are adjusted for
10 generation revenue taxes and working capital. The unit marginal energy
11 costs are costs at the busbar. Reports showing total class and system
12 marginal energy costs incorporate energy losses based on the Company's
13 energy loss calculation. The marginal energy costs for each year were
14 levelized based upon the Company's weighted average cost of capital.

15 **Q. Are the seasonal on and off-peak marginal energy costs the same for**
16 **all rate classes?**

17 A. The unit costs displayed on page 3 of Exhibit No. ___(SJC-1) are
18 the same since the numbers do not reflect differences in delivery losses.
19 However, the total marginal energy costs by season shown on page 2 of
20 Exhibit No. ___(SJC-1) reflect each class's annual energy adjusted for
21 losses and multiplied by the estimated consumption in each of the periods.

1 **Q. How were class energy use profiles for each time period estimated in**
2 **order to develop seasonal energy marginal costs at the class level?**

3 A. Load research samples for the residential, small general service
4 secondary voltage, large general service primary and secondary voltage
5 and municipal pumping classes were summarized to determine the
6 percentage of annual consumption by time period. For Rate 31, Optional
7 Time-of-Day customers, these same on-off peak periods are used for the
8 pricing of the service under this rate so on-off peak consumption was
9 available in the billing system for this schedule.

10 As load research data were not available for the remaining classes,
11 it was necessary to make assumptions about the time-of-use distribution.
12 For example, for the lighting classes, because the summer daylight period
13 extends beyond the on-peak period, it was assumed that there was no
14 consumption for these classes during the on-peak period.

15 **Q. Are any adjustments applied to the marginal capacity cost of the**
16 **combustion turbine?**

17 A. Because the Company's resource adequacy requirements in MISO
18 are less than the total capacity available, the marginal capacity costs
19 were adjusted downward to reflect the fact that the Company only needs
20 to have 87.6 percent of the generation needed to serve loads. The
21 capacity costs were also adjusted for property taxes, G&A and revenue
22 taxes.

1 **Q. Have you prepared a summary of the marginal generation costs?**

2 A. Yes, the summary is provided in Exhibit No. ___(SJC-6). Exhibit
3 No. __(SJC-3), shows the Capacity Related Marginal Costs for the
4 generation, transmission and distribution functions.

5 **Q. Did you prepare an estimate of the marginal cost associated with**
6 **reactive power?**

7 A. Yes, the marginal cost for reactive power is based upon the costs
8 for five recently installed capacitor bank projects. The costs of the five
9 projects were unitized by adding up the project costs and dividing by the
10 total capacities of the units. Adders are applied for O&M and G&A
11 expense. The reactive power marginal cost expressed in $/KVAR year is
12 assigned to rate classes that have KVAR penalty charges for customers
13 with power factors outside of the tariff range. No marginal reactive power
14 costs are assigned to the residential customer class.

15 **Q. Have you prepared a summary of the marginal reactive power cost**
16 **analysis?**

17 A. Yes, the summary is provided in Exhibit No. ___(SJC-5). This
18 exhibit presents the derivation of the costs associated with reactive power
19 correction.

20 **Q. How are marginal transmission line costs calculated?**

1 A. The calculation of marginal transmission costs is based upon
2 historical costs over the past nine years. Nine years of costs are used to
3 get a sizeable list of projects and to try to achieve a relatively stable and
4 reasonable average cost given the variation in the project sizes and
5 investment per project. Project costs across years are compared in
6 constant dollars by applying the Handy Whitman transmission cost
7 inflators for projects prior to 2014. The projects and the associated costs
8 are based upon new transmission line investment reported in the annual
9 FERC Form 1. The total cost, expressed in 2017 dollars, is divided by the
10 peak load growth to yield a cost per kW. The calculation of transmission
11 marginal capital costs yields a cost of $442.84 / kW. The analysis is
12 summarized in Exhibit No. ___(SJC-7).

13 **Q. Are other costs added to the capital costs to derive total**
14 **transmission line marginal costs?**

15 A. Yes, the capital costs are adjusted to include O&M, G&A, property
16 tax, and other tax adders.

17 **Q. How are marginal O&M transmission costs calculated?**

18 A. Marginal O&M costs are calculated using a two-step process. The
19 first step is to determine which accounts would have a marginal cost
20 component. The second step is to calculate the total historical
21 transmission O&M costs on a dollar per kW basis.

1 **Q. Which transmission expense accounts were excluded from the**
2 **marginal cost analysis?**

3 A. Three accounts were excluded from the analysis: load dispatch,
4 transmission by others, and rents. Load dispatch was excluded since
5 small increases and decreases in load are not anticipated to result in
6 changes in operations. Transmission by others was excluded since the
7 marginal cost of new transmission lines is included in the marginal cost
8 calculation. Rents were excluded for the same reason.

9 **Q. How are marginal transmission costs classified and allocated to the**
10 **customer classes?**

11 A. The costs are classified as demand related and allocated to the
12 customer classes based upon the class's average and excess demand
13 allocator adjusted for losses based upon the customer rate class.

14 **Q. Have you prepared a summary of the marginal transmission costs?**

15 A. Yes, the summary is provided in Exhibit No. ___(SJC –3), column
16 d. Exhibit No. ___(SJC-7) presents the derivation of the marginal
17 transmission costs.

18 **Q. How are marginal transmission substation costs calculated?**

19 A. Marginal substation costs are based upon the costs of four
20 transmission substations that have been recently built. The cost of each
21 substation is divided by the capacity of the substation. Transmission

1 substation costs are classified as 100 percent capacity related. Costs are
2 considered demand related since the service territory is geographically
3 static and new substation capacity is driven by increased demand or
4 reliability, where reliability is often driven by increased demand and the
5 inability to switch circuits without additional capacity. The costs are
6 allocated to the classes according to the average and excess demand
7 allocator.

8 **Q. Were any adjustments made to the capital costs of new substations**
9 **to derive total substation marginal costs?**

10 A. Yes, the costs were adjusted to reflect incremental costs for
11 property taxes, O&M, G&A, and other taxes.

12 **Q. Have you prepared a summary of the marginal transmission**
13 **substation costs?**

14 A. Yes, the summary of the marginal transmission substation costs is
15 provided in Exhibit No. ___(SJC-3) page 2, column e. Exhibit No.
16 ___(SJC-8), rows 3-7, present the derivation of the marginal transmission
17 substation costs.

18 **Q. Would you please describe how distribution substation marginal**
19 **costs are calculated?**

20 A. The approach is the same as used for calculating transmission
21 substation marginal costs. The Company has also recently completed
22 construction of four distribution substations.

1 **Q. How was the distribution substation capital cost converted to an**
2 **annual marginal cost estimate and allocated to the rate classes?**

3 A. The capital costs are levelized using a fixed charge rate and adders
4 are applied to reflect the associated marginal O&M, G&A, property tax,
5 and other tax costs. The costs were allocated to each class based upon
6 the non-coincident peaks of the Montana customer classes.

7 **Q. Have you prepared a summary of the marginal distribution**
8 **substation costs?**

9 A. Yes, the summary of the marginal distribution substation costs is
10 provided in Exhibit No. ___(SJC-3) page 2, column f. Exhibit No.
11 ___(SJC-8) rows 10-14 present the derivation of the marginal distribution
12 substation costs.

13 **Q. Please summarize what comprises the remaining distribution**
14 **marginal costs.**

15 A. The remaining distribution marginal costs include the costs for
16 distribution lines (booked in FERC accounts 363-367), distribution
17 transformers (as booked in FERC account 368), service lines (as booked
18 in FERC account 369) and metering (as booked in FERC account 370).

19 **Q. How are the marginal cost of distribution lines calculated?**

20 A. Marginal distribution line costs are based upon an engineering
21 estimate of the cost to reconstruct the existing distribution circuits in

1 Montana based on engineering estimates of those costs. The approach
2 is to estimate cost, on a per mile basis, and then convert the estimate to a
3 cost per customer based upon data on the number of circuits, circuit miles,
4 and customers on the Montana system. The total costs are classified as
5 either demand, or customer related based upon the minimum system
6 study used for the embedded cost study. Customer and demand marginal
7 costs at the system level were allocated to the classes using the same
8 allocation factors used in the embedded cost study.

9 **Q. How are marginal distribution expenses determined?**

10 A. The process is similar to the approach used for transmission
11 expenses. The different expense accounts were grouped according to
12 functions and then reviewed to determine which costs should be
13 designated as marginal. Distribution costs are also segregated into
14 different functions: substation expense (which is used as an adder to
15 distribution substations), meter related (which is associated with billing
16 and metering), line transformers, and distribution line related. Distribution
17 expenses related to miscellaneous and rents are not incorporated into the
18 marginal cost of adding distribution lines or the marginal cost of serving an
19 additional distribution customer.

20 **Q. How are distribution line costs classified?**

21 A. Distribution line costs are classified as demand and customer
22 related based upon the minimum system approach also used for the

1 embedded cost study. This resulted in 82 percent of the distribution costs
2 classified as customer related.

3 **Q. How is the marginal cost of a line transformer calculated?**

4 A. The marginal cost of line transformers is based on the cost of new
5 line transformers. The cost is customer class specific and is based upon a
6 weighting of the size of transformers used by each customer class. Line
7 transformers are classified as demand and customer related. The
8 customer proportion is based upon a linear regression of line transformer
9 size as a function of cost where the intercept of the regression line is the
10 customer proportion. The customer portion for each class is calculated
11 based upon the average number of customers on a line transformer.

12 **Q. How is the marginal cost of service lines calculated?**

13 A. The costs for typical service lines were based on the estimates
14 used to derive the service weighting factors used in the Embedded Class
15 Cost of Service Study.

16 **Q. Have you prepared a summary of the marginal distribution plant**
17 **direct costs?**

18 A. Yes, the summary of marginal capacity related distribution line
19 costs is provided in Exhibit No. ___(SJC-3) page 2, column g. The
20 summary of marginal capacity related distribution transformer costs is
21 provided in Exhibit No. ___(SJC-3) page 2, column h. The summary of
22 marginal customer related distribution transformer costs are provided in

1 Exhibit No. ___(SJC-10), column b. The summary of marginal customer
2 related distribution line costs are provided in Exhibit No. ___(SJC-10),
3 column c. The summary of capacity related marginal distribution line
4 direct plant costs are provided in Exhibit No. ___(SJC-9), rows 1-7. The
5 summary of capacity related marginal distribution transformer direct plant
6 costs are provided in Exhibit No. ___(SJC-9), rows 12-16. The summary
7 of marginal service line costs are provided in Exhibit No. ___(SJC- 10),
8 column d.

9 **Q. How are the marginal meter costs calculated?**

10 A. The marginal cost of metering is class specific based upon the
11 typical meter used by the customer class. Meter maintenance expense is
12 based upon historical average annual maintenance cost per meter. The
13 meter reading costs are based upon historical average costs associated
14 with meter reading, billing, and sales expense. The five-year averages
15 are based upon examining all the costs on a constant dollar basis.

16 **Q. Have you prepared a summary of marginal metering reading and**
17 **other customer service costs?**

18 A. Yes, please see Exhibit No. ___(SJC-11).

19 **Q. How are carrying charges for new capital investments calculated?**

20 A. Levelized fixed charge rates are based upon the capital structure
21 and cost of capital used in the embedded cost study, as well as applicable
22 book life assumptions for the capital investment associated with a given

1 function. The capital structure and cost of capital represent the
2 Company's current assumptions for 2015 as contained in Statement F. I
3 have not developed a separate cost of capital or capital structure forecast
4 for 2017, the study year's marginal cost.

5 **Q. How is the levelized fixed charge rate calculated?**

6 A. The nominal levelized fixed charge rates for generation,
7 transmission, and distribution are based upon dividing the annual
8 equivalent cost of an associated capital cost by the initial cost. The fixed
9 charge rate incorporates the annual debt and return on equity of an
10 investment assuming the annual book depreciation for each type of
11 investment, tax depreciation, normalization of taxes, and income taxes.

12 **Q. Do the marginal cost estimates include capacity and energy losses?**

13 A. The marginal unit costs, shown in Exhibit No. ___(SJC-1), page 3
14 have not been adjusted for capacity and energy losses; rather, the
15 marginal unit cost estimates were adjusted by energy and demand
16 allocation factors at the customer class level to determine total marginal
17 costs at the class level, inclusive of losses. (See Exhibit No. ___(SJC-1),
18 pages 1-2). The same loss factors are used in the embedded cost study.

19 **Q. Are marginal costs identified in more detail than the annual level?**

20 A. All marginal costs other than energy costs are initially calculated at
21 the annual level. The marginal energy generation costs for the summer
22 and winter on and off peak periods were based on output from the

1 PLEXOS model. The generation capacity, transmission line and
2 transmission substation costs are allocated only to the summer and winter
3 on-peak periods. The remaining marginal costs are allocated to each
4 season and on and off-peak periods based upon the hours in each period.

5 **Q. What are the definitions of the seasons and on and off-peak periods**
6 **used in your study?**

7 A. Winter is defined as October – May and summer is June –
8 September. Peak hours are noon to 8:00 pm. on weekdays.

9 **Q. How are the marginal costs allocated to the different customer rate**
10 **classes?**

11 A. The marginal cost study assigns the marginal costs to the different
12 customer rate classes similar to the way these costs are allocated in the
13 embedded cost study.

14 Generation marginal energy costs are allocated to the customer
15 classes based upon loss adjusted sales. Generation capacity costs along
16 with transmission related costs and transmission substation related costs
17 are allocated to the customer classes according to an average and excess
18 demand allocator. Distribution capacity related costs and distribution
19 substation costs are allocated according to the class non-coincident
20 peaks.

21 **Q. Have you prepared a summary of total customer related marginal**
22 **costs by customer class?**

1 A. Yes, please see Exhibit No. ___(SJC-4). This exhibit is based
2 upon the sum of the various customer related components of distribution
3 plant direct costs, along with the marginal costs of Meter Reading, Billing,
4 and Customer Service. As shown on the exhibit, the direct costs are
5 adjusted for O&M, G&A, working capital and taxes.

6 **Q. What are the key differences between the marginal cost study and**
7 **the embedded cost study?**

8 A. The marginal cost study does not directly translate into a revenue
9 requirement. Unlike an embedded cost study, it is not necessary to
10 allocate all costs, rather the marginal cost study only addresses
11 incremental costs. Also, unlike an embedded cost study, the marginal
12 cost study can result in the allocation of total costs that are in excess of
13 the utility's revenue requirement. In fact, the marginal cost study in this
14 filing results in higher costs than in the embedded study.
15 Individual components of the marginal cost study can be greater or
16 less than their comparable component in the embedded cost study. For
17 example, the marginal cost of billing a few more customers is likely to be
18 significantly less than the average costs spread over all customers. In
19 contrast to billing, the marginal cost of building new generation capacity is
20 typically greater than the average cost of generation in rate base. Thus,
21 the incremental costs associated with each aspect of providing electric
22 service can be either greater, or less than the embedded costs.

23 **Q. How is the marginal cost study used in Montana-Dakota's filing?**

24 The marginal cost study is provided in compliance with the ARM
25 38.5.176. The study is not used to identify the revenue requirement but

has informational value related to developing rate design. Marginal costs can provide a cost signal that guides the efficient consumption of resources. As such, the marginal cost analysis is one consideration in the decision on how to allocate costs to the different customer classes and to recover those costs through rate design.

Q. Have you prepared a reconciliation of the embedded revenue requirement to the marginal cost study?

A. Yes, as shown in the table below, the system level marginal costs are approximately 31 percent higher than the embedded cost revenue requirement.

Rate Class	Embedded Total (2015)	Marginal Total (2017)	Marginal / Embedded
Residential Rate 10	22,295,532	39,973,327	44%
Small General Rate 20	12,314,875	18,623,885	34%
Irrigation Power Rate 25	419,053	582,111	28%
Large General Primary Rate 30	3,948,571	4,817,695	18%
Large General Secondary Rate 30	12,327,440	15,276,122	19%
Large General Service TOD Rate 31	1,278,631	1,533,573	17%
Contract Services Rate 35	14,524,394	17,980,141	19%
Municipal Pumping Rate 48	721,272	943,465	24%
Outdoor Lighting Rate 52	736,025	792,183	7%
Street Lighting Rate 41	932,356	737,930	-26%
General Space Heat Rate 32	84,494	99,458	15%
Total	69,582,643	101,359,890	31%

Therefore, reconciliation between the marginal costs and embedded costs is necessary in order to utilize the marginal cost study. The reconciliation is shown on Statement M, Page 4. The results are also graphically presented in Statement O, Part B, pages 1 through 5.

Q. How do total marginal costs compare to total embedded costs?

A. The results of the study show that the system level marginal costs are approximately 31 percent higher than the embedded cost revenue

1 requirement. At the customer rate class level, the differences range from
2 being 79 percent greater than embedded costs to 21 percent lower than
3 embedded costs.

4 **Q. Does this conclude your direct testimony?**

5 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Summary Of Marginal Costs

Summary Of Marginal Costs By Customer Class and Cost Classification

Line	Description	Total Energy	Total Demand	Customer	KVAR	Total	Total without KVAR Costs
	(a)	(b)	(c)	(d)	(e)	(f) = b+c+d+e	(g) = b+c+d
1	**Rate / Summary Customer Class**						
2	Residential Rate 10	$ 10,055,878	$ 9,166,658	$ 20,750,791	$ -	$ 39,973,327	$ 39,973,327
3	Small General Primary Rate 20	$ 4,808	$ 3,537	$ 7,119	$ 11	$ 15,475	$ 15,464
4	Small General Secondary Rate 20	$ 6,620,471	$ 5,257,991	$ 6,727,819	$ 2,129	$ 18,608,410	$ 18,606,281
6	General Space Heat Rate 32	$ 54,086	$ 42,984	$ 2,388	$ -	$ 99,458	$ 99,458
5	Irrigation Power Rate 25	$ 137,201	$ 269,329	$ 175,251	$ 330	$ 582,111	$ 581,781
6	Large General Primary Rate 30	$ 2,427,650	$ 2,360,307	$ 25,416	$ 4,322	$ 4,817,695	$ 4,813,373
7	Large General Secondary Rate 30	$ 8,771,698	$ 5,987,215	$ 509,276	$ 7,933	$ 15,276,122	$ 15,268,189
8	Large General Service TOD Rate 31- Secondary	$ 32,130	$ 70,338	$ 11,910	$ 712	$ 115,090	$ 114,378
9	Large General Service TOD Rate 31- Primary	$ 773,164	$ 641,414	$ 3,833	$ 72	$ 1,418,483	$ 1,418,411
10	Contract Services Rate 35	$ 11,573,487	$ 6,379,629	$ 23,449	$ 3,576	$ 17,980,141	$ 17,976,565
11	Municipal Pumping Rate 48	$ 376,527	$ 401,538	$ 164,678	$ 722	$ 943,465	$ 942,743
12	Outdoor Lighting Rate 52	$ 166,828	$ 129,865	$ 495,490	$ -	$ 792,183	$ 792,183
13	Street Lighting Company Owned Rate 41	$ 313,425	$ 243,483	$ 53,633	$ -	$ 610,541	$ 610,541
14	Street Lighting Municipal Owned Rate 41	$ 42,167	$ 32,683	$ 52,539	$ -	$ 127,389	$ 127,389
15	Total	$ 41,349,520	$ 30,986,971	$ 29,003,592	$ 19,807	$ 101,359,890	$ 101,340,083
16							
17							

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Summary Of Marginal Costs

Summary Of Marginal Costs By Customer Class, Season, And Time Of Day

Line	Description	Summer On Peak	Summer Off Peak	Winter On Peak	Winter Off Peak	Total
	(a)	(b)	(c)	(d)	(e)	(f) = b+c+d+e
1	**Rate / Summary Customer Class**					
2	Residential Rate 10	$ 6,243,076	$ 6,966,129	$ 11,987,288	$ 14,776,823	$ 39,973,316
3	Small General Primary Rate 20	$ 2,491	$ 2,590	$ 4,892	$ 5,500	$ 15,473
4	Small General Secondary Rate 20	$ 3,168,334	$ 2,925,674	$ 6,215,860	$ 6,298,551	$ 18,608,419
6	General Space Heat Rate 32	$ 20,032	$ 12,184	$ 39,125	$ 28,117	$ 99,458
5	Irrigation Power Rate 25	$ 129,915	$ 139,791	$ 179,802	$ 132,603	$ 582,111
6	Large General Primary Rate 30	$ 764,885	$ 366,525	$ 1,969,008	$ 1,717,278	$ 4,817,696
7	Large General Secondary Rate 30	$ 2,692,523	$ 1,826,463	$ 5,619,647	$ 5,137,491	$ 15,276,124
8	Large General Service TOD Rate 31- Secondary	$ 20,082	$ 12,241	$ 47,797	$ 34,970	$ 115,090
9	Large General Service TOD Rate 31- Primary	$ 237,068	$ 218,767	$ 480,450	$ 482,198	$ 1,418,483
10	Contract Services Rate 35	$ 3,128,658	$ 2,558,124	$ 6,458,683	$ 5,834,677	$ 17,980,142
11	Municipal Pumping Rate 48	$ 168,888	$ 145,753	$ 348,451	$ 280,374	$ 943,466
12	Outdoor Lighting Rate 52	$ 90,995	$ 156,437	$ 191,791	$ 352,961	$ 792,184
13	Street Lighting Company Owned Rate 41	$ 73,049	$ 97,868	$ 166,695	$ 272,928	$ 610,540
14	Street Lighting Municipal Owned Rate 41	$ 14,845	$ 23,274	$ 32,420	$ 56,849	$ 127,388
15	Total	$ 16,754,841	$ 15,451,820	$ 33,741,909	$ 35,411,320	$ 101,359,890
16						
17	**Notes**					
18	(1) Generation Energy Costs spread to period based on Plexos results, Generation Demand allocated to Summer and Winter Peak					
19	(2) Non-Generation costs spread to period based on number of hours in period.					
20	(3) 2014 $					

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Summary of Marginal Unit Costs by Function, Classification, Period And Rate Class
2017$

Line	Description	$ per KWH	$ per KW per Year	$ per Customer per Year	$ per KVAR per Month
	(a)	(b)	(e)	(f)	(g)
1	**Total Energy Related Marginal Cost**				
2	Generation - Average	$ 0.0472			
3	Winter Off-Peak	$ 0.0494			
4	Winter On-Peak	$ 0.0501			
5	Summer Off-Peak	$ 0.0421			
6	Summer On-Peak	$ 0.0454			
7					
8					
9					
10					
11					
12	**Total Capacity Related Marginal Cost**				
13	Generation - Average		$ 106.20		
14	Transmission - Average		$ 56.99		
15	Substation (Transmission) - Average		$ 14.65		
16	Substation (Distribution) - Average		$ 12.51		
17	Distribution (Lines) - Average		$ 19.67		
18	Distribution (Transformers) - Average		$ 4.58		
19					
20					
21	**Reactive Power - Average**				$ 0.48
22					
23	**Total Customer Related Marginal Cost**				
24	Distribution (Lines and Transformers) And Service Lines, Metering, Meter Reading / Billing - Average				
25	Residential Rate 10			$ 1,034.23	
27	Small General Primary Rate 20			$ 1,423.77	
28	Small General Secondary Rate 20			$ 1,170.87	
29	General Space Heat Rate 32			$ 265.33	
30	Irrigation Power Rate 25			$ 1,550.89	
32	Large General Primary Rate 30			$ 1,815.44	
33	Large General Secondary Rate 30			$ 1,943.80	
34	Large General TOD Rate 31 -Secondary			$ 1,701.39	
35	Large General TOD Rate 31 -Primary			$ 1,916.27	
36	Contract Services Rate 35			$ 1,954.08	
37	Municipal Pumping Rate 48			$ 1,483.59	
38	Outdoor Lighting Rate 52			$ 280.89	
39	Street Lighting Company Owned Rate 41			$ 1,094.56	
40	Street Lighting Municipal Owned Rate 41			$ 1,094.56	
41					
42	**Notes:**				
43	Unit Costs exclude loss adjustments. These unit costs are applied to loss adjusted commodity and demand estimates in order to determine total marginal cost.				
44					
45					

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Energy Related Marginal Costs

Line	Description	Calculations	Generation Average Annual	Generation Winter Off-Peak	Generation Winter On-Peak	Generation Summer Off-Peak	Generation Summer On-Peak
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Energy Related Direct Plant - $/KWH	= 6 x 7	$ -	$ -	$ -	$ -	$ -
2	Energy Related Plant (2014 $) - $/KWH	= input	$ -	$ -	$ -	$ -	$ -
3	Adjustment for Reserve Requirements @15% (Generation Capacity Only) - $/KWH	= 2 x 1.15	$ -	$ -	$ -	$ -	$ -
4	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061	1.061	1.061	1.061
6	Energy Related Plant (2017 $) - $/KWH	= 3 x 5	$ -	$ -	$ -	$ -	$ -
7	LFCR - %	= input	10.07%	10.07%	10.07%	10.07%	10.07%
8							
9							
10							
11							
12	Energy Related O&M Expense - $/KWH	= 13 x 15	$ 0.0460	$ 0.0482	$ 0.0489	$ 0.0409	$ 0.0442
13	Energy Related O&M Expense (2017 $) - $/KWH	= Exh SJC - 6	$ 0.0460	$ 0.0482	$ 0.0489	$ 0.0409	$ 0.0442
14	Annual Inflation - %	= input	0.00%	0.00%	0.00%	0.00%	0.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.000	1.000	1.000	1.000	1.000
16							
17							
18							
19							
20	Energy Related G&A Expense - $/KWH	= 21 x 12	$ -	$ -	$ -	$ -	$ -
21	G&A Loading Factor - %	= input	0.00%	0.00%	0.00%	0.00%	0.00%
22	Energy Related Property Taxes - $/KWH	= 23 x 6	$ -	$ -	$ -	$ -	$ -
23	Effective Property Tax as % of Direct Plant - %	= input	0.3361%	0.3361%	0.3361%	0.3361%	0.3361%
24	Energy Related Generation Taxes - $/KWH	= 25	$ 0.0009	$ 0.0009	$ 0.0009	$ 0.0009	$ 0.0009
25	Generation Tax (Total Effective Rate) - $/KWH	= input	$ 0.0009	$ 0.0009	$ 0.0009	$ 0.0009	$ 0.0009
26	Energy Related Payroll Taxes - $/KWH	= 27 x (12+20)	$ -	$ -	$ -	$ -	$ -
27	Average Payroll Tax As % Of O%M - %	= input	0.00%	0.00%	0.00%	0.00%	0.00%
28	Working Capital Annual Requirement - $/KWH	= 35 x36	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002
29	Materials And Supplies - $/KWH	= 30 x (6+10)	$ -	$ -	$ -	$ -	$ -
30	Materials And Supplies Factor - %	= input	1.44%	1.44%	1.44%	1.44%	1.44%
31	Prepayments - $/KWH	= 32 x (6+10)	$ -	$ -	$ -	$ -	$ -
32	Prepayments Factor - %	= input	0.02%	0.02%	0.02%	0.02%	0.02%
33	Fuel Stocks - $/KWH	= 34	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0015
34	Fuel Stocks Adder - $/KWH	= input	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0015
35	Total Working Capital - $/KWH	= 29+31+33	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0015
36	Required Return On Working Capital - %	= input	10.84%	10.84%	10.84%	10.84%	10.84%
37	Total Revenue Related Taxes Marginal Cost - $/KWH	= (1+12+20+26+28) x 38	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%	0.30%	0.30%	0.30%
39	Total Energy Related Marginal Cost - $/KWH	= 1+12+20+24+26+28+37	$ 0.0472	$ 0.0494	$ 0.0501	$ 0.0421	$ 0.0454
40							

Notes:
(1) 2017 $

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Capacity Related Marginal Costs

Line	Description	Calculations	Generation	Transmission
	(a)	(b)	(c)	(d)
1	Capacity Related Direct Plant - $/KW - Yr	= 6 x 7	$88.21	$41.44
2	Capacity Related Plant (2017 $) - $/KW	= Exh SJC 6, 7, 8, and 9	$100.70	$442.84
3	Adjustment for MISO Resource Adequacy Requirements @ 87.6% (Generation Energy Only)		87.6%	
4	Annual Inflation - %	= input	0.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.000	1.061
6	Capacity Related Plant (2017 $) - $/KW	= 2 x 5 (1)	$88.21	$469.85
7	LFCR (2) - %	= input	100.00%	8.82%
8				
9				
10				
11				
12	Capacity Related O&M Expense - $/KW - Yr	= 13 x 15	$12.12	$9.86
13	Capacity Related O&M Expense (2017 $) - $/KW	= input	$12.12	$9.29
14	Annual Inflation - %	= input	0.00%	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.000	1.061
16				
17				
18				
19				
20	Capacity Related G&A Expense - $/KW - Yr	= 21 x 12	$4.72	$3.84
21	G&A Loading Factor - %	= input	38.97%	38.97%
22	Capacity Related Property Taxes - $/KW - Yr	= 23 x 1	0.30	0.51
23	Effective Property Tax as % of Direct Plant - %	= input	0.00	0.01
24				
25				
26	Capacity Related Payroll Taxes - $/KW - Yr	= 27 x (12+20)	0.53	0.43
27	Average Payroll Tax As % Of O%M - %	= input	3.16%	3.16%
28	Working Capital Annual Requirement - $/KW - Yr	= 35 x36	$0.00	$0.74
29	Materials And Supplies - $/KW	= 30 x 6	$0.00	$6.77
30	Materials And Supplies Factor - %	= input	0.00%	1.44%
31	Prepayments - $/KW	= 32 x 6	$0.00	$0.09
32	Prepayments Factor - %	= input	0.00%	0.02%
33				
34				
35	Total Working Capital - $/KW	= 29+31	$0.00	$6.86
36	Required Return On Working Capital - %	= input	10.843%	10.843%
37	Total Revenue Related Taxes Marginal Cost - $/KW - Yr	= (1+12+20+26+28) x 38	$0.32	$0.17
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%
39	Total Capacity Related Marginal Cost - $/KW - Yr	= 1+12+20+22+26+28 +37	$106.20	$56.99
40				
41				
42				
43	**Notes:**			
44	(1) Generation is Line 3 times Line 5. All others are Line 2 times Line 5			
45	(2) Generation costs have already been levelized so no Levelized Fixed Charge Rate applied.			
46	(3) 2017 $			

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Capacity Related Marginal Costs

Line	Description	Calculations	Substation (Transmission)	Substation (Distribution)	Distribution (Lines)	Distribution (Transformers)
	(a)	(b)	(e)	(f)	(g)	(h)
1	Capacity Related Direct Plant - $/KW - Yr	= 6 x 7	$10.93	$11.02	$15.62	$1.33
2	Capacity Related Plant (2017 $) - $/KW	= Exh SJC 6, 7, 8, and 9	$119.22	$117.72	$155.80	$13.30
3	Adjustment for Reserve Requirements @15% (Generation Energy Only)					
4	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061	1.061	1.061
6	Capacity Related Plant (2017 $) - $/KW	= 2 x 5 (1)	$126.49	$124.90	$165.30	$14.11
7	LFCR (2) - %	= input	8.64%	8.82%	9.45%	9.45%
8						
9						
10						
11						
12	Capacity Related O&M Expense - $/KW - Yr	= 13 x 15	$2.33	$0.59	$2.21	$2.21
13	Capacity Related O&M Expense (2017 $) - $/KW	= input	$2.20	$0.56	$2.08	$2.08
14	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061	1.061	1.061
16						
17						
18						
19						
20	Capacity Related G&A Expense - $/KW - Yr	= 21 x 12	$0.91	$0.23	$0.86	$0.86
21	G&A Loading Factor - %	= input	38.97%	38.97%	38.97%	38.97%
22	Capacity Related Property Taxes - $/KW - Yr	= 23 x 1	0.14	0.40	0.56	0.05
23	Effective Property Tax as % of Direct Plant - %	= input	0.01	0.04	0.04	0.04
24						
25						
26	Capacity Related Payroll Taxes - $/KW - Yr	= 27 x (12+20)	0.10	0.03	0.10	0.10
27	Average Payroll Tax As % Of O%M - %	= input	3.16%	3.16%	3.16%	3.16%
28	Working Capital Annual Requirement - $/KW - Yr	= 35 x36	$0.20	$0.20	$0.26	$0.02
29	Materials And Supplies - $/KW	= 30 x 6	$1.82	$1.80	$2.38	$0.20
30	Materials And Supplies Factor - %	= input	1.44%	1.44%	1.44%	1.44%
31	Prepayments - $/KW	= 32 x 6	$0.03	$0.02	$0.03	$0.00
32	Prepayments Factor - %	= input	0.02%	0.02%	0.02%	0.02%
33						
34						
35	Total Working Capital - $/KW	= 29+31	$1.85	$1.82	$2.41	$0.20
36	Required Return On Working Capital - %	= input	10.843%	10.843%	10.843%	10.843%
37	Total Revenue Related Taxes Marginal Cost - $/KW - Yr	= (1+12+20+26+28) x 38	$0.04	$0.04	$0.06	$0.01
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%	0.30%	0.30%
39	Total Capacity Related Marginal Cost - $/KW - Yr	= 1+12+20+22+26+28 +37	$14.65	$12.51	$19.67	$4.58
40						
41						
42						
43	Notes:					
44	(1) Generation is Line 3 times Line 5. All others are Line 2 times Line 5					
45	(2) Generation costs have already been levelized so no Levelized Fixed Charge Rate applied.					
46	(3) 2017 $					

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Customer Related Marginal Costs

Distribution (Lines and Transformers) and Service Lines, Metering, Meter Reading / Billing Functions

	Description	Calculations	Residential Rate 10	Small General Primary Rate 20
	(a)	(b)	(c)	(d)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 652.37	$ 928.76
2	Customer Related Plant (2014 $) - $/Cust	= Exh SJC 10	$ 5,672.13	$ 8,075.31
3				
4	Annual Inflation - %	= input	2.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
6	Customer Related Plant (2017 $) - $/Cust	= 3 x 5	$ 6,018.13	$ 8,567.90
7	LFCR - %	= input	10.84%	10.84%
8				
9				
10				
11				
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 84.00	$ 84.00
13	Customer Related O&M Expense (2014 $) - $/Cust	= input	$ 79.17	$ 79.17
14	Annual Inflation - %	= input	2.00%	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 31.99	$ 48.00
17	Meter Reading, Cust Acct, Svc & Sales Adders (2014 $) - $/Cust	= Exh SJC - 11	$ 30.15	$ 45.24
18	Annual Inflation - %	= input	2.00%	2.00%
19	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 32.73	$ 32.73
21	G&A Loading Factor - %	= input	38.97%	38.97%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 215.82	$ 307.25
23	Effective Property Tax as % of Direct Plant	= input	3.5861%	3.5861%
24				
25				
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 4.70	$ 5.21
27	Average Payroll Tax As % Of O%M - %	= input	3.16%	3.16%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 9.53	$ 13.56
29	Materials And Supplies - $/Cust	= 30 x 6	$ 86.66	$ 123.38
30	Materials And Supplies Factor - %	= input	1.44%	1.44%
31	Prepayments - $/Cust	= 32 x 6	$ 1.20	$ 1.71
32	Prepayments Factor - %	= input	0.02%	0.02%
33				
34				
35	Total Working Capital - $/Cust	= 29+31+33	$ 87.86	$ 125.09
36	Required Return On Working Capital - %	= input	10.84%	10.84%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 3.09	$ 4.26
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 1,034.23	$ 1,423.77
40				
41	Notes:			
42	(1) 2017 $			
43				
44				
45				

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Customer Related Marginal Costs

Distribution (Lines and Transformers) and Service Lines, Metering, Meter Reading / Billing Functions

	Description	Calculations	Small General Secondary Rate 20	Irrigation Power Rate 25
	(a)	(b)	(e)	(f)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 746.26	$ 1,007.76
2	Customer Related Plant (2014 $) - $/Cust	= Exh SJC 10	$ 6,488.49	$ 8,762.17
3				
4	Annual Inflation - %	= input	2.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
6	Customer Related Plant (2017 $) - $/Cust	= 3 x 5	$ 6,884.29	$ 9,296.66
7	LFCR - %	= input	10.84%	10.84%
8				
9				
10				
11				
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 84.00	$ 84.00
13	Customer Related O&M Expense (2014 $) - $/Cust	= input	$ 79.17	$ 79.17
14	Annual Inflation - %	= input	2.00%	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 41.60	$ 67.82
17	Meter Reading, Cust Acct, Svc & Sales Adders (2014 $) - $/Cust	= Exh SJC - 11	$ 39.21	$ 63.92
18	Annual Inflation - %	= input	2.00%	2.00%
19	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 32.73	$ 32.73
21	G&A Loading Factor - %	= input	38.97%	38.97%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 246.88	$ 333.39
23	Effective Property Tax as % of Direct Plant	= input	3.5861%	3.5861%
24				
25				
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 5.00	$ 5.83
27	Average Payroll Tax As % Of O%M - %	= input	3.16%	3.16%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 10.90	$ 14.72
29	Materials And Supplies - $/Cust	= 30 x 6	$ 99.13	$ 133.87
30	Materials And Supplies Factor - %	= input	1.44%	1.44%
31	Prepayments - $/Cust	= 32 x 6	$ 1.38	$ 1.86
32	Prepayments Factor - %	= input	0.02%	0.02%
33				
34				
35	Total Working Capital - $/Cust	= 29+31+33	$ 100.51	$ 135.73
36	Required Return On Working Capital - %	= input	10.84%	10.84%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 3.50	$ 4.64
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 1,170.87	$ 1,550.89
40				
41	**Notes:**			
42	(1) 2017 $			
43				
44				
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MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Customer Related Marginal Costs

Distribution (Lines and Transformers) and Service Lines, Metering, Meter Reading / Billing Functions

	Description	Calculations	Large General Primary Rate 30	Large General Secondary Rate 30
	(a)	(b)	(g)	(h)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 1,183.69	$ 1,281.27
2	Customer Related Plant (2014 $) - $/Cust	= Exh SJC 10	$ 10,291.82	$ 11,140.26
3				
4	Annual Inflation - %	= input	2.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
6	Customer Related Plant (2017 $) - $/Cust	= 3 x 5	$ 10,919.62	$ 11,819.82
7	LFCR - %	= input	10.84%	10.84%
8				
9				
10				
11				
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 84.00	$ 84.00
13	Customer Related O&M Expense (2014 $) - $/Cust	= input	$ 79.17	$ 79.17
14	Annual Inflation - %	= input	2.00%	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 94.05	$ 90.85
17	Meter Reading, Cust Acct, Svc & Sales Adders (2014 $) - $/Cust	= Exh SJC - 11	$ 88.64	$ 85.63
18	Annual Inflation - %	= input	2.00%	2.00%
19	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 32.73	$ 32.73
21	G&A Loading Factor - %	= input	38.97%	38.97%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 391.59	$ 423.87
23	Effective Property Tax as % of Direct Plant	= input	3.5861%	3.5861%
24				
25				
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 6.66	$ 6.56
27	Average Payroll Tax As % Of O%M - %	= input	3.16%	3.16%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 17.29	$ 18.71
29	Materials And Supplies - $/Cust	= 30 x 6	$ 157.24	$ 170.21
30	Materials And Supplies Factor - %	= input	1.44%	1.44%
31	Prepayments - $/Cust	= 32 x 6	$ 2.18	$ 2.36
32	Prepayments Factor - %	= input	0.02%	0.02%
33				
34				
35	Total Working Capital - $/Cust	= 29+31+33	$ 159.42	$ 172.57
36	Required Return On Working Capital - %	= input	10.84%	10.84%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 5.43	$ 5.81
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 1,815.44	$ 1,943.80
40				
41	Notes:			
42	(1) 2017 $			
43				
44				
45				

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Customer Related Marginal Costs

Distribution (Lines and Transformers) and Service Lines, Metering, Meter Reading / Billing Functions

	Description	Calculations	Large General Service TOD Rate 31-Secondary	Large General Service TOD Rate 31-Primary
	(a)	(b)	(i)	(j)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 1,059.18	$ 1,183.37
2	Customer Related Plant (2014 $) - $/Cust	= Exh SJC 10	$ 9,209.27	$ 10,289.05
3				
4	Annual Inflation - %	= input	2.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
6	Customer Related Plant (2017 $) - $/Cust	= 3 x 5	$ 9,771.03	$ 10,916.68
7	LFCR - %	= input	10.84%	10.84%
8				
9				
10				
11				
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 84.00	$ 84.00
13	Customer Related O&M Expense (2014 $) - $/Cust	= input	$ 79.17	$ 79.17
14	Annual Inflation - %	= input	2.00%	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 146.21	$ 191.93
17	Meter Reading, Cust Acct, Svc & Sales Adders (2014 $) - $/Cust	= Exh SJC - 11	$ 137.80	$ 180.90
18	Annual Inflation - %	= input	2.00%	2.00%
19	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 32.73	$ 32.73
21	G&A Loading Factor - %	= input	38.97%	38.97%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 350.40	$ 391.48
23	Effective Property Tax as % of Direct Plant	= input	3.5861%	3.5861%
24				
25				
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 8.31	$ 9.75
27	Average Payroll Tax As % Of O%M - %	= input	3.16%	3.16%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 15.47	$ 17.28
29	Materials And Supplies - $/Cust	= 30 x 6	$ 140.70	$ 157.20
30	Materials And Supplies Factor - %	= input	1.44%	1.44%
31	Prepayments - $/Cust	= 32 x 6	$ 1.95	$ 2.18
32	Prepayments Factor - %	= input	0.02%	0.02%
33				
34				
35	Total Working Capital - $/Cust	= 29+31+33	$ 142.65	$ 159.38
36	Required Return On Working Capital - %	= input	10.84%	10.84%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 5.09	$ 5.73
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 1,701.39	$ 1,916.27
40				
41	**Notes:**			
42	(1) 2017 $			
43				
44				
45				

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Customer Related Marginal Costs

Distribution (Lines and Transformers) and Service Lines, Metering, Meter Reading / Billing Functions

	Description	Calculations	Contract Services Rate 35	Municipal Pumping Rate 48
	(a)	(b)	(k)	(l)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 1,284.96	$ 965.50
2	Customer Related Plant (2014 $) - $/Cust	= Exh SJC 10	$ 11,172.32	$ 8,394.75
3				
4	Annual Inflation - %	= input	2.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
6	Customer Related Plant (2017 $) - $/Cust	= 3 x 5	$ 11,853.83	$ 8,906.83
7	LFCR - %	= input	10.84%	10.84%
8				
9				
10				
11				
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 84.00	$ 84.00
13	Customer Related O&M Expense (2014 $) - $/Cust	= input	$ 79.17	$ 79.17
14	Annual Inflation - %	= input	2.00%	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 95.97	$ 57.89
17	Meter Reading, Cust Acct, Svc & Sales Adders (2014 $) - $/Cust	= Exh SJC - 11	$ 90.45	$ 54.56
18	Annual Inflation - %	= input	2.00%	2.00%
19	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 32.73	$ 32.73
21	G&A Loading Factor - %	= input	38.97%	38.97%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 425.09	$ 319.41
23	Effective Property Tax as % of Direct Plant	= input	3.5861%	3.5861%
24				
25				
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 6.72	$ 5.52
27	Average Payroll Tax As % Of O%M - %	= input	3.16%	3.16%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 18.77	$ 14.10
29	Materials And Supplies - $/Cust	= 30 x 6	$ 170.70	$ 128.26
30	Materials And Supplies Factor - %	= input	1.44%	1.44%
31	Prepayments - $/Cust	= 32 x 6	$ 2.37	$ 1.78
32	Prepayments Factor - %	= input	0.02%	0.02%
33				
34				
35	Total Working Capital - $/Cust	= 29+31+33	$ 173.07	$ 130.04
36	Required Return On Working Capital - %	= input	10.84%	10.84%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 5.84	$ 4.44
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 1,954.08	$ 1,483.59
40				
41	Notes:			
42	(1) 2017 $			
43				
44				
45				

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Customer Related Marginal Costs

Distribution (Lines and Transformers) and Service Lines, Metering, Meter Reading / Billing Functions

	Description	Calculations	Outdoor Lighting Rate 52	Street Lighting Company Owned Rate 41	Street Lighting Municipal Owned Rate 41
	(a)	(b)	(m)	(n)	(o)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 94.12	$ 697.08	$ 697.08
2	Customer Related Plant (2014 $) - $/Cust	= Exh SJC 10	$ 818.36	$ 6,060.93	$ 6,060.93
3					
4	Annual Inflation - %	= input	2.00%	2.00%	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061	1.061
6	Customer Related Plant (2017 $) - $/Cust	= 3 x 5	$ 868.28	$ 6,430.65	$ 6,430.65
7	LFCR - %	= input	10.84%	10.84%	10.84%
8					
9					
10					
11					
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 84.00	$ 84.00	$ 84.00
13	Customer Related O&M Expense (2014 $) - $/Cust	= input	$ 79.17	$ 79.17	$ 79.17
14	Annual Inflation - %	= input	2.00%	2.00%	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061	1.061
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 31.99	$ 31.99	$ 31.99
17	Meter Reading, Cust Acct, Svc & Sales Adders (2014 $) - $/Cust	= Exh SJC - 11	$ 30.15	$ 30.15	$ 30.15
18	Annual Inflation - %	= input	2.00%	2.00%	2.00%
19	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061	1.061	1.061
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 32.73	$ 32.73	$ 32.73
21	G&A Loading Factor - %	= input	38.97%	38.97%	38.97%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 31.14	$ 230.61	$ 230.61
23	Effective Property Tax as % of Direct Plant	= input	3.5861%	3.5861%	3.5861%
24					
25					
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 4.70	$ 4.70	$ 4.70
27	Average Payroll Tax As % Of O%M - %	= input	3.16%	3.16%	3.16%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 1.37	$ 10.18	$ 10.18
29	Materials And Supplies - $/Cust	= 30 x 6	$ 12.50	$ 92.60	$ 92.60
30	Materials And Supplies Factor - %	= input	1.44%	1.44%	1.44%
31	Prepayments - $/Cust	= 32 x 6	$ 0.17	$ 1.29	$ 1.29
32	Prepayments Factor - %	= input	0.02%	0.02%	0.02%
33					
34					
35	Total Working Capital - $/Cust	= 29+31+33	$ 12.67	$ 93.89	$ 93.89
36	Required Return On Working Capital - %	= input	10.84%	10.84%	10.84%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 0.84	$ 3.27	$ 3.27
38	Revenue-Related Tax Rate - %	= input	0.30%	0.30%	0.30%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 280.89	$ 1,094.56	$ 1,094.56
40					
41	**Notes:**				
42	(1) 2017 $				
43					
44					
45					

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Customer Related Marginal Costs

Distribution (Lines and Transformers) and Service Lines, Metering, Meter Reading / Billing Functions

	Description	Calculations	General Space Heat Rate 32
	(a)	(b)	(p)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 82.59
2	Customer Related Plant (2014 $) - $/Cust	= Exh SJC 10	$ 718.10
3			
4	Annual Inflation - %	= input	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061
6	Customer Related Plant (2017 $) - $/Cust	= 3 x 5	$ 761.90
7	LFCR - %	= input	10.84%
8			
9			
10			
11			
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 84.00
13	Customer Related O&M Expense (2014 $) - $/Cust	= input	$ 79.17
14	Annual Inflation - %	= input	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 31.99
17	Meter Reading, Cust Acct, Svc & Sales Adders (2014 $) - $/Cust	= Exh SJC - 11	$ 30.15
18	Annual Inflation - %	= input	2.00%
19	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 32.73
21	G&A Loading Factor - %	= input	38.97%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 27.32
23	Effective Property Tax as % of Direct Plant	= input	3.5861%
24			
25			
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 4.70
27	Average Payroll Tax As % Of O%M - %	= input	3.16%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 1.21
29	Materials And Supplies - $/Cust	= 30 x 6	$ 10.97
30	Materials And Supplies Factor - %	= input	1.44%
31	Prepayments - $/Cust	= 32 x 6	$ 0.15
32	Prepayments Factor - %	= input	0.02%
33			
34			
35	Total Working Capital - $/Cust	= 29+31+33	$ 11.12
36	Required Return On Working Capital - %	= input	10.84%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 0.79
38	Revenue-Related Tax Rate - %	= input	0.30%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 265.33
40			
41	**Notes:**		
42	(1) 2017 $		
43			
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45			

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Marginal Cost to Correct Reactive Power

Line	Description	Calculations	Reactive Power
	(a)	(b)	(c)
1	Reactive Power Related Direct Plant - $/KVAR - Yr	= 6 x 7	$ 5.42
2	Reactive Power Related Plant (2014 $) - $/KVAR		$ 57.95
3			
4	Annual Inflation - %	= input	2.00%
5	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061
6	Reactive Power Related Plant (2017 $) - $/KVAR	= 3 x 5	$ 61.48
7	LFCR - %	= input	8.82%
8			
9			
10			
11			
12	Reactive Power Related O&M Expense - $/KVAR - Yr	= 13 x 15	$ -
13	Reactive Power Related O&M Expense (2014 $) - $/KVAR	= input	$ -
14	Annual Inflation - %	= input	2.00%
15	Inflation Adjustment Rate (2017 $) - Rate	= (1+0.02)^3	1.061
16			
17			
18			
19			
20	Reactive Power Related G&A Expense - $/KVAR - Yr	= 21 x 12	$ -
21	G&A Loading Factor - %	= input	38.97%
22	Reactive Power Related Property Taxes - $/KVAR - Yr	= 23 x 6	$ 0.19
23	Property Tax (Effective Rate) - $/KVAR	= input	3.5861%
24			
25			
26	Reactive Power Related Payroll Taxes - $/KVAR - Yr	= 27 x (12+20)	$ -
27	Average Payroll Tax as % of O&M - %	= input	3.16%
28	Working Capital Annual Requirement - $/KVAR - Yr	= 35 x36	$ 0.10
29	Materials and Supplies - $/KVAR	= 30 x 6	$ 0.89
30	Materials and Supplies Factor - %	= input	1.44%
31	Prepayments - $/KVAR	= 32 x 6	$ 0.01
32	Prepayments Factor - %	= input	0.02%
33			
34			
35	Total Working Capital - $/KVAR	= 29+31+33	$ 0.90
36	Required Return on Working Capital - %	= input	10.843%
37	Total Revenue Related Taxes Marginal Cost - $/KVAR - Yr	= (1+12+20+26+28) x 38	$ 0.02
38	Revenue-Related Tax Rate - %	= input	0.30%
39	Total Reactive Power Related Marginal Cost - $/KVAR - Yr	= 1+12+20+22+26+28+37	$ 5.73
40			
41			
42	**Notes:**		
43	(1) 2017 $		
44			
45			

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Generation Related Marginal Energy Costs

	Description	Average Nominal Energy ($/MWH)	Winter Off-Peak ($/MWH)	Winter On Peak ($/MWH)	Summer Off-Peak ($/MWH)	Summer On Peak ($/MWH)
	(a)	(b)	(c)	(d)	(e)	(f)
18	**Seasonalized Marginal Energy Cost**					
19	Year					
20	2017	$ 36.50	$ 38.45	$ 39.06	$ 32.49	$ 33.03
21	2018	$ 38.57	$ 40.76	$ 41.02	$ 34.07	$ 34.67
22	2019	$ 41.01	$ 43.07	$ 43.60	$ 36.19	$ 39.24
23	2020	$ 43.32	$ 45.94	$ 46.98	$ 37.76	$ 39.18
24	2021	$ 45.75	$ 48.69	$ 49.80	$ 39.85	$ 40.01
25	2022	$ 49.28	$ 51.27	$ 51.83	$ 44.81	$ 46.99
26	2023	$ 52.73	$ 54.26	$ 54.27	$ 47.47	$ 56.75
27	2024	$ 56.13	$ 57.27	$ 58.68	$ 51.11	$ 62.81
28		$ 268.59	$ 281.23	$ 285.29	$ 238.96	$ 257.76
29	Levelized Generation Energy Related Cost (Seasonal) - $/MWH	$ 46.01	$ 48.18	$ 48.87	$ 40.93	$ 44.16
30	Levelized Generation Energy Related Cost (Seasonal) - Cents/KWH	4.6010	4.8180	4.8870	4.0930	4.4160
31	Seasonal Marginal Energy Cost as % of Average Annual Marginal Cost	100.0%	104.7%	106.2%	89.0%	96.0%
32						
33						
34	**Notes:**					
35	(1) Montana Dakota PLEXOS Runs					
36	(2) Annual energy costs are nominal - levelized costs are in 2017 $					
37	(3) Discount Rate = Weighted Cost Of Capital = 7.588%					
38						
39						
40						

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Generation Related Marginal Capacity Costs

	Description	Annual Capacity Cost	Discount Factor	Present Value
	(a)	(b)	(c) = 1/(1+discount rate)^(n-0.5)	(d)
1	**Year**			
2	2017	$88.33	0.9641	$ 85.16
3	2018	$90.98	0.8961	$ 81.53
4	2019	$93.71	0.8329	$ 78.05
5	2020	$96.53	0.7742	$ 74.73
6	2021	$99.42	0.7196	$ 71.54
7	2022	$102.40	0.6688	$ 68.49
8	2023	$105.48	0.6216	$ 65.57
9	2024	$108.64	0.5778	$ 62.77
10	Total			$ 587.84
11				
12	Levelized Generation Related Capacity Costs			$ 100.70
13				
14				
15				
16	**Notes:**			
17	(1) 2017$ Unless Otherwise Indicated.			
18	(2) Discount Rate		7.588%	
19				

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Transmission Plant Related Capacity Cost

Line	Description	Land	Poles & Towers	Conductors	Total	Peak Demand (KW)	$/KW
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Transmission Line Plant Cost**						
2	Transmission Additions By Year (1)						
3	2005	$0	$128,178	$30,164	$158,342	459,130	
4	2006	$0	$160,487	$84,122	$244,609	485,456	
8	2007	$32,275	$1,238,181	$358,303	$1,628,760	525,643	
9	2008	$30,133	$3,670,961	$3,743,956	$7,445,050	476,591	
10	2009	$5,158	$325,099	$170,521	$500,778	473,770	
11	2010	$0	$15,684	$9,474	$25,158	502,515	
12	2011	$0	$69,493	$133,227	$202,720	535,761	
13	2012	$1,465,095	$12,052,473	$4,819,090	$18,336,658	573,587	
14	2013	$0	$1,204,526	$887,543	$2,092,069	559,684	
15	Total	$1,532,662	$18,865,083	$10,236,399	$30,634,144		$442.84
16							
17							
18	**Total Transmission Plant Related Capacity Cost Per KW =**						$442.84
19							
20	**Notes:**						
20	(1) Source: PP 424 - 425 FERC Form 1						
20	(2) 2014 $						

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Marginal Transmission and Distribution Substation Plant Capacity Cost

Line	Description	MVA	Substation Cost	$ / kW
	(a)	(b)	(c)	(d) = c / b / 1000
1	Marginal Transmission Substation Plant			
2	Facility			
3	Dickinson West Junction (2014 $)	50	$ 5,591,682	$111.83
4	Ray Junction (2014 $)	40	$ 5,781,931	$144.55
5	Lignite Junction (2014 $)	40	$ 4,652,352	$116.31
6	Williston Little Muddy Junction (2014 $)	50	$ 5,433,884	$108.68
7	Total			$ 119.22
8	Marginal Distribution Substation Plant			
9	Facility			
10	Bismarck 26th St & Ave D Dist Sub (2014 $)	15	$ 1,876,950	$125.13
11	Williston Water Plant Dist Sub (2014 $)	5	$ 621,139	$124.23
12	Dickinson West Dist Sub (2014 $)	10	$ 879,660	$87.97
13	Epping Dist Sub (2014 $)	3.75	$ 595,195	$158.72
14	Total			$117.72
15				
16	**Notes:**			
18	2014 $			

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Distribution Plant Related Capacity Cost

Line	Description	Number of Customers	# Circuits	Customers per Circuit	OH Miles	UG Miles	OH $/Mile (1)	UG $/Mile (1)	Total ($/Customer)	Demand Related ($/Customer)	Customer Related ($/Customer)
	(a)	(b)	(c)	(d) = b/d	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Marginal Distribution Capacity Related Plant Cost - Lines										
2	Facility										
3	Glendive District	18,940	92	206	2,030.0	421.0	$ 37,537	$ 72,223	$ 5,628.62	$ 1,017.35	$ 4,611.27
4	Wolf Point District	6,743	50	135	899.0	153.0	$ 37,537	$ 72,223	$ 6,643.32	$ 1,217.14	$ 5,426.18
5	Total	25,683	142	181	2,929.0	574.0	$ 37,537	$ 72,223	$ 5,895.02	$ 1,069.80	$ 4,825.22
6											
7	Capacity related distribution line cost per NCP KW - Primary and Secondary (2)									$ 155.80	
8											
9											
10											
11									Number of Customers	Total Cost (1)	Cost per KW
12	Marginal Distribution Capacity Related Plant Cost - Transformers								(l)	(m)	(n)
13	Facility										
14	Single Phase Transformers								24,242	$ 320,964	$ 13.24
15	Three Phase Transformers								607	$ 9,572	$ 15.77
16	Capacity related distribution transformer cost per NCP KW @ meter - Secondary Only								24,849	$ 330,536	$ 13.30
17											
18											
19											
20											
21											Cost Per KW
22											(o) = line 7 column j + line 16 column n
23	Total Capacity Related Distribution Plant Costs Per NCP KW - Primary										$ 155.80
24	Total Capacity Related Distribution Plant Costs Per NCP KW - Secondary										$ 169.10
25											
26	**Notes:**										
27	(1) 2014 $										
30	(2) Total demand related cost per customer times total number of customers in Montana divided by Total NCP Load in Montana.										

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Customer Related Distribution (Lines and Transformers), Service Lines and Metering Plant Cost

Line	Description	Costs by Function, Plant Type and Rate Class (1)				
		Distribution		Service Lines, Metering, Meter Reading / Billing		
		Transformers FERC Account 368	Distribution Lines FERC Account 363-367	Services FERC Account 369	Meters FERC Account 370 (5)	Total Customer Plant
	(a)	(b)	(c)	(d)	(e)	(f) = b+c+d+e
1	Rate Class					
2	Residential Rate 10	$ 268.01	$ 4,825.22	$ 490.77	$ 88.13	$ 5,672.13
4	Small General Primary Rate 20	$ -	$ 4,825.22	$ -	$ 3,250.09	$ 8,075.31
5	Small General Secondary Rate 20	$ 896.29	$ 4,825.22	$ 574.72	$ 192.26	$ 6,488.49
6	General Space Heat Rate 32	$ -	$ -	$ -	$ 718.10	$ 718.10
7	Irrigation Power Rate 25	$ 2,708.38	$ 4,825.22	$ 881.05	$ 347.52	$ 8,762.17
10	Large General Primary Rate 30	$ -	$ 4,825.22	$ -	$ 5,466.60	$ 10,291.82
11	Large General Secondary Rate 30	$ 3,899.66	$ 4,825.22	$ 1,445.60	$ 969.78	$ 11,140.26
12	Large General Service TOD Rate 31- Secondary	$ 1,968.67	$ 4,825.22	$ 1,445.60	$ 969.78	$ 9,209.27
13	Large General Service TOD Rate 31- Primary	$ -	$ 4,825.22	$ -	$ 5,463.83	$ 10,289.05
14	Contract Services Rate 35	$ -	$ 4,825.22	$ -	$ 6,347.10	$ 11,172.32
15	Municipal Pumping Rate 48	$ 2,425.76	$ 4,825.22	$ 765.44	$ 378.33	$ 8,394.75
16	Outdoor Lighting Rate 52	$ 818.36	$ -	$ -	$ -	$ 818.36
17	Street Lighting Company Owned Rate 41	$ 818.36	$ 4,825.22	$ 330.31	$ 87.04	$ 6,060.93
18	Street Lighting Municipal Owned Rate 41	$ 818.36	$ 4,825.22	$ 330.31	$ 87.04	$ 6,060.93
19						
20	**Notes**					
21	(1) 2014 $					
22						
23						
24						
25						
26						

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Meter Reading, Customer Accounting, Service and Sales Expense Adders

	Description		2010		2011		2012		2013		2014
	(a)		(b)		(c)		(d)		(e)		(f)
1	Marginal Related Customer Accounts Expense (Current $)										
2	Supervision	$	31,690	$	25,589	$	35,068	$	16,249	$	15,727
3	Meter Reading Expense	$	156,143	$	150,470	$	128,362	$	89,989	$	85,610
4	Customer Records and Collection Exp.	$	390,288	$	427,174	$	401,037	$	486,095	$	501,715
5	Uncollectible Accounts	$	48,380	$	72,517	$	79,588	$	135,507	$	168,337
6	Misc. Customer Accounts Expense	$	29,019	$	27,959	$	21,292	$	46,961	$	49,994
7	Total Customer Accounts Expense	$	655,520	$	703,709	$	665,347	$	774,801	$	821,383
8	Marginal Related Customer Service & Info Expense (Current $)										
9	Supervision	$	10,642	$	10,814	$	7,614	$	12,248	$	10,616
10	Customer Assistance Expense	$	(6,614)	$	4,991	$	12,031	$	11,416	$	5,544
11	Informational and Instructional Expense	$	2,690	$	8,725	$	11,701	$	20,930	$	821,383
12	Misc. Customer Service & Info. Exp.	$	29	$	7	$	41	$	193	$	-
13	Total Customer Service & Info. Exp.	$	6,747	$	24,537	$	31,387	$	44,787	$	43,530
14	Marginal Related Sales Expense (Current $)										
15	Supervision	$	2,532	$	1,945	$	484	$	(70)	$	4
16	Demonstrating and Selling Expense	$	14,808	$	13,740	$	14,200	$	7,203	$	16,022
17	Advertising Expense	$	1,174	$	2,294	$	1,952	$	4,680	$	10,712
18	Misc. Sales Expense	$	6,008	$	5,254	$	5,006	$	3,339	$	3,017
19	Total Sales Expense	$	24,522	$	23,233	$	21,642	$	15,152	$	29,755
20	Marginal Cust Acct, Svc & Sales Expense (Current $)	$	686,789	$	751,479	$	718,376	$	834,740	$	894,668
21											
22	Handy-Whitman Factor for Distribution Plant		1.1615		1.1208		1.072		1.0323		1
23											
24	Marginal Cust Acct, Svc & Sales Expense (2014 $)	$	797,705	$	842,258	$	770,099	$	861,702	$	894,668
25											
26	Total Number of Customers		27,086		27,388		27,815		27,672		28,206
27											
28	5 Year Average (2014 $)	$	30.15								

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Marginal Cost Study

Meter Reading, Customer Accounting, Service and Sales Expense Adders

Line	Description	Marginal Unit Cost Per Customer				
		Meter Reading Expense	Customer Accounts Expense	Service & Info Expense	Sales Expense	Total
	(h)	(h) = h * class weight	(i) = i * class weight	(j) = j * class weight	(k) = k * class weight	(l) = h+i+j+k
1						
2	Marginal Unit Cost Per Customer	$ 4.82	$ 23.29	$ 1.15	$ 0.89	$ 30.15
3	Weighted Marginal Cost Per Customer Per Rate Class					
4	Residential Rate 10	$ 4.82	$ 23.29	$ 1.15	$ 0.89	$ 30.15
5	Small General Primary Rate 20	$ 7.23	$ 34.94	$ 1.73	$ 1.34	$ 45.24
6	Small General Secondary Rate 20	$ 6.27	$ 30.28	$ 1.50	$ 1.16	$ 39.21
7	General Space Heat Rate 32	$ 4.82	$ 23.29	$ 1.15	$ 0.89	$ 30.15
8	Irrigation Power Rate 25	$ 10.22	$ 49.37	$ 2.44	$ 1.89	$ 63.92
9	Large General Primary Rate 30	$ 14.17	$ 68.47	$ 3.38	$ 2.62	$ 88.64
10	Large General Secondary Rate 30	$ 13.69	$ 66.14	$ 3.27	$ 2.53	$ 85.63
11	Large General Service TOD Rate 31- Secondary	$ 22.03	$ 106.44	$ 5.26	$ 4.07	$ 137.80
12	Large General Service TOD Rate 31- Primary	$ 28.92	$ 139.74	$ 6.90	$ 5.34	$ 180.90
13	Contract Services Rate 35	$ 14.46	$ 69.87	$ 3.45	$ 2.67	$ 90.45
14	Municipal Pumping Rate 48	$ 8.72	$ 42.15	$ 2.08	$ 1.61	$ 54.56
15	Private Lighting Rate 52	$ 4.82	$ 23.29	$ 1.15	$ 0.89	$ 30.15
16	Street Lighting Company Owned Rate 41	$ 4.82	$ 23.29	$ 1.15	$ 0.89	$ 30.15
17	Street Lighting Municipal Owned Rate 41	$ 4.82	$ 23.29	$ 1.15	$ 0.89	$ 30.15
18						
19	**Notes:**					
20	(1) Actual Account Balances					
21	(2) Actual Customer Counts					
22	(3) Class Weights from Embedded Class Cost of Service Study					
23	(4) 2014 $ unless otherwise indicated					

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

Before the Public Service Commission of Montana

Docket No. D2015.6.___

Direct Testimony
of
Tamie A. Aberle

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

2 A. Yes. My name is Tamie A. Aberle, and my business address is 400
3 North Fourth Street, Bismarck, North Dakota 58501.

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

5 A. I am the Director of Regulatory Affairs for Montana-Dakota Utilities
6 Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

7 **Q. What are your responsibilities as the Director of Regulatory Affairs?**

8 A. I am responsible for the development and implementation of
9 Company objectives and policies with respect to rate structure, pricing
10 policies, cost of service studies, fuel cost adjustments, purchased gas cost
11 adjustments and gas tracking adjustments in each of the jurisdictions in
12 which Montana-Dakota operates.

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

15 A. I graduated from Moorhead State University, Moorhead, Minnesota
16 in 1982 with a Bachelor of Science degree in Accounting. I began my
17 career with Montana-Dakota in 1983 in the Regulatory Affairs Department,
18 holding several positions within the Department before attaining my
19 current position in 2014.

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

1 A. Yes. I have previously presented testimony before this
2 Commission, the Public Service Commissions of North Dakota and
3 Wyoming, and the Public Utilities Commissions of Minnesota and South
4 Dakota.
5 **Q. What is the purpose of your testimony in this proceeding?**
6 A. The purpose of my testimony is to present the effect of the
7 proposed revenue requirement, as identified by Mr. Jacobson in his direct
8 testimony, on each of the Company's electric rates, including how the
9 distribution of the revenue requirement was made among the various
10 classes of customers served. In addition, my testimony will discuss the
11 extent to which Montana-Dakota is proposing changes in rate design
12 and/or tariff conditions and the Company's proposed Environmental Cost
13 Recovery Rider and Transmission Cost Recover Rider.
14 **Q. What statements and exhibits are you sponsoring in this**
15 **proceeding?**
16 A. I am sponsoring pages 3-5 and page 8 of Statement H, Statement
17 M, Exhibit No.__(TAA-1) through Exhibit No.___(TAA-4) and the proposed
18 rate schedules to be effective on a final basis Appended to the
19 Application. I also sponsor pages 5-8 of Statement H, Statement M and
20 the proposed rate schedules appended to the Application for Interim Rate
21 Relief.
22 **Q. Please describe how the Company developed its pro forma sales**
23 **revenues for this case?**
24 A. The pro forma sales revenues are based on actual consumption for
25 the twelve month period ending December 31, 2014 adjusted to reflect the
26 annualized load for a new customer taking service under the Large

General Service Rate 30 schedule that started operations late in 2014. Revenues were then recalculated based on current rates and the updated base fuel costs that are presented by Mr. Jacobson.

Q. What is the total revenue effect of the proposed electric rate changes?

A. The proposed interim rates will produce additional revenues of $10,977,525 or an increase of 19.9 percent based on the interim level of test period sales, while the final proposed rates will produce additional revenues of $11,755,752 or an increase of 21.1 percent annually based on pro forma electric consumption and total revenues. Statement H, page 8 provides summaries by rate classification of the proposed final revenue increase. The schedule shows the rate class along with the revenues calculated under the present rates along with the proposed increase. The amount and percentage increase is also shown for the proposed revenue increase. A pictorial representation of the proposed revenue increase is set forth on Part B, Page 17 of Statement O. Statement H, page 8 within the Interim Application provides similar information.

<u>Revenue Allocation and Rate Design</u>

Q. What methodology did you use to apportion the proposed rate increase among the customer classes in this case?

A. A review of the embedded and marginal cost of service studies sponsored by Ms. Cardwell indicated that all of the rate classes are below the requested overall rate of return with the majority of the customers well below the requested overall return on rate base based on the embedded class study. Because of this and because of the magnitude of the overall increase I applied an equal percentage increase to all customer classes.

Q. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim revenue requirement of $10,975,511 was also applied on an equal percentage basis to all rate schedules. The Company is proposing to charge the interim increase of 19.93 percent as an equal percentage applicable to all rate schedules. The interim amount will be billed as a separate line item on the bill which will provide the ability for the Company to track the interim revenues collected from each customer. The calculations supporting the application of the interim increase to each class are provided in Statement M attached to the Application for Interim Increase in Electric Rates. The proposed tariff sheets reflecting the proposed interim increase are provided in Appendix A of the Application for Interim Increase in Electric Rates. As shown, the tariffs prescribe the interim increase as 19.93 percent of the amount billed under all components of the bill except the Universal System Benefits charge and the Kvar penalty where applicable. Page 1 of Exhibit No. ___ (TAA-1) shows the interim increase applied to each of the rate classes and Page 2 of Exhibit No. ___(TAA-1) shows a typical average residential bill reflecting the proposed interim increase.

Q. What is the percentage of the proposed final increase by class of customer?

A. As noted previously, the final increase was applied on an equal percentage basis to each of the rate classes. Page 1 of Exhibit No.___(TAA-2) shows the final increase in revenues by class of customers. Page 2 of Exhibit No.___(TAA-2) provides a typical average residential bill reflecting the proposed final increase in rates.

1 **Q. Have you prepared a reconciliation of the embedded revenue**
2 **requirement to the marginal cost study prepared by Ms. Cardwell?**
3 A. Yes. As noted by Ms. Cardwell, the system level marginal costs
4 are approximately 31% higher than the embedded cost revenue.
5 Therefore, reconciliation between the marginal costs and embedded costs
6 is necessary in order to utilize the marginal cost study. The reconciliation
7 is shown on Statement M, Page 2.
8 **Q. Would you please describe the rate form you are proposing for each**
9 **rate schedule and how you propose to collect the allocated final**
10 **increase from each of the rate schedules?**
11 A. Yes I will describe each rate schedule starting with Residential
12 Service Rate 10. The Basic Service Charge was increased to $0.25 per
13 day or $7.60 per month, an increase of $2.13 per month from the present
14 rate. This proposed charge is well below the customer component
15 supported in the embedded class study of $26.01 as shown on Statement
16 L, page 1 or the marginal customer cost component of $86.19 monthly as
17 provided by Ms. Cardwell on Page 3 of Exhibit No. ___(SJC-1). The
18 proposed Basic Service Charge provides a balance between reflecting the
19 true fixed costs of serving each customer and recognizing customer
20 impacts. The Basic Service Charge is collected on a daily basis in order
21 to avoid prorating the monthly charge when customers are in service less
22 than 30 days, on average, or when a billing period extends beyond a 30
23 day average. The energy charges for the residential rate schedule were
24 determined by reducing the total revenue responsibility for the class
25 (including the allocated revenue increase) by the revenues to be collected
26 under the proposed Basic Service Charge, the seasonal differential and

the pro forma Base Fuel and Purchased Power component for secondary service. The revenues remaining to be collected were divided by the pro forma Rate 10 Kwh sales to determine the cost per Kwh required to be collected through the energy component. A typical residential customer, using 808 Kwh on an annual basis, will see an annual increase in their electric service bill of $177.66 or $14.80 on a monthly basis as shown on Statement M, page 22.

The process described above for the calculation of the proposed Residential Rate 10 schedule was used to determine the rate components for each of the other rate schedules, that is, the first step was to establish the Basic Service Charge by considering the customer costs identified in the embedded cost of service study and the Demand Charge based on the demand costs identified in the embedded class cost of service study for those rate schedules where demand metering is warranted. The second step was to deduct the revenues to be recovered under the Basic Service Charge, Demand Charge, seasonal or service level differential and Base Fuel and Purchased Power components for each rate schedule. The Energy Charge component was then determined by dividing the revenues remaining to be collected by the pro forma sales under the applicable rate schedule. The calculations just described are provided for each rate schedule on pages 6-21 of Statement M and a summary of the proposed charges is provided on Statement M page 5.

Montana-Dakota continues to offer optional Time-of-Day (TOD) rate schedules consisting of Residential TOD Rate 16, Small General Service TOD Rate 26 and Large General Service TOD Rate 31. The rates have been designed to provide customers with an incentive to shift load to the

1 off-peak period (all hours except for the hours from noon to 8:00 p.m.
2 Monday through Friday).
3 A representation of the annual billing impact for each class is
4 provided on Pages 22-38 of Statement M.
5 **Q. Would you please describe the changes that the Company is**
6 **proposing to its Net Metering schedule Rate 92?**
7 A. Yes. As a result of the Commission's Order in Docket
8 No.D2007.7.79 Montana-Dakota has a net metering tariff in place that
9 provides customers utilizing distributed generation the opportunity to
10 utilize the Net Metering tariff wherein the difference between the electricity
11 supplied by the Company and electricity generated by an eligible
12 customer-generator and fed back to the electric grid is measured. Under
13 the Net Metering tariff, if the energy supplied by the Company exceeds the
14 customer generated energy, the energy charge per Kwh under the
15 otherwise applicable standard service tariff shall be applied to the positive
16 energy balance and charged to the customer. If the energy supplied by
17 the customer generator exceeds the amount of energy supplied by the
18 Company, the net Kwh is credited to the customer's next monthly bill and
19 used as a credit to offset customer use until consumption offsets the credit
20 or at the end of the designated 12-month billing period. This required
21 arrangement offers significant benefits to customers utilizing a form of
22 distributed generation. Not only are the customers with distributed
23 generation offsetting electric system grid costs by generating electric
24 energy for their own demand, it also provides a lucrative market for
25 electric energy produced during periods when the energy is not needed for
26 the customer's use which can result in significant subsidies to the

customers utilizing distributed generation at the expense of other utility customers. This is because net metering policies provide for customer-generated kWhs to be netted on a one-for-one basis with utility-delivered kWhs, essentially requiring the Company to pay consumers the retail price for wholesale power. That means the utility is paying for services typically included in retail rates that the consumer is not providing the utility, including distribution, transmission, utility operating and maintenance expenses and utility administrative and general expenses. These costs will generally be recovered from other consumers on the utility's system, leading to a cost shift from customer-generators to all other customers on the system.

Montana-Dakota is proposing to introduce a three-part residential rate in order to more accurately reflect the effect that net metering customers impose on the system. The proposal is to add a Demand Charge to the Net Metering Rate 92 at a charge of $1.50 per kW per month applicable to residential customers. The charge was derived based on the demand related costs identified for the residential class in the embedded class cost of service study and the non-coincident demand of the residential class. The proposed demand charge will address a portion of the inequities caused by net metering and reflect the fixed costs associated with providing service on demand to the customer. The Small General Service customers served under Rate 20 or 26 will be charged the otherwise applicable demand charge as well.

<u>New Cost Recovery Riders</u>

Q. Ms. Aberle, would you please explain the two cost recovery riders that the Company is proposing in this case?

1 A. Yes. The Company is proposing an Environmental Cost Recovery
2 Rider (ECRR) Rate 98 tariff and a Transmission Cost Recovery Rider
3 (TCRR) Rate 99 tariff as part of the proposed final tariff appended to the
4 Application that are also attached to my testimony and marked as Exhibit
5 No.__(TAA-3) and Exhibit No.___(TAA-4) respectively.
6 **Q. Please explain the Environmental Cost Recovery Rider Rate 98 tariff.**
7 A. The Environmental Cost Recovery Rider (ECRR) tariff specifies the
8 procedure to be used in recovering the jurisdictional costs incurred by
9 Montana-Dakota in complying with federal and state environmental
10 mandates. Costs to be recovered include a return on actual capital
11 expenditures, operating costs, depreciation and taxes not recovered in
12 rates established through a general rate case. The implementation of this
13 adjustment mechanism will provide customers the benefit of paying the
14 required costs on an incremental basis and a reduction in costs
15 associated with expensive rate cates while providing for timely recovery of
16 environmental mandates The ECRR will include an annual true-up from
17 the previous year based on actual expenditures. The true-up will be
18 reflected in the next ECRR adjustment filing. Note that the request at this
19 time is to establish the mechanism for future use in recovering applicable
20 expenditures and an adjustment is not proposed to be charged at this
21 time.
22 **Q. Please explain the Transmission Cost Recovery Rider Rate 99 tariff.**
23 The Transmission Cost Recovery Rider (TCRR) is proposed to
24 recover transmission investments and federally regulated transmission
25 related costs charged to the Company that are not part of the rates
26 established in this rate case. The TCRR is similar to the ECRR in that it

will recover costs on an on-going basis and providing for the timely reflection of actual transmission costs. As discussed by Mr. Neigum, evolving transmission system costs under various agreements along with variable MISO costs are more effectively covered through an adjustment mechanism because of the current volatility in such costs. The request for the TCRR is also to establish the mechanism for future use in recovering applicable expenditures and an adjustment is not proposed to be charged at this time.

<u>Changes to Rates 100 and 110</u>

Q. Would you please briefly describe other changes made to the Company's electric tariff?

A. Yes. The Company is proposing minor wording changes to Rate 100 and is proposing to modify the Reconnection Fee for Seasonal Customers. Currently the Company charges $20 for all reconnections for seasonal customers. However, it is more time consuming to reconnect a customer with a demand meter so the Company is proposing that the charge be $40 for seasonal reconnections for customers with demand meters.

Rate 110 is modified as follows:

- Section 101 is now Purpose not Definitions.
- Section 102 is now Definitions not Purpose.
- Section 103 has been modified to better reflect the Company's deposit requirement and access needs by the Company for such things as meter maintenance.

- Section 104 Liability is modified to state that it is the customer's obligation to consult with the Company regarding fault current and protection devices.
- Section 207 which discusses Overhead to Underground Primary Conversions has been added.
- Section 600 is updated to better describe meter requirements.
- The Company is also proposing to update its figures which appear at the end of this rate schedule which includes adding Figure 6 which shows the typical transition cabinet installation.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Allocation of Revenues - Interim
Pro Forma 2015

Customer Class	Kwh	KW	Base Rate	Energy	Demand	F&PP	Total	Revenue Increase $	Revenue Increase %
Residential Service	195,240,541		$1,318,205	$10,592,715	$0	$4,869,299	$16,780,219	$3,344,298	19.9%
Small General Service	131,355,359	336,537.2	1,155,383	4,119,433	1,850,131	3,275,976	10,400,923	2,072,904	19.9%
Large General Service	461,236,713	943,007.6	273,156	8,024,367	7,085,100	11,163,095	26,545,718	5,290,562	19.9%
Municipal Pumping	7,341,210	31,456.4	28,638	143,227	103,656	183,090	458,611	91,401	19.9%
Lighting	10,135,735			642,144		252,785	894,929	178,360	19.9%
Total Montana Electric	**805,309,558**	**1,311,001.2**	**$2,775,382**	**$23,521,886**	**$9,038,887**	**$19,744,245**	**$55,080,400**	**$10,977,525**	**19.9%**

Docket No. _____
Exhibit No. _____ (TAA-1)
Page 1 of 2

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Residential Electric Service Rate 10
Interim Bill Comparison Worksheet

		Current Rates				Proposed Interim Rates					Bill Change	
	Kwh	Basic Service Charge	Energy	F&PP	Total	Basic Service Charge	Energy	F&PP	Interim	Total	$ Increase	% Increase
January	1,100	$5.47	$52.98	$28.14	$86.59	$5.47	$52.98	$28.14	$17.26	$103.85	$17.26	19.9%
February	1,000	5.47	48.16	25.58	79.21	5.47	48.16	25.58	15.79	95.00	15.79	19.9%
March	1,000	5.47	48.16	25.58	79.21	5.47	48.16	25.58	15.79	95.00	15.79	19.9%
April	800	5.47	38.53	20.46	64.46	5.47	38.53	20.46	12.85	77.31	12.85	19.9%
May	650	5.47	31.30	16.63	53.40	5.47	31.30	16.63	10.64	64.04	10.64	19.9%
June	600	5.47	40.88	15.35	61.70	5.47	40.88	15.35	12.30	74.00	12.30	19.9%
July	700	5.47	47.69	17.91	71.07	5.47	47.69	17.91	14.16	85.23	14.16	19.9%
August	900	5.47	61.32	23.02	89.81	5.47	61.32	23.02	17.90	107.71	17.90	19.9%
September	750	5.47	51.10	19.19	75.76	5.47	51.10	19.19	15.10	90.86	15.10	19.9%
October	600	5.47	28.90	15.35	49.72	5.47	28.90	15.35	9.91	59.63	9.91	19.9%
November	650	5.47	31.30	16.63	53.40	5.47	31.30	16.63	10.64	64.04	10.64	19.9%
December	950	5.47	45.75	24.30	75.52	5.47	45.75	24.30	15.05	90.57	15.05	19.9%
Total	9,700	$65.64	$526.07	$248.14	$839.85	$65.64	$526.07	$248.14	$167.39	$1,007.24	$167.39	19.9%
Average	808	$5.47	$43.84	$20.68	$69.99	$5.47	$43.84	$20.68	$13.95	$83.94	$13.95	19.9%

Rate 10 Current		
Basic Service Charge	$0.18	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.06813	per Kwh
Winter Kwh (Oct-May)	$0.04816	per Kwh
Fuel & Purchased Power	$0.02558	per Kwh

Rate 10 Proposed Interim		
Basic Service Charge	$0.18	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.06813	per Kwh
Winter Kwh (Oct-May)	$0.04816	per Kwh
Fuel & Purchased Power	$0.02558	per Kwh

Interim increase 19.93% of total bill

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Revenues at Proposed Rates
Pro Forma 2015

	Pro Forma Billing Determinants & Revenues									
Customer Class	Kwh	KW	Base Rate	Energy	Demand	Fuel Rev	Total Revenue Before Increase	Total Proposed Revenue	Revenue Increase	% Incr
Residential Service	195,240,541		$1,318,205	$10,592,715	$0	$4,994,253	$16,905,173	20,479,180	$3,574,007	21.1%
Small General Service	131,355,359	336,537.2	1,155,383	4,119,433	1,850,131	3,360,063	10,485,010	12,702,039	2,217,029	21.1%
Large General Service	461,236,713	943,007.6	273,156	8,024,367	7,085,100	11,467,284	26,849,907	32,526,113	5,676,206	21.1%
Municipal Pumping	7,341,210	31,456.4	28,638	143,227	103,656	187,788	463,309	561,242	97,933	21.1%
Lighting	10,135,735			642,144		259,271	901,415	1,091,992	190,577	21.1%
Total Montana Electric	**805,309,558**	**1,311,001.2**	**$2,775,382**	**$23,521,886**	**$9,038,887**	**$20,268,659**	**$55,604,814**	**$67,360,566**	**$11,755,752**	**21.1%**

Docket No. _____
Exhibit No. _____ (TAA-2)
Page 1 of 2

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Residential Electric Service Rate 10
Bill Comparison Worksheet

		Current Rates				Proposed Rates				Bill Change	
	Kwh	Basic Service Charge	Energy	F&PP	Total	Basic Service Charge	Energy	F&PP	Total	$ Increase	% Increase
January	1,100	$5.47	$52.98	$28.14	$86.59	$7.60	$70.22	$28.14	$105.96	$19.37	22.4%
February	1,000	5.47	48.16	25.58	79.21	7.60	63.84	25.58	97.02	17.81	22.5%
March	1,000	5.47	48.16	25.58	79.21	7.60	63.84	25.58	97.02	17.81	22.5%
April	800	5.47	38.53	20.46	64.46	7.60	51.07	20.46	79.13	14.67	22.8%
May	650	5.47	31.30	16.63	53.40	7.60	41.50	16.63	65.73	12.33	23.1%
June	600	5.47	40.88	15.35	61.70	7.60	50.29	15.35	73.24	11.54	18.7%
July	700	5.47	47.69	17.91	71.07	7.60	58.67	17.91	84.18	13.11	18.4%
August	900	5.47	61.32	23.02	89.81	7.60	75.43	23.02	106.05	16.24	18.1%
September	750	5.47	51.10	19.19	75.76	7.60	62.86	19.19	89.65	13.89	18.3%
October	600	5.47	28.90	15.35	49.72	7.60	38.30	15.35	61.25	11.53	23.2%
November	650	5.47	31.30	16.63	53.40	7.60	41.50	16.63	65.73	12.33	23.1%
December	950	5.47	45.75	24.30	75.52	7.60	60.65	24.30	92.55	17.03	22.6%
Total	9,700	$65.64	$526.07	$248.14	$839.85	$91.20	$678.17	$248.14	$1,017.51	$177.66	21.2%
Average	808	$5.47	$43.84	$20.68	$69.99	$7.60	$56.51	$20.68	$84.79	$14.80	21.1%

Rate 10 Current

Basic Service Charge	$0.18	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.06813	per Kwh
Winter Kwh (Oct-May)	$0.04816	per Kwh
Fuel & Purchased Power	$0.02558	per Kwh

Rate 10 Proposed

Basic Service Charge	$0.25	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.08381	per Kwh
Winter Kwh (Oct-May)	$0.06384	per Kwh
Fuel & Purchased Power	$0.02558	per Kwh

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of Montana
Electric Rate Schedule

Volume No. 4
Original Sheet No. 50

ENVIRONMENTAL COST RECOVERY RIDER Rate 98

1. Applicability:

This rate schedule represents an Environmental Cost Recovery Rider (ECRR) and specifies the procedure to be utilized to recover the jurisdictional costs to be incurred by the Company in complying with federal and state environmental mandates. Costs to be recovered may include capital expenditures and operating costs. Costs being recovered under this tariff are currently not included in the rates established at the time of the Company's last general rate case.

2. Environmental Cost Recovery Rider:

a. An adjustment per Kwh will be calculated using the projected capital costs and related expenses, along with the forecasted Kwh sales, to determine a Montana jurisdictional revenue requirement to be recovered through the ECRR. The return component of the revenue requirement calculation will be the authorized rate of return from the Company's most recent general rate case.

b. The ECRR is applicable to all retail customers for electric energy sold, except those served under special contracts, and are allocated amongst the rate classes based on the Company's AED Factor No. 2 established in the Company's most recent general rate case.

c. The ECRR will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses.

d. A true-up will reflect any over or under collection of revenue under the ECRR based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. Time and Manner of the Filing:

Montana-Dakota shall file the annual ECRR at least 30 days prior to the proposed effective date. The filing by Montana-Dakota shall be made by means of a revised ECRR tariff sheet identifying the amounts of the adjustment, the derivation of the ECRR and the resulting ECRR by class.

Issued: June 24, 2015 **By:** Tamie A. Aberle
Director – Regulatory Affairs

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Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of Montana
Electric Rate Schedule

Volume No. 4
Original Sheet No. 50.1

ENVIRONMENTAL COST RECOVERY RIDER Rate 98

4. Environmental Cost Recovery Rider:

Residential and Small General	0.000¢ per Kwh
Large General	0.000¢ per Kwh
Lighting	0.000¢ per Kwh

Issued: June 24, 2015

By: Tamie A. Aberle
Director – Regulatory Affairs

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400 N 4th Street
Bismarck, ND 58501

State of Montana
Electric Rate Schedule

Volume No. 4
Original Sheet No. 51

TRANSMISSION COST RECOVERY RIDER Rate 99

APPLICABILITY:

This rate schedule represents a Transmission Cost Recovery Rider (TCRR) and specifies the procedure to be utilized to recover the capital and operating costs associated with transmission related investments and expenditures. Costs to be recovered under the TCRR shall include new or modified transmission facilities such as transmission lines and other transmission related equipment such as substations, transformers and other equipment constructed to improve the power delivery capability or reliability of the transmission system as well as federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability that are not reflected in the rates established in the most recent general rate case.

TRANSMISSION COST RECOVERY RIDER:

a. An adjustment per Kwh will be determined based on the cumulative transmission related costs eligible for recovery and as allocated to the Montana jurisdiction as of September 30 of each year and the projected Kwh sales for the recovery period. The adjustment will also include a return requirement on the capital investments based on the authorized rate of return and a true-up of the previous year's adjustment, as described in 2(d).

b. The adjustment will be applicable to all retail customers for electric energy sold.

c. The adjustment per Kwh will be revised annually to reflect the current level of expenditures.

d. The true-up will reflect any over or under collection of revenue under the TCRR from the preceding twelve month period plus carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of Montana
Electric Rate Schedule

Volume No. 4
Original Sheet No. 51.1

TRANSMISSION COST RECOVERY RIDER Rate 99

TIME AND MANNER OF FILING:
Montana-Dakota shall file the TCRR adjustment at least 30 days prior to the proposed effective date. The filing by Montana-Dakota shall be made by means of a revised TCRR tariff sheet identifying the amounts of the adjustment, the derivation of the adjustment and the resulting TCRR rate.

TRANSMISSION COST RECOVERY RIDER (TCRR):

TCRR per Kwh = 0.000¢

Issued: June 24, 2015 **By:** Tamie A. Aberle
Director – Regulatory Affairs

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