

**STATE OF NORTH DAKOTA**  
**PUBLIC SERVICE COMMISSION**

**Montana-Dakota Utilities Co.,  
a Division of MDU Resources Group, Inc.  
2016 Electric Rate Increase  
Application**

**Case No. PU-16-666**

**AFFIDAVIT OF SERVICE BY REGULAR MAIL**

STATE OF NORTH DAKOTA  
COUNTY OF BURLEIGH

**Geralyn R. Schmaltz** deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **27th day of February, 2017**, she deposited in the United States Mail, Bismarck, North Dakota, **6** envelopes by regular mail, with postage fully prepaid, securely sealed, each containing a photocopy of:

- **Direct Testimony of Sara Cardwell**
- **Direct Testimony and Exhibits of Richard A. Polich, P. E.**
- **Direct Testimony and Exhibits of Jacob M. Thomas, P.E.**

The envelopes were addressed as follows:

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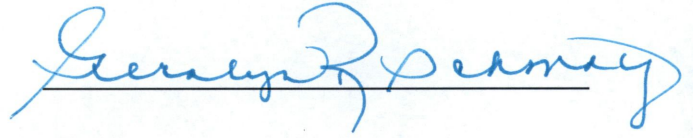
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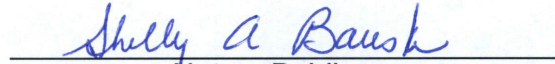
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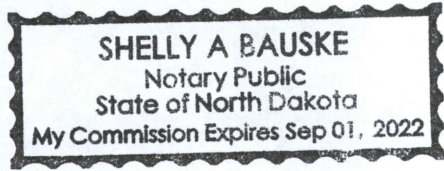
PSC Case No. PU-16-666  
Affidavit of Service  
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February 27, 2017

Each email address is the respective addressee's last reasonably ascertainable electronic mailing address.

Subscribed and sworn to before me  
this **27th** day of **February, 2017**.

  
\_\_\_\_\_

  
\_\_\_\_\_  
Notary Public



SEAL

**BEFORE THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

***In the Matter of Montana-Dakota Utilities Co.,  
A Division of MDU Resources Group, Inc.***

***2016 Electric Rate Increase***

***Application***

***Case No. PU-16-666***

**DIRECT TESTIMONY  
OF  
SARA CARDWELL**

**ON BEHALF OF THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION  
ADVOCACY STAFF**

**February 24, 2017**

1 **Q: Provide your name and qualifications.**

2 A: My name is Sara Cardwell. I am a Public Utility Analyst with the North Dakota  
3 Public Service Commission (Commission). I have more than 35 years of  
4 utility regulatory experience. In addition to working for the Commission, I  
5 have worked for PacifiCorp, Portland General Electric Company, Xcel Energy  
6 and Montana-Dakota Utilities Co.

7 I received a Bachelor of Science Degree in Business Administration from the  
8 University of Wisconsin-Stout and received my Masters in Business  
9 Administration from the University of Portland. I have testified before this  
10 Commission as well as the Public Service Commission of Montana, the  
11 California and Idaho Public Utilities Commissions, the Oregon Public Utility  
12 Commission and the Washington Utilities and Transportation Commission.

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

14 A: The Commission appointed me to Advocacy Staff (Staff) in this proceeding.  
15 As such, I will present recommendations on a variety of issues in regards to  
16 changes the Commission should consider in order to improve the Company's  
17 ratemaking process. The resolution of these issues will improve the  
18 ratemaking process, streamline filings and result in improved understandings  
19 between the Staff and the Company. Some of these issues have been  
20 discussed with the Company previously, but need Commission action in order  
21 to implement changes.

22 **Q: Please provide a brief summary of the issues you will address.**

23 A: I will address the following issues:

- 24 1. Off-Peak Demand Charges;
- 25 2. Interest rates on deposits;
- 26 3. Billing demand based on 15 minute rolling intervals;
- 27 4. Meter Data Management Systems;
- 28 5. Employee/Retiree discounts;
- 29 6. Contract Rates;

- 1           7. The time and manner of filings section in rider tariffs; and
- 2           8. The Company's Fuel and Purchased Power Adjustment Rate 58
- 3           pricing and filings.

4

5   **Q: What are the issues with off-peak demand charges?**

6   **A:** In this case, the Company is proposing to add a \$2.00 per Kw Off-Peak  
7   Demand charge to Schedule 31 for when the customer's demands during the  
8   off-peak period exceed the customer's on-peak demand. While there are  
9   reasons for having an off-peak demand charge in excess of the on-peak  
10   charge, there are also reasons why this is not a good idea. In general,  
11   utilities should encourage customers to peak during off-peak periods.  
12   Instituting such a charge can discourage customers from moving certain  
13   business operations to the off-peak period. However, on the flip side, if we  
14   were seeing customers installing demand control devices and/or on-site  
15   generation that was lowering demands in the on-peak period but not in the  
16   off-peak period, this charge would have some merit. To date, demand control  
17   devices and on-site generation to lower on-peak demands do not seem to be  
18   in use in North Dakota.

19

20   There has not been a clear purpose explained for this proposed change. In  
21   Data Request Response 1.35, the Company stated: "Charging for the  
22   increment above the on-peak recognizes that capacity related costs also exist  
23   in the off peak and the charge provides cost recovery for those costs at a cost  
24   much less than the on-peak charge. The customer moving a higher  
25   percentage of demand to the off-peak will pay less than if the customer were  
26   to maintain that load in the on-peak hours."

27

28   In asking further about this charge, the Company stated in their response to  
29   4.4:

1           “The off-peak demand charge is a recognition of the distribution  
2           demand costs that were previously recovered through the energy  
3           charge.”  
4

5           In response to 7.1 the Company stated that “The off-peak demand charge of  
6           \$2.00 represents a contribution toward the demand costs identified for the  
7           class that are not recovered through the on-peak demand charge.”  
8

9           Seeing that the Company has provided three different reasons for proposing  
10          this charge that don’t match up, Staff is concerned that the Company  
11          proposed this change without really thinking the issue through. In looking at  
12          the customer data, there only appears to be one customer that has  
13          substantial off-peak demands in excess of on-peak demands. The Company  
14          should find out why this particular customer is using more off-peak rather than  
15          implementing a charge to provide a disincentive to the entire customer class.  
16          Furthermore, if the on-peak demand charges are not cost based, then  
17          instituting a demand charge for the off peak demand that should really be  
18          assigned to on-peak period is not the correct price signal.  
19

20          The Company has 6,684 secondary voltage level customers on Rate  
21          Schedule 30 and 68 secondary voltage level customers on Rate Schedule 31  
22          yet it is not proposing this charge for Schedule 30. One would think that with  
23          the larger number of customers, there would be more of a need for an off-  
24          peak demand charge on Rate Schedule 30. Additionally, this proposal will  
25          recover less than one percent of the revenue assigned to Rate Schedule 31,  
26          meaning there is little benefit to this charge.  
27

28          The Company is also planning on lowering its Basic Customer Charge to this  
29          customer group. In summary, Staff recommends the Company’s proposal to  
30          institute an off-peak demand charge should be rejected. A better approach to

1 solving what might be the Company's real issue would be to keep the  
2 customer charge at its current level and consider further increases to the on-  
3 peak demand charge.

4

5 **Q: Please explain Staff's concern with the interest rate on deposits.**

6 A: Utilities in North Dakota are allowed to collect a deposit from customers when  
7 there is a concern that the customer may be a credit risk. The utilities are  
8 required to calculate interest on this deposit amount so that if the customer  
9 proves themselves not to be a credit risk after 12 months the deposit plus  
10 interest is returned to customers. The interest rate on the deposits is updated  
11 annually based on the Bank of North Dakota's interest rate on a six-month  
12 Certificate of Deposit. Montana-Dakota has a "Fly Sheet" as part of their tariff  
13 that indicates this interest rate. However, customers normally do not look at  
14 tariffs and generally don't even know what they are.

15

16 Staff asked the Company how a customer is informed as to the interest rate.

17 The Company responded:

18

19 "When discussing the need for a deposit with the customer, the  
20 customer service representative informs them that the deposit will be  
21 held on their account for 12 months, and after 12 months of good  
22 payment history, the deposit will be returned to the customer, plus any  
23 interest earned. The rate of interest is provided upon request."

24

25 The customer should not have to request information on the interest rate.  
26 The customer service representative should be instructed to provide this  
27 information in all cases. Furthermore, to ensure that customers are  
28 adequately informed, the Company website should provide information as to  
29 what is involved to become a customer including when a deposit is required  
30 and what the interest rate is on that deposit.

1

2 **Q: Why do you recommend that the Company move to using rolling**  
3 **demands for billing customers?**

4 A: In this day and age, with all the computer, metering, meter reading and billing  
5 system advances, the use of rolling demands for the billing of customers is a  
6 convenient and fair way to ensure that customers are being billed correctly. It  
7 is interesting that a Company that believes off-peak demand billing is  
8 necessary would state it doesn't believe there are customers on the system  
9 that are peak splitters so rolling demand intervals are unnecessary. In reality,  
10 peak splitters are a bigger issue for utilities than off-peak system users.

11

12 It is important to understand how a rolling demand interval works. Currently  
13 Montana Dakota bills customers based on the highest averaged 15-minute  
14 demand interval that occurs during the billing month. The 15 minute periods  
15 being used start on the hour, then the next fifteen minute period starting at 15  
16 minutes after the hour, then 30 minutes after the hour begins, etc. A rolling  
17 demand still covers a 15-minute period but that 15 minute period reading  
18 occurs every 5 minutes. Thus, the customer is billed on the highest 15-  
19 minute demand occurring over any 15-minute period. This means that a  
20 customer that might currently be starting up machinery say at 10:13 am and  
21 shutting it down at 10:17 am in order that the start-up and shut down occurs  
22 over two read cycles can no longer split its loads over two periods. With  
23 rolling demands, this customer will see a more accurate bill that reflects the  
24 customer's actual costs to the system. Xcel Energy and Otter Tail Power bill  
25 on rolling demand intervals and many other utilities do as well.

26

27 **Q: Is this something that you recommend the Company do as a result of**  
28 **this rate case?**

29 A: It takes time for a Company to make such a change. Staff's recommendation  
30 is that the Company study moving to rolling demand intervals as part of

1 research into a meter data management system. Staff asserts the Company  
2 should develop a concrete implementation timeline for moving to using rolling  
3 demand intervals for billing either as part of a meter data management  
4 system or separately before or as part of the Company's next rate case.

5

6 **Q: Please describe what a meter data management system is.**

7 **A:** When utilities first started implementing automated meter reading systems,  
8 the goal was to have data available to help utilities, customers and regulators  
9 better know the customers and how they use electricity. But, for many  
10 utilities, including Montana-Dakota, all the daily read information just sits  
11 unused while customers pay for a system that doesn't furnish any better data  
12 than when meters were read monthly by meter readers. And, depending on  
13 the rural versus urban nature of the utility, customers might see lower costs if  
14 meter readers were still reading meters.

15

16 In summary, customers are currently paying for a system that does not  
17 provide them, the Company or regulators with the informational benefits that  
18 were claimed as the reason an automated reading system was necessary in  
19 the first place. With the ability to access daily read data, the Company can  
20 employ advanced billing and pricing concepts such as rolling demand  
21 intervals or residential demand charges. The Company would also be able to  
22 provide customers with better information as to when they use electricity and  
23 how they might better control bills.

24

25 So, in addition to Staff's recommendation regarding billing demand based on  
26 rolling demand intervals, Staff recommends the Company implement a meter  
27 data management system prior to filing its next rate case so it can engage in  
28 serious rate design discussions.

29

1 **Q: Please describe your concerns with the Company's employee**  
2 **discounts.**

3 A: Section 10 of the Company's Rate Schedule 100 discusses discounts for  
4 qualifying employees. In response to Data Request 4.9 the Company stated  
5 that discounts are only provided to retirees that retired on or before December  
6 31, 2009. In order to eliminate confusion, the Company should be required to  
7 change the language of this section of their tariff to clearly state that the  
8 discounts are only provided to this group of retirees.

9

10 **Q: Please identify the Company's contract rates.**

11 A: While the Company may have customers sign standard service agreements,  
12 Staff's concern is not with standard service agreements. Our concerns are  
13 with the Company's contracts for discounted pricing. There are three  
14 customers on Rate 30 Contract Rates, three customers on Rate 38  
15 Interruptible Service and one customer on what the Company calls Rate 39  
16 Interruptible Large Power Service. (The Company does not actually have a  
17 tariff schedule entitled Rate 39.) The Company also has a rate schedule  
18 entitled Firm Service Economic Development Rate 34 under which a  
19 customer receives discounts that gradually decrease over the five-year  
20 contract period.

21

22 **Q: Please describe Staff's concern with Firm Service Economic**  
23 **Development Rate 34.**

24 A: Staff's concern is that the Company has proposed removing the following  
25 language from the tariff: "Contracts shall be filed with and approved by the  
26 North Dakota Public Service Commission." The Company did not state any  
27 reasons why it wants this provision removed in its direct testimony but did  
28 respond to a discovery request. Staff asserts that these contracts should  
29 continue to be reviewed.

30

1 **Q: Why does Staff assert contract review is necessary?**

2 **A:** As per the orders approving discount rate contracts in the past, the Company  
3 reports the contract delta associated with its contracts every year in its annual  
4 report. The table below shows the contract deltas since 2009:

2009	\$	620,240.00
2010	\$	505,930.00
2011	\$	543,909.00
2012	\$	606,617.00
2013	\$	621,790.00
2014	\$	1,060,777.61
2015	\$	1,318,511.76
2016	\$	2,287,255.51

5

6

7 As shown in the table above, the deltas took a dramatic leap in 2014 and  
8 have continued to grow significantly in the last few years. Absent the special  
9 contracts, the Company's request in this case might have been less. The  
10 Company has a responsibility to consider all ratepayers. If the same  
11 contracts remain in effect for a number of years without review, it is not a  
12 given that the discounts remain reasonable.

13

14 The most recent order for a special contract Electric Service Agreement was  
15 issued in 2007. The order in that case stated, "At the time of MDU's next  
16 electric rate increase request or rate review proceeding, the Commission will  
17 review MDU's overall revenue requirements and will specifically review the  
18 revenue impact resulting from special contracts." While there was some level  
19 of review in the 2010 case, the Company did not provide information in this  
20 case that would allow for Staff review of these contracts in this case. The  
21 contracts appear to have an initial term of 5 years and then are automatically  
22 renewed until either party decides a change is needed. With the exception of  
23 one contract, each of these special contracts currently in effect have been in  
24 effect for longer than five years without modification.

25

1           When asked in Data Request 8.2, the Company stated the contracts are now  
2           under review. The Company needs to provide justification to the Commission  
3           as to why the existing special contracts are still appropriate. If Staff is not  
4           involved in the approval of contracts going forward, the Company may  
5           negotiate contracts that are not in the best interests of all ratepayers and  
6           keep contracts in place for longer than may be appropriate. Because it  
7           appears the Company has begun a review of these contracts, Staff  
8           recommends that the Commission require the Company to file its justification  
9           and terms for each of the special contracts currently in effect and explain why  
10          the contracts and terms are still appropriate or file a revised contract. Staff  
11          will review the Company's information and, or revised contracts and present  
12          recommendations to the Commission regarding each contract.

13  
14       **Q: Please describe Staff's concern with the Company's "Time and Manner**  
15       **of the Filing" section on each of its rider schedules.**

16       **A:** The Commission regulates three investor owned utilities in this state that  
17       provide electric service. Each of these utilities has riders in place. Each of  
18       these utilities files a monthly fuel clause adjustment which is not at issue here.  
19       Our concern relates to the annual rider updates. Two of the electric utilities,  
20       Otter Tail and Xcel Energy, file their annual rider updates providing Staff with  
21       a three to four months review period.

22  
23       Montana-Dakota files its annual rider updates presuming the Staff can  
24       complete its review in 30 to 60 days. The Company states in the Time and  
25       Manner of the Filing section of its rider tariffs that the Commission is allowed  
26       a 30 or 60 day review period, depending on the rate schedule. Staff  
27       requested the Company remove this section from their rider tariffs as it is  
28       difficult to accomplish a review in this short period of time. Note that the need  
29       for more time isn't based on just Staff's need but, the entire review process  
30       which includes issuing notice requirements and scheduling an informal or

1 formal hearing. The Company also needs to provide notice to customers in  
2 their bills that it has made a filing which requires a month in order that the  
3 notice be sent out in each of the monthly billing cycles.

4  
5 Based on Staff's experience, it is difficult to process these cases in less than  
6 90 days. In response to the Staff's data request on this issue, the Company  
7 stated:

8 "the preference would be to not exceed 60 days for annual updates  
9 to existing rate riders. The inclusion of 60 days provides for the  
10 availability of the most recent costs and/or projections be included  
11 in the proposed rates. The further the minimum number of days is  
12 extended the less actual cost and known variables are included and  
13 replaced with projections of those variables."

14  
15 Note that all three utilities are allowed to include true-ups each year for  
16 differences in actuals versus what was filed the previous year so the  
17 Company's stated basis for such a short review period is not critical. Staff  
18 has not noticed problems with the longer review period allowed by Xcel  
19 Energy and Otter Tail Power. Staff requests the Company remove this  
20 section from each of its rider tariffs and provide for a minimum 90-day review  
21 period.

22  
23 **Q: Does the Staff have recommended changes for the Company's Fuel and**  
24 **Purchased Power Adjustment Rate 58?**

25 **A:** The Staff has a number of recommended changes which are as follows:

- 26
- 27 • Rather than the monthly filing being based on a change from the Base  
28 Fuel and Purchased Power costs approved in a general rate case, the  
29 monthly filings should be based on the total applicable costs for the  
30 month. This will make the filing consistent with the amount shown on  
the customer's bill and reduce potential errors by eliminating the need

1 to calculate the billing rate as base costs plus or minus the monthly  
2 change.

- 3 • Eliminate the monthly changes to the tariff. Montana-Dakota is the  
4 only utility of the three North Dakota regulated electric utilities that files  
5 a tariff as part of their monthly update. The other two utilities provide  
6 tables on their websites where the monthly fuel cost are easy to find.  
7 Montana-Dakota files a tariff and the only way a customer can find the  
8 costs are to find the tariff, then add or subtract the amount on the tariff  
9 from the amount on the applicable rate schedule. Having a convenient  
10 table on the website versus a monthly tariff reduces regulatory impact,  
11 improves customer understanding and will eliminate the need for the  
12 Commission to return proof of receipt of the tariff change to the  
13 Company.
- 14 • Exclude MISO Schedule 24 charges from the Fuel and Purchased  
15 Power costs. Neither Xcel Energy nor Otter Tail include these costs in  
16 their monthly fuel costs. This is a MISO administrative cost. MN  
17 determined because it is an administrative cost, it should be included  
18 as part of the utilities' base rates similar to other administrative costs.  
19 Additionally, MN determined by excluding this cost from the fuel costs,  
20 the utilities have a greater incentive to encourage MISO to keep its  
21 administrative costs in check.

22  
23 Montana-Dakota argues that the Schedule 24 costs change monthly,  
24 they should be considered part of the fuel costs and they shouldn't  
25 have to do what the other two utilities are doing. These arguments are  
26 not persuasive. Administrative costs do not belong in the fuel cost  
27 adjustment. By excluding these costs from the fuel costs, we can  
28 provide an incentive for utilities to work with MISO to ensure their  
29 administrative charges are reasonable and prudent. Staff would also

1           like to see more consistency across the utilities in the monthly fuel cost  
2           adjustment filings.

- 3           • Another way to improve consistency is if all the utilities true-up their  
4           fuel cause adjustments on a monthly basis. Currently Otter Tail and  
5           Xcel Energy employ a monthly true-up. Montana-Dakota performs an  
6           annual true-up. Staff does not see that a monthly true-up adversely  
7           affects the costs to customers. In fact, it may actually help customers  
8           as a large positive or negative balance does not occur with this  
9           method. Therefore, Staff recommends that Montana-Dakota change to  
10          a monthly true-up versus an annual true-up. As part of its compliance  
11          filing to implement the final rates in this case, the Company should  
12          provide information as to the best timing to change from an annual to a  
13          monthly true-up.

14  
15   **Q: Please summarize your recommendations.**

16   **A: The Staff's recommendations are:**

- 17           1. Montana-Dakota's proposal for an Off-peak Demand Charge and a  
18           decrease to the Basic Service Charge on Schedule 31 should be  
19           rejected;
- 20           2. The Company shall add information to its website in a clearly marked  
21           fashion regarding when customers are required to pay deposits and  
22           what the interest rate on deposits is;
- 23           3. The Company shall propose changing to billing demand based on 15-  
24           minute rolling intervals in its next rate case;
- 25           4. The Company shall institute a Meter Data Management System before  
26           its next rate case;
- 27           5. The Company shall modify Section 10 of Rate Schedule 100 to state  
28           that the discount is only available to retirees that retired on or before  
29           December 31, 2009;

- 1           6. The Company shall file its justification, or new contracts, for all of its  
2           special contracts within the next six months for further Commission  
3           review;
- 4           7. The Company shall eliminate the time and manner of filings section in  
5           rider tariffs and file its annual rider updates to allow for a minimum 90-  
6           day review period; and
- 7           8. The Company shall modify its Fuel and Purchased Power Adjustment  
8           Rate 58 pricing and filings as stated above.

9

10 **Q: Does this conclude your testimony?**

11 **A: Yes, it does.**

STATE OF NORTH DAKOTA

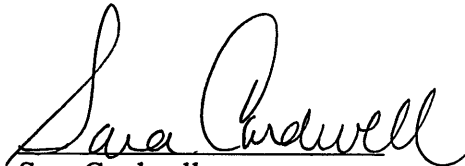
BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of  
MONTANA-DAKOTA UTILITIES CO.,  
A Division of MDU Resources Group, Inc.  
for authority to Increase Rates for Electric Service in North Dakota

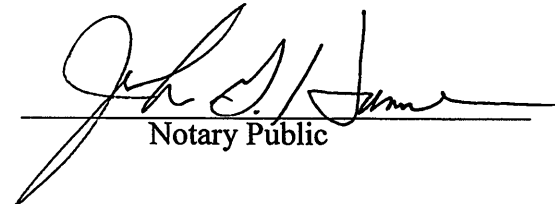
Case No. PU-16-666

AFFIDAVIT OF  
Sara Cardwell

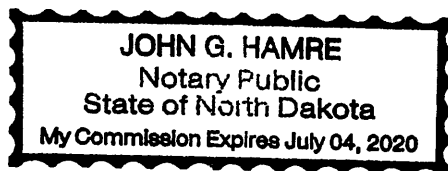
I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

  
Sara Cardwell

Subscribed and sworn to before me  
this 24th day of February, 2017.

  
Notary Public

SEAL



BEFORE THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Montana-Dakota Utilities Co.,  
a Division of MDU Resources Group, Inc.  
2016 Electric Rate Increase Application

Case No. PU-16-666

DIRECT TESTIMONY  
OF  
JACOB M. THOMAS, P.E.

ON BEHALF OF THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION  
ADVOCACY STAFF

February 24, 2017

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<b>LOAD RESEARCH.....</b>	<b>12</b>
Q. What did you review with respect to MDU's load research? .....	12
Q. Do you have any recommended adjustments to the load research study?.....	13
Q. How does MDU select its load research samples? .....	13
Q. What changes do you recommend for sample design and selection?.....	14
Q. What changes do you recommend for the data expansion? .....	14
Q. Do you recommend these adjustments to the load research be incorporated into MDU's cost of service and rate design for Case PU- 16-666?.....	16

<b>RATE DESIGN.....</b>	<b>16</b>
<b>Q. Please summarize the issues you will discuss with respect to rate design.....</b>	<b>16</b>
<b>Q. What do you recommend regarding rate design for Residential Service Rate 10?.....</b>	<b>17</b>
<b>Q. How does moving from a declining block rate to a flat rate in the winter impact residential consumers? .....</b>	<b>17</b>
<b>Q. How did you compute the flat energy charge you used in Exhibit PSC-11, Page 2?.....</b>	<b>18</b>
<b>Q. What recommendations do you have for Residential Electric Thermal Storage Service Rate 13? .....</b>	<b>19</b>
<b>Q. What recommendations do you have for Small General Service Rate 20? .....</b>	<b>19</b>
<b>Q. Have you prepared rate comparisons that demonstrate the comparative impacts of this change on Rate 20? .....</b>	<b>19</b>
<b>CONCLUSION.....</b>	<b>20</b>
<b>Q. Can you summarize the recommendations you make in your testimony? .....</b>	<b>20</b>
<b>Q. Does this conclude your testimony?.....</b>	<b>20</b>

1 **Q. Please state your name and place of employment.**

2 A. My name is Jacob M. Thomas. I am employed by GDS Associates, Inc.  
3 (“GDS”), and my office is located at 1850 Parkway Place, Suite 800,  
4 Marietta, Georgia 30067.

5 **Q. What position do you hold?**

6 A. I hold the position of Senior Project Manager.

7 **Q. On whose behalf are you submitting this testimony?**

8 A. I am submitting this testimony on behalf of North Dakota Public Service  
9 Commission Advocacy Staff (“Staff”).

10 **Q. What is your educational background?**

11 A. I graduated from the Georgia Institute of Technology with a Bachelor of  
12 Science in Industrial Engineering in 2000. I received a Master’s in  
13 Business Administration with a concentration in Finance from Auburn  
14 University in 2006.

15 **Q. Please describe your work experience.**

16 A. I began working with GDS in June 1996 as a cooperative student while  
17 attending the Georgia Institute of Technology. After graduation in  
18 December 2000, I accepted a full-time position in GDS’ Distribution  
19 Services department and have risen to my current position of Senior  
20 Project Manager in that department. In the past 20 years, I have provided  
21 statistical, financial, and economic consulting to utilities and regulatory  
22 agencies nationwide.

1           In the area of statistics, I have provided services to clients with  
2           respect to load forecasting, market research, sample design, load  
3           research, measurement and verification, and other statistical modeling. I  
4           have produced dozens of load forecasts, managed multiple customer  
5           survey processes, and performed impact evaluations of demand response  
6           and energy efficiency programs for several clients. I have also evaluated  
7           short-term and long-term price elasticity of demand for forecasting  
8           purposes.

9           In the areas of finance and economics, I specialize in retail and  
10          wholesale cost of service development and design, retail and wholesale  
11          rate design, financial forecasting, economic impact analysis, and benefit-  
12          cost analysis of demand response programs. In the past three years, I  
13          have managed or had significant input into cost of service, rate design,  
14          and financial forecasting projects for twenty different clients. I have  
15          performed benefit-cost analyses for an additional eight clients in that time.

16          My resume is provided as exhibit PSC-8.

17      **Q. Do you have any professional registrations and memberships?**

18      A. Yes, I am a registered Professional Engineer in Georgia. I am a member  
19          of the Institute of Industrial Engineers and the American Statistical  
20          Association.

1 **Q. Have you testified in North Dakota in the past?**

2 A. I have not.

3 **Q. Have you testified in any other regulatory proceedings?**

4 A. I have testified as an expert witness in several other states and been a co-  
5 author of joint reports filed in cases as well. I testified as an expert before  
6 the Vermont Public Service board, providing testimony regarding the  
7 economic impacts of continued operations of the Vermont Yankee nuclear  
8 power plant. I testified in the area of weather normalization of gas sales  
9 before the Michigan Public Service Commission. I also testified before the  
10 North Carolina Utilities Commission, providing testimony supporting cost  
11 of service computations for an intervenor. I have also been a co-author of  
12 reports in connection to cases before the Delaware Public Service  
13 Commission, the Kentucky Public Service Commission, and the Utah  
14 Public Service Commission. In those joint reports, prepared in  
15 coordination with other GDS experts, I was tasked with focusing on  
16 demand response, load research, and load forecasting issues.

17

## 18 **TESTIMONY PURPOSE AND SUMMARY**

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

20 A. My testimony introduces revised cost of service results and revenue  
21 allocations to rate classes reflecting the revenue requirement

1 recommended by Staff witness Richard A. Polich. Furthermore, I discuss  
2 the load research study used by Montana-Dakota Utilities, Co. (“MDU”) to  
3 estimate class contributions to demands used to allocated demand-related  
4 costs in the cost of service study. Finally, I recommend changes to  
5 several components of MDU’s proposed rate designs.

6 **Q. How is your testimony organized?**

7 A. I have organized my testimony into the following sections:

- 8 1. **Cost of Service** – Calculation of Cost of Service results that reflect all  
9 adjustments to the revenue requirement recommended by Staff witness  
10 Richard A. Polich.
- 11 2. **Recommended Revenue Allocation to Classes** – Allocation of the  
12 revenue requirement to classes reflecting Staff witness Richard A.  
13 Polich’s recommended revenue requirement.
- 14 3. **Load Research** – Review of and recommendations related to load  
15 research supporting estimates for class demand allocators.
- 16 4. **Rate Design** – Recommendations related to rate design irrespective of  
17 class revenue requirements.
- 18 5. **Conclusions** – Summary of testimony and recommendations.

19  
20 **Q. Have you prepared any Exhibits?**

21 A. Yes, the following is a list of Exhibits included with my testimony:

22

1	<u>EXHIBIT</u>	<u>DESCRIPTION</u>
2	PSC-8	Jacob M. Thomas Resume
3	PSC-9	Adjusted Cost of Service Results
4	PSC-10	Adjusted Revenue Allocation to Customer Classes
5	PSC-11	General Winter Bill Rate Comparisons

6

7 **COST OF SERVICE**

8 **Q. What have you prepared with respect to cost of service?**

9 A. I have prepared a cost of service study that reflects all recommended  
10 adjustments to the revenue requirement, including changes to  
11 investments, and expenses made by Staff witness Richard A. Polich. The  
12 resultant study outputs are shown in Exhibit PSC-9.

13 **Q. Please summarize how you prepared the Staff adjusted cost of  
14 service study.**

15 A. I used MDU's electronic spreadsheet version of their cost of service  
16 model provided in response to Staff Data Request 1 question 2. First,  
17 I computed an updated version of the Cost of Service to reflect new  
18 projected income statements and rate base for 2017. Then, I created  
19 a second version of that model and adjusted certain inputs to reflect  
20 the changes recommended by Mr. Polich.

1 **Q. Please describe how you prepared the Cost of Service that reflects**  
2 **new projected information.**

3 A. I used revised projected income and rate base information provided  
4 by MDU in their response to Staff Data Request Set 1, Question 1 to  
5 obtain updated 2017 projections<sup>1</sup>. I then input that data into the Cost  
6 of Service model provided by MDU in response to Staff Data Request  
7 Set 1, Question 2<sup>2</sup>. I then checked to ensure that the resultant North  
8 Dakota income statement and Rate of Return from my Cost of Service  
9 model matched that in the data supplied by MDU in response to Staff  
10 Data Request Set 1 Question 1.

11 **Q. Please describe how you prepared the Cost of Service that reflects**  
12 **Mr. Polich's recommended adjustments.**

13 A. I started with the Cost of Service model that reflects the updated 2017  
14 projections, described above. Then, I adjusted certain inputs in the  
15 Cost of Service model to reflect those adjustments recommended by  
16 Staff witness Mr. Polich. The following list describes each of the  
17 adjustments I made to produce the adjusted study.

---

<sup>1</sup> Two Excel files as provided by MDU were used to update all inputs into the Cost of Service model: "ND Elec Rate Base 16 – Excl Wind.xlsx" and "ND Electric Income Statement (2016).xlsx".

<sup>2</sup> The Cost of Service Model was provided in Excel format and is called "Response No. 1.2 Statement M.xlsx"

- 1           • Production plant in service and accumulated depreciation
- 2           rate base adjustments and an adjustment to production
- 3           plant depreciation expense to reflect Mr. Polich's
- 4           recommendations with respect to the Lewis & Clark RICE
- 5           units.
- 6           • Working capital adjustments in rate base to reflect Mr.
- 7           Polich's recommendations with respect to the loss on the
- 8           sale of housing and plant decommissioning.
- 9           • Adjustment to operating expenses to reflect recommended
- 10          adjustment to bonus and incentive compensation expenses.
- 11          • Adjustments to accumulated deferred income tax in working
- 12          capital and income tax expenses to reflect the tax
- 13          implications of the all adjustments recommended by Mr.
- 14          Polich.

15   **Q. Please summarize the resultant adjusted cost of service results.**

16   A. Table JMT 1 provides the North Dakota system and class rates of  
17   return for the MDU cost of service as filed and for the Cost of Service  
18   model that reflects the updated 2017 projections. Furthermore, I  
19   show the relative rate of return, which is the class rate of return  
20   divided by the North Dakota system rate of return.

21           Table JMT 2 provides the rates of return and relative rates of  
22   return for the Cost of Service that reflects the updated 2017

1 projections and the model adjusted to reflect Staff's recommended  
 2 adjustments.

3 **TABLE JMT-1**  
**Comparison of North Dakota Class Cost of Service Rates of Return**  
**As Filed COS versus COS Adjusted to Reflect Updated 2017 Projections**

Line No.	Class	As Filed MDU ROR <sup>1</sup>	As Filed Relative ROR <sup>2</sup>	Updated 2017 ROR	Updated 2017 Relative ROR <sup>3</sup>
(a)	(b)	(c)	(d)	(e)	(f)
1	Residential Rate 10	3.818%	0.654	4.027%	0.665
2	Small General Rate 20	5.395%	0.924	5.638%	0.931
3	Irrigation Rate 25	-1.195%	(0.205)	-1.012%	(0.167)
4	Large General Primary Rate 30	7.580%	1.298	7.781%	1.284
5	Large General Secondary Rate 30	8.416%	1.441	8.636%	1.426
6	TOD Large General Rate 31 Primary	4.198%	0.719	4.010%	0.662
7	TOD Large General Rate 31 Secondary	5.844%	1.001	6.060%	1.000
8	Space Heating Rate 32	6.077%	1.041	6.233%	1.029
9	Small Municipal Rate 40	2.701%	0.463	3.135%	0.517
10	Municipal Lighting Rate Primary 41	13.080%	2.240	13.420%	2.215
11	Municipal Lighting Rate Secondary 41	10.847%	1.858	11.516%	1.901
12	Municipal Pumping Primary Rate 48	2.020%	0.346	2.261%	0.373
13	Municipal Pumping Secondary Rate 48	4.070%	0.697	4.349%	0.718
14	Outdoor Lighting Rate 52	11.879%	2.034	12.011%	1.983
15	Interruptible Demand Response Rate 38	6.616%	1.133	6.844%	1.130
16	<b>Total North Dakota</b>	<b>5.839%</b>	<b>1.000</b>	<b>6.058%</b>	<b>1.000</b>

12 1 - From Statement M, Pages 1-15.

13 2 - Column C in each row divided by column C, line 16, Total North Dakota, 5.839%.

14 3 - Column E in each row divided by column E, line 16, Total North Dakota, 6.058%.

15 **TABLE JMT-2**  
**Comparison of North Dakota Class Cost of Service Rates of Return**  
**COS Adjusted to Reflect Updated 2017 Projections versus COS Adjusted to Reflect Staff Recommendations**

Line No.	Class	Updated 2017 ROR	Updated 2017 Relative ROR <sup>1</sup>	Staff Adjusted ROR	Staff Adjusted Relative ROR <sup>2</sup>
(a)	(b)	(c)	(d)	(e)	(f)
1	Residential Rate 10	4.027%	0.665	4.643%	0.690
2	Small General Rate 20	5.638%	0.931	6.273%	0.933
3	Irrigation Rate 25	-1.012%	(0.167)	-0.407%	(0.061)
4	Large General Primary Rate 30	7.781%	1.284	8.525%	1.267
5	Large General Secondary Rate 30	8.636%	1.426	9.396%	1.397
6	TOD Large General Rate 31 Primary	4.010%	0.662	4.910%	0.730
7	TOD Large General Rate 31 Secondary	6.060%	1.000	6.729%	1.000
8	Space Heating Rate 32	6.233%	1.029	6.940%	1.032
9	Small Municipal Rate 40	3.135%	0.517	3.588%	0.533
10	Municipal Lighting Rate Primary 41	13.420%	2.215	14.978%	2.227
11	Municipal Lighting Rate Secondary 41	11.516%	1.901	11.918%	1.772
12	Municipal Pumping Primary Rate 48	2.261%	0.373	2.797%	0.416
13	Municipal Pumping Secondary Rate 48	4.349%	0.718	4.937%	0.734
14	Outdoor Lighting Rate 52	12.011%	1.983	13.004%	1.933
15	Interruptible Demand Response Rate 38	6.844%	1.130	7.486%	1.113
16	<b>Total North Dakota</b>	<b>6.058%</b>	<b>1.000</b>	<b>6.727%</b>	<b>1.000</b>

16 1 - Column C in each row divided by column C, line 16, Total North Dakota, 6.058%.

17 2 - Column E in each row divided by column E, line 16, Total North Dakota, 6.727%.

1           Although the class-by-class rates of return are similar in all  
2           three versions of the Cost of Service, the Staff recommended  
3           adjustments do narrow the range of outcomes. By observing the  
4           relative ROR statistic, one can see that the range of class returns as a  
5           ratio of the overall North Dakota system return narrows under the  
6           Staff recommended version. Relative rates of return range from  
7           -0.205 to 2.240 under the MDU filed Cost of Service. Under the Staff  
8           adjusted Cost of Service, relative rates of return range from -0.061 to  
9           2.227.

10

11    **REVENUE ALLOCATION TO CLASSES**

12    **Q.    Please describe your recommended revenue allocation.**

13    A.    I started with the overall revenue requirement as recommended by Staff  
14           witness Richard A. Polich. Mr. Polich recommends a base rate revenue  
15           increase of \$513,316. Then, I evaluated the rates of return by class from  
16           the Staff adjusted cost of service, as shown in Table JMT 2 above.  
17           Finally, I prepared an allocation of the Staff recommended rate increase to  
18           the classes as shown in Table JMT 3 below:

**TABLE JMT-3**  
**Staff Recommended Base Rate Revenue Increases by Customer Class**

Customer Class	Recommended Rate Increase*	
	Amount (\$000)	%
Residential Service	\$316	0.43%
Small General Service	\$45	0.35%
Large General Service	\$136	0.15%
Lighting	\$3	0.15%
Municipal Pumping	\$15	0.55%
Total North Dakota Electric	\$515	0.28%

\*Exclusive of Renewable Rider and Transmission Cost Adjustment Rider.

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**Q. Please describe how you allocated Mr. Polich’s recommended revenue increase to the various customer classes.**

A. MDU witness Tamie Aberle describes the method by which the Company allocated their requested revenue increase to the classes. On page 6 of her direct testimony in lines 8-14, she describes a two-step process used to determine the maximum and minimum increases to be placed on any one class because “It was determined that mitigation was necessary in order to balance the fair return standard with the recognition of customer impacts.” I employed a similar two-step process to Ms. Aberle, although I modified it to reflect the lower overall percent increase recommended by Staff witness Polich. I set a maximum percent increase of 2.0 times the

1 overall North Dakota recommended increase and a minimum of 0.5 times  
2 the overall increase. The resultant maximum increase is 0.56% and  
3 minimum increase is 0.14%. Exhibit PSC-10, page 1 shows the revenue  
4 allocation I recommend.

5 Next, I looked at the class rates of return prior to the revenue  
6 increase, and assigned minimum and near minimum increases to the two  
7 classes earning higher than system rates of return. Total Lighting and  
8 Total General Service received a 0.15% increase.

9 Total Municipal Pumping, which currently has a rate of return below  
10 the North Dakota system was then assigned the highest rate increase of  
11 0.55%. Next, the Total General Service increase was set at 0.35% to  
12 recognize it has a lower than system return but higher return than  
13 Residential and Municipal Pumping. The Residential increase was then  
14 computed to recover the remaining revenue increase, which results in an  
15 increase of 0.43%.

16 My recommended revenue allocation provides for reasonable  
17 increases on all classes and moves all classes closer to equitable rates of  
18 return, as shown in Table JMT 4.

19  
20  
21  
22

**TABLE JMT-4**  
**Resultant Rates of Return After Staff Recommended Revenue Increases**

Customer Class	Prior to Rate Increase		After Rate Increase	
	Rate of Return	Relative ROR	Rate of Return	Relative ROR
Residential Service	4.643%	0.690	4.724%	0.696
Small General Service	6.103%	0.907	6.174%	0.909
Large General Service	9.050%	1.345	9.088%	1.339
Lighting	12.314%	1.831	12.344%	1.818
Municipal Pumping	4.252%	0.632	4.357%	0.642
1 Total North Dakota Electric	6.727%	1.000	6.789%	1.000

2

3 **LOAD RESEARCH**

4 **Q. What did you review with respect to MDU's load research?**

5 A. In response to Staff data request Set 2, Question 30, MDU provided  
6 several spreadsheets and responses describing the load research used in  
7 their cost of service study allocator development. I reviewed this  
8 information to ascertain if industry standard techniques were used by  
9 MDU. The load research information is used to compute the 12-CP  
10 demands for each class and is therefore an important aspect of MDU's  
11 cost of service model.

1 **Q. Do you have any recommended adjustments to the load research**  
2 **study?**

3 A. Yes, I do. I recommend MDU use a different methodology for sample  
4 selection. I also recommend MDU use a different methodology to  
5 perform the data expansion to expand sample demands to class  
6 demands. I will discuss each in more detail below.

7 **Q. How does MDU select its load research samples?**

8 A. According to MDU's response to Staff data request Set 2, Question  
9 30.c: "Montana-Dakota prepared random samples for rate classes  
10 having sufficient numbers of customers to make a census impractical  
11 and for which interval data were available." In load research, when  
12 interval data is used for every customer in a class, it is called a  
13 census. The sample size was designed to achieve a 90% confidence  
14 level with a 10% error tolerance. For the sampled classes, the  
15 Company randomly selected accounts that had 12 months of 2015  
16 billing data. Data for all customers on Rate class 130 were included  
17 so this class was not sampled. Very small sample sizes were used in  
18 some cases including class 250 (2 out of 40 accounts), class 300 (2  
19 out of 36 accounts), class 323 (2 out of 536 accounts), and class 400  
20 (8 out of 39 accounts).

21

1 **Q. What changes do you recommend for sample design and selection?**

2 A. I recommend that MDU generally employ a stratified random sampling  
3 scheme for its load research program. With a stratified random  
4 sample, the class is divided into strata and a random sample of  
5 customers from each stratum are drawn. If the individual strata of  
6 customers are more homogenous than the overall population, then  
7 stratification can increase the precision of sample estimates and/or  
8 reduce the overall sample size required. For those classes that have  
9 demand charges and demands are recorded in MDU's billing system,  
10 then the demand can be a natural stratification variable. For other  
11 classes, stratifying based on energy is often employed in the industry.  
12 For classes with very few customers (less than 50) or classes with  
13 highly homogenous load characteristics, a simple random sample is  
14 likely to be equally representative and provide similar precision to a  
15 stratified approach. For classes with fewer than 50 accounts, using  
16 interval data for all customers is preferable to either a stratified or  
17 simple random sample.

18 **Q. What changes do you recommend for the data expansion?**

19 A. Data expansion is the process by which a load researcher uses the  
20 sample data to expand it to represent the entire rate class. Based on  
21 MDU's response to Staff data request 2, question 30, I conclude that  
22 MDU uses a mean-per unit ("MPU") expansion approach. In an MPU

1 expansion, the load research data is used to calculate a variable of  
2 interest (for instance, a CP demand for a given month) on a per-  
3 customer basis. That variable per customer ratio is then multiplied by  
4 the total number of customers in the class to estimate the variable of  
5 interest for the entire class.

6 I recommend MDU change to a ratio expansion technique. In  
7 ratio expansion, correlation of the variable of interest with another  
8 variable that is available for the sample customers and the population  
9 is used to obtain increased precision in the expanded estimate. As  
10 described in the *Load Research Manual*, produced by the Association  
11 of Edison Illuminating Companies:

12 "Ratio estimation is a technique that can take advantage of the  
13 correlation of the variable of interest  $y$  with another variable  $x$  to obtain  
14 increased precision. Class demand estimates for rate classes and  
15 other populations with 'known' total energy use  $X$  are adjusted by the  
16 ratio of demand  $y$  to energy use  $x$  for the sample. When  $x$  and  $y$  are  
17 sufficiently correlated, the relative variance of the estimated ratio is  
18 less than the relative variance of either  $x$  or  $y$  alone. That is,  
19 knowledge of  $x$  provides information about  $y$ . As a result, the ratio  
20 estimator has better precision than the mean-per-unit estimator, which  
21 ignores the information about  $x$ ."<sup>3</sup>

22  
23 This paragraph concludes that, if there is positive correlation  
24 between class energy and class demand, then the ratio estimation  
25 technique will improve precision. Given the high likelihood that such a

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<sup>3</sup> Association of Edison Illuminating Companies. *Load Research Manual*. 2<sup>nd</sup> ed. 2001. Page 7-8.

1 positive correlation exists for MDU's rate classes, I recommend use of  
2 the ratio estimation technique to improve the precision of demand  
3 estimates.

4 **Q. Do you recommend these adjustments to the load research be**  
5 **incorporated into MDU's cost of service and rate design for Case PU-**  
6 **16-666?**

7 A. I do not recommend that these changes be made in this case.  
8 Changing the sample requires starting the load research process from  
9 step 1 and could not be accomplished in a timely manner for the  
10 purposes of this case. Rather, I recommend MDU make these  
11 changes to its load research program for future rate case and other  
12 load research needs.

13  
14 **RATE DESIGN**

15 **Q. Please summarize the issues you will discuss with respect to rate**  
16 **design.**

17 A. I make recommendations with respect to the rate design for three rates:  
18 Residential Service Rate 10, Optional Residential ETS Rate 13, and SGS  
19 Rate 20. I also discuss the concept of a residential demand rate as a  
20 future concept for MDU to consider.

1 **Q. What do you recommend regarding rate design for Residential**  
2 **Service Rate 10?**

3 A. I recommend MDU eliminate the declining block rate for the energy charge  
4 in winter months. A declining block rate design is typically one that  
5 incorporates customer-related fixed costs into the first energy block when  
6 the basic service charge does not recover full customer-related costs.  
7 With MDU's proposed basic service charge of \$0.65 per day, the full  
8 customer-related cost is being recovered through the basic service  
9 charge, eliminating the need to recover additional customer costs in the  
10 first 750 kWh per month in winter months.

11 Furthermore, the long-run marginal cost of energy produced is  
12 increasing and not decreasing, as utilities rely on newer and more  
13 emission-efficient units to produce marginal energy in the future. A  
14 declining block rate does not reflect the fact that marginal costs will  
15 increase over the long-run.

16 **Q. How does moving from a declining block rate to a flat rate in the**  
17 **winter impact residential consumers?**

18 A. Changing the rate structure in winter months to a flat energy charge will  
19 help ease the impacts on low usage customers associated with the  
20 increasing Basic Service Charge. In Exhibit PSC-11, I provide general  
21 winter bill rate comparisons that demonstrate that fact. On page 1, I show  
22 a comparison of the present Rate 10 for winter months versus MDU's

1 proposed rate with the declining block rate. On page 2, I show a  
2 comparison of the present Rate 10 for winter months versus a flat rate  
3 energy charge designed to recover the same revenue for those kWh as  
4 MDU's proposed design. When comparing the bills at lower usage levels,  
5 it is clear that the flat energy charge helps lower usage customers absorb  
6 the impact of increasing the Basic Service Charge. For instance, looking  
7 at line 7 on pages 1 and 2 of Exhibit PSC-11, a customer that uses 500  
8 kWh in a given winter month will see an increase of \$8.14, or 13.7%, on  
9 that bill under MDU's proposed rates with a declining energy block. Under  
10 the flat energy charge, that customer would see a \$2.31, or 3.9%,  
11 increase on that bill.

12 **Q. How did you compute the flat energy charge you used in Exhibit**  
13 **PSC-11, Page 2?**

14 **A.** I used the rate design statements provided by MDU to compute a flat  
15 energy charge in winter months of \$0.04900 per kWh. In Statement N,  
16 page 7, MDU shows that the winter energy charges are designed to  
17 recover \$25,688,615 in revenue over 524,290,825 kWh. That results in an  
18 average rate of \$0.04900 per kWh, which is what I used for the rate  
19 comparison in Exhibit PSC-11 page 2.

1 **Q. What recommendations do you have for Residential Electric Thermal**  
2 **Storage Service Rate 13?**

3 A. To be consistent with the design of the Residential Service Rate 10, I  
4 recommend MDU eliminate the declining block energy charge in the winter  
5 on-peak energy component of the rate. The same reasoning with respect  
6 to recovery of customer-related fixed costs and reflecting that marginal  
7 costs will increase over the long-run apply to the Residential Electric  
8 Thermal Storage customers during their on-peak period.

9 **Q. What recommendations do you have for Small General Service Rate**  
10 **20?**

11 A. To be consistent with the design of the Residential Service Rate 10, I  
12 recommend MDU eliminate the declining block energy charge in the winter  
13 on-peak energy component of the rate. The same reasoning with respect  
14 to recovery of customer-related fixed costs and reflecting that marginal  
15 costs will increase over the long-run apply to the Small General Service  
16 class of customers.

17 **Q. Have you prepared rate comparisons that demonstrate the**  
18 **comparative impacts of this change on Rate 20?**

19 A. I have, they are shown in Exhibit PSC-11 pages 3 and 4. The flat energy  
20 charge was computed in a manner consistent with the approach I  
21 described for Rate 10, using Schedule N page 10.

22

1 **CONCLUSION**

2 **Q. Can you summarize the recommendations you make in your**  
3 **testimony?**

4 A. Yes. First, I have prepared and presented adjusted cost of service results  
5 that reflect the adjustments recommended by Staff witness Richard A.  
6 Polich. Second, I have developed a recommended schedule of revenue  
7 increase allocations to the rate classes that reflect the total North Dakota  
8 system revenue requirements recommended by Mr. Polich.

9 I also reviewed MDU's load research information provided in this  
10 case and have made two recommendations for future load research  
11 studies. I recommend using a stratified random sampling technique for  
12 selecting samples in the next load research study. I also recommend  
13 using a ratio estimation technique to expand the sample data into class  
14 demand estimates.

15 Finally, I have recommended elimination of the declining block  
16 energy charge structure for Rate 10, Rate 13, and Rate 20 winter months.  
17 I prepared rate comparisons that demonstrate eliminating the declining  
18 block structure helps lower usage customers absorb the bill increases  
19 associated with increasing the Basic Service Charges on those rates.

20 **Q. Does this conclude your testimony?**

21 A. Yes, it does.

STATE OF NORTH DAKOTA

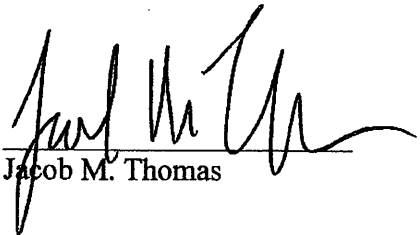
BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of  
MONTANA-DAKOTA UTILITIES CO.,  
A Division of MDU Resources Group, Inc.  
for authority to Increase Rates for Electric Service in North Dakota

Case No. PU-16-666

AFFIDAVIT OF  
Jacob M. Thomas

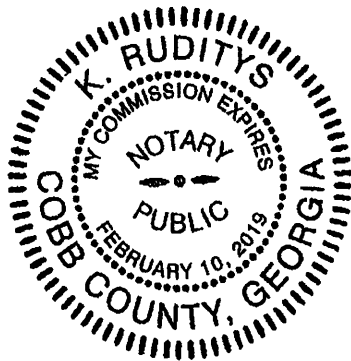
I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

  
Jacob M. Thomas

Subscribed and sworn to before me  
this 24th day of February, 2017.

  
Notary Public

SEAL





JACOB M. THOMAS, P.E.  
Senior Project Manager

## EDUCATION

Master of Business Administration, Finance, Auburn University, 2006

Bachelor of Science in Industrial Engineering, Cooperative Program, With Highest Honors, Georgia Institute of Technology, 2000

## PROFESSIONAL REGISTRATION

Registered Professional Engineer in the State of Georgia

## PROFESSIONAL MEMBERSHIPS

National Society of Professional Engineers (NSPE)  
American Statistical Association (ASA)  
Institute of Industrial Engineers (IIE)

## PROFESSIONAL EXPERIENCE

**GDS Associates, Inc.**, June 1996 to Present

Employed as cooperative student and began full time employment in 2000. During his career at GDS, Mr. Thomas has developed expertise and experience in many areas of utility practice including load & financial forecasting, residential consumer surveys, load research, cost of service studies, retail and wholesale rate design, economic impact analysis, benefit-cost analyses, load management evaluation, statistical impact analysis, and market research.

## PROJECT EXPERIENCE

### **General Experience Includes:**

- Designed cost of service models and performed retail rate analysis for municipals and cooperatives in Alabama, Alaska, Arkansas, Florida, Georgia, Indiana, Massachusetts, Ohio, Pennsylvania, South Carolina, Texas, and Virginia. Specific work has included development of cost allocation factors in various areas of operation, calculation of impacts of rate changes to customers, determination of the company's financial competitive position, classification of plant investment and operating expenses, development of pro forma financial statements, and alternative rate design calculations.
- Designed a cost of service model template for use by Hoosier Energy. Developed a functional

spreadsheet-based model and performed a training seminar with Hoosier staff.

- Prepared financial forecasts for electric cooperatives in South Carolina, Virginia, Tennessee and Georgia, and for municipals in Arkansas and Pennsylvania. Work included regression analysis, review of current long-term debt situation, customer and demand forecasts, plant forecasts, and sensitivity analysis.
- Completed an economic impact analysis of instituting a Renewable Portfolio Standard in the state of North Carolina. Direct, indirect, and induced job impacts were measured for construction, operations and maintenance, and pertinent fuel supplies for various conventional and renewable resources, as well as effects of electricity price increases on residential and commercial consumers.
- Economic impact analysis of continued operation of nuclear power plant in Vermont. Analysis included impacts to Vermont economy in general, Vermont government, and in-state utility ratepayers. Prepared testimony as an expert witness on economic analysis on behalf of the Department of Public Service.
- Expert witness in a natural gas retail rate study in Michigan. Subject of testimony was weather normalization methodologies in forecasting.
- Developed state-wide energy supply and consumption projections by major customer classification and type of fuel for Vermont Department of Public Service and Virginia Department of Mines, Minerals, and Energy. Utilized Energy Information Administration data and econometric and trending techniques to complete projections.
- Assisted in development of wholesale rates for G&Ts in Indiana, Minnesota and Wisconsin. Work involved projections of cost pools and billing units, development of pro forma rates and impacts on member systems, evaluation of rate alternatives and riders, and considering the implications of an aggressive load management program.
- Instructor at Institute of Public Utilities Forecasting Workshop held in 2012. Taught on the subject of Statistically Adjusted End-Use models.

## REGULATORY EXPERIENCE

- Delaware Public Service Commission (Co-Author of Joint Report – Evaluation of Delmarva Power & Light Integrated Resource Plan)
- Kentucky Public Service Commission (Panel Representative in Big Rivers Electric Corporation Integrated Resource Plan)
- Michigan Public Service Commission (Expert Witness – Weather Normalization)
- North Carolina Utilities Commission (Expert Witness – Cost of Service Modeling)
- Utah Public Service Commission (Co-Author of Joint Report – Evaluation of PacifiCorp Load Forecast)
- Vermont Public Service Board (Expert Witness – Economic Impact Analysis of Vermont Yankee)

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	Total North Dakota	Residential Rate 10			Total Residential Rate 10	
		Demand Prod. & Trans.	Demand Distribution	Energy		Customer
Rate Base	520,229	145,788	34,043	1,328	62,055	243,214
Operating Income for Proposed Return	38,805	10,877	2,539	99	4,629	18,144
Current Operating Income	34,998	(12,705)	(2,218)	26,388	(173)	11,292
Increase in Operating Income	3,807	23,582	4,757	(26,289)	4,802	6,852
Related Taxes for Increase						
State & Federal Income Taxes	2,311	14,328	2,891	(15,977)	2,918	4,160
Total Increase in Revenue	6,118	37,910	7,648	(42,266)	7,720	11,012
Total Revenue Before Increase	186,308	1,471	427	62,441	11,201	75,540
Total Cost of Service Required from Rates	192,426	39,381	8,075	20,175	18,921	86,552
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	1,471	427	1,213	980	4,091
Revenue Required from Rates	182,917	37,910	7,648	18,962	17,941	82,461
Projected Rate of Return Before Increase	6.727%					4.643%
Projected Billing Units						
Kwh	2,014,529,000	770,939,000	770,939,000	770,939,000		
Kw Demand	3,304,802					
Bills	1,170,228				960,036	
Unit Cost of Service						
\$ per Kwh		0.049	0.010	0.025		
\$ per Kw Demand						
\$ per Customer Per Month					18.69	
Operating Income/Inverse of Federal income tax rate:						62.1985%
Operating Income for Proposed Return:						7.459%

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	Total North Dakota	Small General Rate 20			Total Small General Rate 20	
		Demand Prod. & Trans.	Demand Distribution	Energy		Customer
Rate Base	520,229	21,245	4,424	194	12,015	37,878
Operating Income for Proposed Return	38,805	1,585	330	14	896	2,825
Current Operating Income	34,998	(1,854)	(287)	3,878	639	2,376
Increase in Operating Income	3,807	3,439	617	(3,864)	257	449
Related Taxes for Increase						
State & Federal Income Taxes	2,311	2,090	375	(2,348)	156	273
Total Increase in Revenue	6,118	5,529	992	(6,212)	413	722
Total Revenue Before Increase	186,308	212	55	9,157	3,126	12,550
Total Cost of Service Required from Rates	192,426	5,741	1,047	2,945	3,539	13,272
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	212	55	147	176	590
Revenue Required from Rates	182,917	5,529	992	2,798	3,363	12,682
Projected Rate of Return Before Increase	6.727%					6.273%
Projected Billing Units						
Kwh	2,014,529,000	112,526,000	112,526,000	112,526,000		
Kw Demand	3,304,802					
Bills	1,170,228				138,144	
Unit Cost of Service						
\$ per Kwh		0.049	0.009	0.025		
\$ per Kw Demand						
\$ per Customer Per Month					24.34	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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	Total North Dakota	Irrigation Rate 25			Total Irrigation Rate 25	
		Demand Prod. & Trans.	Demand Distribution	Energy		Customer
Rate Base	520,229	92	241	2	156	491
Operating Income for Proposed Return	38,805	7	18	0	12	37
Current Operating Income	34,998	(7)	(6)	17	(6)	(2)
Increase in Operating Income	3,807	14	24	(17)	18	39
Related Taxes for Increase						
State & Federal Income Taxes	2,311	9	15	(10)	11	25
Total Increase in Revenue	6,118	23	39	(27)	29	64
Total Revenue Before Increase	186,308	1	19	59	12	91
Total Cost of Service Required from Rates	192,426	24	58	32	41	155
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	1	3	2	1	7
Revenue Required from Rates	182,917	23	55	30	40	148
Projected Rate of Return Before Increase	6.727%					(0.407%)
Projected Billing Units						
Kwh	2,014,529,000			1,267,000		
Kw Demand	3,304,802	8,085	8,085			
Bills	1,170,228				552	
Unit Cost of Service						
\$ per Kwh				0.024		
\$ per Kw Demand		2.84	6.80			
\$ per Customer Per Month					72.46	
Operating Income/Inverse of Federal income tax rate:						
Operating Income for Proposed Return:						

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	Total North Dakota	Large General Primary Rate 30			Total LG Primary Rate 30	
		Demand Prod. & Trans.	Demand Distribution	Energy		Customer
Rate Base	520,229	27,557	6,571	334	236	34,698
Operating Income for Proposed Return	38,805	2,055	490	25	18	2,588
Current Operating Income	34,998	(2,404)	2,116	3,229	17	2,958
Increase in Operating Income	3,807	4,459	(1,626)	(3,204)	1	(370)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	2,710	(988)	(1,947)	1	(224)
Total Increase in Revenue	6,118	7,169	(2,614)	(5,151)	2	(594)
Total Revenue Before Increase	186,308	275	4,188	10,185	53	14,701
Total Cost of Service Required from Rates	192,426	7,444	1,574	5,034	55	14,107
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	275	83	254	4	616
Revenue Required from Rates	182,917	7,169	1,491	4,780	51	13,491
Projected Rate of Return Before Increase	6.727%					8.525%
Projected Billing Units						
Kwh	2,014,529,000			195,765,000		
Kw Demand	3,304,802	468,864	468,864			
Bills	1,170,228				516	
Unit Cost of Service						
\$ per Kwh				0.024		
\$ per Kw Demand		15.29	3.18			
\$ per Customer Per Month					98.84	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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	Large General Secondary Rate 30					Total LG Secondary Rate 30
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	
Rate Base	520,229	128,549	27,046	1,302	11,032	167,929
Operating Income for Proposed Return	38,805	9,588	2,017	97	823	12,525
Current Operating Income	34,998	(11,214)	13,350	13,110	533	15,779
Increase in Operating Income	3,807	20,802	(11,333)	(13,013)	290	(3,254)
Related Taxes for Increase						
Slate & Federal Income Taxes	2,311	12,643	(6,888)	(7,909)	176	(1,978)
Total Increase in Revenue	6,118	33,445	(18,221)	(20,922)	466	(5,232)
Total Revenue Before Increase	186,308	1,284	24,793	40,566	2,636	69,279
Total Cost of Service Required from Rates	192,426	34,729	6,572	19,644	3,102	64,047
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	1,284	336	990	159	2,769
Revenue Required from Rates	182,917	33,445	6,236	18,654	2,943	61,278
Projected Rate of Return Before Increase	6.727%					9.396%
Projected Billing Units						
Kwh	2,014,529,000			755,983,226		
Kw Demand	3,304,802	2,281,944	2,281,944			
Bills	1,170,228				55,044	
Unit Cost of Service						
\$ per Kwh				0.025		
\$ per Kw Demand		14.66	2.73			
\$ per Customer Per Month					53.47	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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	TOD Large General Rate 31 Primary					Total TOD LG Primary Rate 31
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	
Rate Base	520,229	292	85	4	6	387
Operating Income for Proposed Return	38,805	22	6	0	0	28
Current Operating Income	34,998	(25)	18	25	1	19
Increase in Operating Income	3,807	47	(12)	(25)	(1)	9
Related Taxes for Increase						
State & Federal Income Taxes	2,311	29	(7)	(15)	(1)	6
Total Increase in Revenue	6,118	76	(19)	(40)	(2)	15
Total Revenue Before Increase	186,308	3	40	92	1	136
Total Cost of Service Required from Rates	192,426	79	21	52	(1)	151
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	3	1	3	0	7
Revenue Required from Rates	182,917	76	20	49	(1)	144
Projected Rate of Return Before Increase	6.727%					4.910%
Projected Billing Units						
Kwh	2,014,529,000			2,081,000		
Kw Demand	3,304,802	3,954	3,954			
Bills	1,170,228				12	
Unit Cost of Service						
\$ per Kwh				0.024		
\$ per Kw Demand		19.22	5.06			
\$ per Customer Per Month					(83.33)	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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	TOD Large General Rate 31 Secondary					Total TOD LG Seconda Rate 31
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	
Rate Base	520,229	3,010	634	30	190	3,864
Operating Income for Proposed Return	38,805	225	47	2	14	288
Current Operating Income	34,998	(263)	313	206	4	260
Increase in Operating Income	3,807	488	(266)	(204)	10	28
Related Taxes for Increase						
State & Federal Income Taxes	2,311	297	(162)	(124)	6	17
Total Increase in Revenue	6,118	785	(428)	(328)	16	45
Total Revenue Before Increase	186,308	30	582	785	39	1,436
Total Cost of Service Required from Rates	192,426	815	154	457	55	1,481
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	30	7	23	1	61
Revenue Required from Rates	182,917	785	147	434	54	1,420
Projected Rate of Return Before Increase	6.727%					6.729%
Projected Billing Units						
Kwh	2,014,529,000			17,694,774		
Kw Demand	3,304,802	46,446	46,446			
Bills	1,170,228				816	
Unit Cost of Service						
\$ per Kwh				0.025		
\$ per Kw Demand		16.90	3.16			
\$ per Customer Per Month					66.18	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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	Total North Dakota	Space Heating Rate 32			Customer	Total Space Heating Rate 32
		Demand Prod. & Trans.	Demand Distribution	Energy		
Rate Base	520,229	6,858	2,836	96	282	10,072
Operating Income for Proposed Return	38,805	512	212	7	21	752
Current Operating Income	34,998	(597)	159	1,143	(6)	699
Increase in Operating Income	3,807	1,109	53	(1,136)	27	53
Related Taxes for Increase						
State & Federal Income Taxes	2,311	674	32	(690)	16	32
Total Increase in Revenue	6,118	1,783	85	(1,826)	43	85
Total Revenue Before Increase	186,308	69	591	3,282	118	4,060
Total Cost of Service Required from Rates	192,426	1,852	676	1,456	161	4,145
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	69	35	73	6	183
Revenue Required from Rates	182,917	1,783	641	1,383	155	3,962
Projected Rate of Return Before Increase	6.727%					6.940%
Projected Billing Units						
Kwh	2,014,529,000			55,941,000		
Kw Demand	3,304,802	273,550	273,550			
Bills	1,170,228				7,476	
Unit Cost of Service						
\$ per Kwh				0.025		
\$ per Kw Demand		6.52	2.34			
\$ per Customer Per Month					20.73	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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	Small Municipal Rate 40					Total Sm Municipal Rate 40
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	
Rate Base	520,229	711	175	7	389	1,282
Operating Income for Proposed Return	38,805	53	13	1	29	96
Current Operating Income	34,998	(62)	18	80	11	46
Increase in Operating Income	3,807	115	(5)	(79)	18	50
Related Taxes for Increase						
State & Federal Income Taxes	2,311	70	(3)	(48)	11	29
Total Increase in Revenue	6,118	185	(8)	(127)	29	79
Total Revenue Before Increase	186,308	7	50	234	79	370
Total Cost of Service Required from Rates	192,426	192	42	107	108	449
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	7	1	5	4	17
Revenue Required from Rates	182,917	185	41	102	104	432
Projected Rate of Return Before Increase	6.727%					3.588%
Projected Billing Units						
Kwh	2,014,529,000			4,076,000		
Kw Demand	3,304,802	9,468	9,468			
Bills	1,170,228				3,708	
Unit Cost of Service						
\$ per Kwh				0.025		
\$ per Kw Demand		19.54	4.33			
\$ per Customer Per Month					28.05	
Operating Income/Inverse of Federal income tax rate:						
Operating Income for Proposed Return:						

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	Municipal Lighting Primary Rate 41					Total Mun Lighting Pri Rate 41
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	
Rate Base	520,229	114	82	3	28	227
Operating Income for Proposed Return	38,805	9	6	0	2	17
Current Operating Income	34,998	(9)	(5)	51	(2)	34
Increase in Operating Income	3,807	18	11	(51)	4	(17)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	11	7	(31)	2	(12)
Total Increase in Revenue	6,118	29	18	(82)	6	(29)
Total Revenue Before Increase	186,308	1	0	126	0	127
Total Cost of Service Required from Rates	192,426	30	18	44	6	98
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	1	0	2	0	3
Revenue Required from Rates	182,917	29	18	42	6	95
Projected Rate of Return Before Increase	6.727%					14.978%
Projected Billing Units						
Kwh	2,014,529,000	1,719,000	1,719,000	1,719,000		
Kw Demand	3,304,802					
Bills	1,170,228					
Unit Cost of Service						
\$ per Kwh		0.017	0.010	0.024		
\$ per Kw Demand						
\$ per Customer Per Month						

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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	Municipal Lighting Secondary Rate 41					Total Mun Lighting Sec Rate 41
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	
Rate Base	520,229	1,139	1,278	31	2,192	4,640
Operating Income for Proposed Return	38,805	85	95	2	164	346
Current Operating Income	34,998	(100)	(82)	599	136	553
Increase in Operating Income	3,807	185	177	(597)	28	(207)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	112	108	(363)	17	(126)
Total Increase in Revenue	6,118	297	285	(960)	45	(333)
Total Revenue Before Increase	186,308	11	16	1,434	645	2,106
Total Cost of Service Required from Rates	192,426	308	301	474	690	1,773
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	11	16	24	645	696
Revenue Required from Rates	182,917	297	285	450	45	1,077
Projected Rate of Return Before Increase	6.727%					11.918%
Projected Billing Units						
Kwh	2,014,529,000	18,127,000	18,127,000	18,127,000		
Kw Demand	3,304,802					
Bills	1,170,228					
Unit Cost of Service						
\$ per Kwh		0.016	0.016	0.025		
\$ per Kw Demand						
\$ per Customer Per Month						

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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	Total North Dakota	Municipal Pumping Primary Rate 48			Total Mun Pumping Pri Rate 48	
		Demand Prod. & Trans.	Demand Distribution	Energy		Customer
Rate Base	520,229	2,056	645	24	28	2,753
Operating Income for Proposed Return	38,805	153	48	2	2	205
Current Operating Income	34,998	(179)	67	189	0	77
Increase in Operating Income	3,807	332	(19)	(187)	2	128
Related Taxes for Increase						
State & Federal Income Taxes	2,311	202	(12)	(114)	1	77
Total Increase in Revenue	6,118	534	(31)	(301)	3	205
Total Revenue Before Increase	186,308	20	184	658	1	863
Total Cost of Service Required from Rates	192,426	554	153	357	4	1,068
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	20	8	18	0	46
Revenue Required from Rates	182,917	534	145	339	4	1,022
Projected Rate of Return Before Increase	6.727%					2.797%
Projected Billing Units						
Kwh	2,014,529,000			13,894,000		
Kw Demand	3,304,802	35,805	35,805			
Bills	1,170,228				48	
Unit Cost of Service						
\$ per Kwh				0.024		
\$ per Kw Demand		14.91	4.05			
\$ per Customer Per Month					83.33	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

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 Cost of Service by Component  
 Projected 2017 - Reflecting Staff Recommended Adjustments  
 (000's)

	Total North Dakota	Municipal Pumping Secondary Rate 48			Customer	Total Mun Pumping Sec Rate 48
		Demand Prod. & Trans.	Demand Distribution	Energy		
Rate Base	520,229	3,802	1,350	43	659	5,854
Operating Income for Proposed Return	38,805	284	101	3	49	437
Current Operating Income	34,998	(331)	281	375	(36)	289
Increase in Operating Income	3,807	615	(180)	(372)	85	148
Related Taxes for Increase						
State & Federal Income Taxes	2,311	374	(109)	(226)	52	91
Total Increase in Revenue	6,118	989	(289)	(598)	137	239
Total Revenue Before Increase	186,308	38	613	1,250	47	1,948
Total Cost of Service Required from Rates	192,426	1,027	324	652	184	2,187
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	38	16	33	10	97
Revenue Required from Rates	182,917	989	308	619	174	2,090
Projected Rate of Return Before Increase	6.727%					4.937%
Projected Billing Units						
Kwh	2,014,529,000			25,168,000		
Kw Demand	3,304,802	91,118	91,118			
Bills	1,170,228				3,828	
Unit Cost of Service						
\$ per Kwh				0.025		
\$ per Kw Demand		10.85	3.38			
\$ per Customer Per Month					45.45	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

MONTANA-DAKOTA UTILITIES CO.  
 ELECTRIC UTILITY  
 NORTH DAKOTA  
 Embedded Class Cost of Service Study  
 Cost of Service by Component  
 Projected 2017 - Reflecting Staff Recommended Adjustments  
 (000's)

	Total North Dakota	Outdoor Lighting Rate 52			Total Outdoor Lighting Rate 52	
		Demand Prod. & Trans.	Demand Distribution	Energy		Customer
Rate Base	520,229	747	389	13	635	1,784
Operating Income for Proposed Return	38,805	56	29	1	47	133
Current Operating Income	34,998	(66)	(27)	324	1	232
Increase in Operating Income	3,807	122	56	(323)	46	(99)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	74	34	(196)	28	(60)
Total Increase in Revenue	6,118	196	90	(519)	74	(159)
Total Revenue Before Increase	186,308	8	4	715	209	936
Total Cost of Service Required from Rates	192,426	204	94	196	283	777
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	8	4	10	209	231
Revenue Required from Rates	182,917	196	90	186	74	546
Projected Rate of Return Before Increase	6.727%					13.004%
Projected Billing Units						
Kwh	2,014,529,000	7,437,000	7,437,000	7,437,000		
Kw Demand	3,304,802					
Bills	1,170,228					
Unit Cost of Service						
\$ per Kwh		0.026	0.012	0.025		
\$ per Kw Demand						
\$ per Customer Per Month						

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

MONTANA-DAKOTA UTILITIES CO.  
 ELECTRIC UTILITY  
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 Cost of Service by Component  
 Projected 2017 - Reflecting Staff Recommended Adjustments  
 (000's)

	Total North Dakota	Interruptible Demand Response Rate 38			Total IT Demand Response Rate 38	
		Demand Prod. & Trans.	Demand Distribution	Energy		Customer
Rate Base	520,229	3,917	1,169	54	16	5,156
Operating Income for Proposed Return	38,805	292	87	4	1	384
Current Operating Income	34,998	(343)	286	432	10	386
Increase in Operating Income	3,807	635	(199)	(428)	(9)	(2)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	386	(121)	(260)	(5)	1
Total Increase in Revenue	6,118	1,021	(320)	(688)	(14)	(1)
Total Revenue Before Increase	186,308	39	601	1,507	18	2,165
Total Cost of Service Required from Rates	192,426	1,060	281	819	4	2,164
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	39	15	41	0	95
Revenue Required from Rates	182,917	1,021	266	778	4	2,069
Projected Rate of Return Before Increase	6.727%					7.486%
Projected Billing Units						
Kwh	2,014,529,000			31,911,000		
Kw Demand	3,304,802	85,568	85,568			
Bills	1,170,228				36	
Unit Cost of Service						
\$ per Kwh				0.024		
\$ per Kw Demand		11.93	3.11			
\$ per Customer Per Month					111.11	

Operating Income/Inverse of Federal income tax rate:  
 Operating Income for Proposed Return:

**MONTANA-DAKOTA UTILITIES CO.  
 RECOMMENDED REVENUE INCREASE ALLOCATION  
 REFLECTING RECOMMENDED REVENUE REQUIREMENTS FROM STAFF WITNESS R. POLICH  
 EXCLUSIVE OF RENEWABLE RIDER AND TRANSMISSION RIDER RECOMMENDED ADJUSTMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017 (\$000)**

Line No. (a)	Item (b)	Total North Dakota (c)	Total Residential (d)	Total Small General (e)	Total Large General (f)	Total Lighting (g)	Total Municipal Pumping (h)
	<b>Operating Revenues</b>						
1	Sales Revenues	182,637	73,955	12,794	90,800	2,316	2,772
2	Other Revenues	3,671	1,585	217	977	853	39
3	<b>Total Operating Revenues</b>	<b>186,308</b>	<b>75,540</b>	<b>13,011</b>	<b>91,777</b>	<b>3,169</b>	<b>2,811</b>
	<b>Operating Expense</b>						
4	Cost of Fuel and Purchased Power	54,191	20,868	3,189	28,378	714	1,042
5	Other O&M Expense	52,325	25,454	4,141	21,131	792	807
6	<b>Total O&amp;M Expense</b>	<b>106,516</b>	<b>46,322</b>	<b>7,330</b>	<b>49,509</b>	<b>1,506</b>	<b>1,849</b>
7	Depreciation Expense	24,746	11,648	1,884	10,467	345	402
8	Taxes Other Than Income Taxes	6,392	3,029	491	2,678	93	101
9	Current Income Taxes - Fed. & State	13,656	3,249	886	9,022	406	93
10	<b>Total Operating Expenses</b>	<b>151,310</b>	<b>64,248</b>	<b>10,591</b>	<b>71,676</b>	<b>2,350</b>	<b>2,445</b>
11	<b>Projected Operating Income</b>	<b>34,998</b>	<b>11,292</b>	<b>2,420</b>	<b>20,101</b>	<b>819</b>	<b>366</b>
12	<b>Rate Base</b>	<b>520,229</b>	<b>243,214</b>	<b>39,651</b>	<b>222,106</b>	<b>6,651</b>	<b>8,607</b>
13	<b>Projected Rate of Return Before Revenue Increase</b>	<b>6.727%</b>	<b>4.643%</b>	<b>6.103%</b>	<b>9.050%</b>	<b>12.314%</b>	<b>4.252%</b>
14	Recommended Revenue Increase per Staff Witness R. Polich	515					
15	Percent Increase Over Current Sales Revenues	0.28%					
16	Maximum Increase (2.0 x System Increase)	0.56%					
17	Minimum Increase (0.5 x System Increase)	0.14%					
18	Recommended Revenue Allocation (% Increase)		0.43%	0.35%	0.15%	0.15%	0.55%
19	<b>Recommended Revenue Increase</b>	<b>515</b>	<b>316</b>	<b>45</b>	<b>136</b>	<b>3</b>	<b>15</b>
20	<b>Recommended Rate of Return After Increase</b>	<b>6.789%</b>	<b>4.724%</b>	<b>6.174%</b>	<b>9.088%</b>	<b>12.344%</b>	<b>4.357%</b>
21	<b>Recommended Relative Rate of Return (ND = 1.000)</b>	<b>1.000</b>	<b>0.696</b>	<b>0.909</b>	<b>1.339</b>	<b>1.818</b>	<b>0.642</b>

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**MONTANA-DAKOTA UTILITIES CO.  
 PROJECTED OPERATING INCOME AND RATE OF RETURN  
 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017 (\$000)**

<b>TOTAL NORTH DAKOTA</b>			
	<u>Before Additional Revenue Requirements</u>	<b>Additional Revenue Requirements</b>	<u>Reflecting Additional Revenue Requirements</u>
<b>Operating Revenues</b>			
Sales	\$182,637	<b>\$515</b>	\$183,152
Sales for Resale			-
Other	3,671		3,671
Total Revenues	186,308	515	186,823
<b>Operating Expenses</b>			
Operation and Maintenance			
Cost of Fuel & Purchased Power	54,191		54,191
Other O&M	77,071		77,071
Total O&M	131,262		131,262
Depreciation			0
Taxes Other Than Income	6,392		6,392
Current Income Taxes	13,656	195	13,851
Deferred Income Taxes	0		0
Total Expenses	151,310	195	151,505
Operating Income	\$34,998	\$320	\$35,318
Rate Base	\$520,229		\$520,229
<b>Rate of Return</b>			
	<b>6.727%</b>		<b>6.789%</b>

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**MONTANA-DAKOTA UTILITIES CO.  
 PROJECTED OPERATING INCOME AND RATE OF RETURN  
 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017 (\$000)**

<b>TOTAL RESIDENTIAL</b>			
	Before Additional Revenue Requirements	<b>Additional Revenue Requirements</b>	Reflecting Additional Revenue Requirements
<b>Operating Revenues</b>			
Sales	\$73,955	<b>\$316</b>	\$74,271
Sales for Resale			-
Other	1,585		1,585
Total Revenues	<u>75,540</u>	<u>316</u>	<u>75,856</u>
<b>Operating Expenses</b>			
<b>Operation and Maintenance</b>			
Cost of Fuel & Purchased Power	20,868		20,868
Other O&M	37,102		37,102
Total O&M	<u>57,970</u>		<u>57,970</u>
Depreciation			0
Taxes Other Than Income	3,029		3,029
Current Income Taxes	3,249	119	3,368
Deferred Income Taxes	0		0
Total Expenses	<u>64,248</u>	<u>119</u>	<u>64,367</u>
Operating Income	<u>\$11,292</u>	<u>\$197</u>	<u>\$11,489</u>
Rate Base	<u>\$243,214</u>		<u>\$243,214</u>
<b>Rate of Return</b>	<u><b>4.643%</b></u>		<u><b>4.724%</b></u>

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**MONTANA-DAKOTA UTILITIES CO.  
 PROJECTED OPERATING INCOME AND RATE OF RETURN  
 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017 (\$000)**

<b>TOTAL SMALL GENERAL</b>			
	Before Additional Revenue Requirements	<b>Additional Revenue Requirements</b>	Reflecting Additional Revenue Requirements
<b>Operating Revenues</b>			
Sales	\$12,794	<b>\$45</b>	\$12,839
Sales for Resale			-
Other	217		217
<b>Total Revenues</b>	<u>13,011</u>	<u>45</u>	<u>13,056</u>
<b>Operating Expenses</b>			
Operation and Maintenance			
Cost of Fuel & Purchased Power	3,189		3,189
Other O&M	6,025		6,025
<b>Total O&amp;M</b>	<u>9,214</u>		<u>9,214</u>
Depreciation			0
Taxes Other Than Income	491		491
Current Income Taxes	886	17	903
Deferred Income Taxes	0		0
<b>Total Expenses</b>	<u>10,591</u>	<u>17</u>	<u>10,608</u>
<b>Operating Income</b>	<u>\$2,420</u>	<u>\$28</u>	<u>\$2,448</u>
Rate Base	<u>\$39,651</u>		<u>\$39,651</u>
<b>Rate of Return</b>	<u>6.103%</u>		<u>6.174%</u>

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 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017 (\$000)**

<b>TOTAL LARGE GENERAL</b>			
	Before Additional Revenue Requirements	<b>Additional Revenue Requirements</b>	Reflecting Additional Revenue Requirements
<b>Operating Revenues</b>			
Sales	\$90,800	<b>\$136</b>	\$90,936
Sales for Resale			-
Other	977		977
Total Revenues	<u>91,777</u>	<u>136</u>	<u>91,913</u>
<b>Operating Expenses</b>			
Operation and Maintenance			
Cost of Fuel & Purchased Power	28,378		28,378
Other O&M	31,598		31,598
Total O&M	<u>59,976</u>		<u>59,976</u>
Depreciation			0
Taxes Other Than Income	2,678		2,678
Current Income Taxes	9,022	51	9,073
Deferred Income Taxes	0		0
Total Expenses	<u>71,676</u>	<u>51</u>	<u>71,727</u>
Operating Income	<u>\$20,101</u>	<u>\$85</u>	<u>\$20,186</u>
Rate Base	<u>\$222,106</u>		<u>\$222,106</u>
<b>Rate of Return</b>	<u><b>9.050%</b></u>		<u><b>9.088%</b></u>

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**MONTANA-DAKOTA UTILITIES CO.  
 PROJECTED OPERATING INCOME AND RATE OF RETURN  
 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017 (\$000)**

<b>TOTAL LIGHTING</b>			
	Before Additional Revenue Requirements	<b>Additional Revenue Requirements</b>	Reflecting Additional Revenue Requirements
<b>Operating Revenues</b>			
Sales	\$2,316	<b>\$3</b>	\$2,319
Sales for Resale			-
Other	853		853
Total Revenues	<u>3,169</u>	<u>3</u>	<u>3,172</u>
<b>Operating Expenses</b>			
Operation and Maintenance			
Cost of Fuel & Purchased Power	714		714
Other O&M	1,137		1,137
Total O&M	<u>1,851</u>		<u>1,851</u>
Depreciation			0
Taxes Other Than Income	93		93
Current Income Taxes	406	1	407
Deferred Income Taxes	0		0
Total Expenses	<u>2,350</u>	<u>1</u>	<u>2,351</u>
Operating Income	<u>\$819</u>	<u>\$2</u>	<u>\$821</u>
Rate Base	<u>\$6,651</u>		<u>\$6,651</u>
<b>Rate of Return</b>	<u><b>12.314%</b></u>		<u><b>12.344%</b></u>

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 PROJECTED OPERATING INCOME AND RATE OF RETURN  
 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017 (\$000)**

<b>TOTAL MUNICIPAL PUMPING</b>			
	Before Additional Revenue Requirements	<b>Additional Revenue Requirements</b>	Reflecting Additional Revenue Requirements
<b>Operating Revenues</b>			
Sales	\$2,772	<b>\$15</b>	\$2,787
Sales for Resale			-
Other	39		39
Total Revenues	<u>2,811</u>	<u>15</u>	<u>2,826</u>
<b>Operating Expenses</b>			
Operation and Maintenance			
Cost of Fuel & Purchased Power	1,042		1,042
Other O&M	1,209		1,209
Total O&M	<u>2,251</u>		<u>2,251</u>
Depreciation			0
Taxes Other Than Income	101		101
Current Income Taxes	93	6	99
Deferred Income Taxes	0		0
Total Expenses	<u>2,445</u>	<u>6</u>	<u>2,451</u>
Operating Income	<u>\$366</u>	<u>\$9</u>	<u>\$375</u>
Rate Base	<u>\$8,607</u>		<u>\$8,607</u>
<b>Rate of Return</b>	<u><b>4.252%</b></u>		<u><b>4.357%</b></u>

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MONTANA-DAKOTA UTILITIES CO.  
 BILLING COMPARISON AT VARIOUS USAGE LEVELS  
 RESIDENTIAL RATE 10

WINTER MONTH BILL, ASSUMING 30 BILLING DAYS  
 Present Rate vs. Proposed Rate with Declining Energy Block Charges

Line No.	kWh Usage	Present Rate		Proposed Rate - Declining Block		Increase/(Decrease)	
		Amount	¢ per kWh	Amount	¢ per kWh	Amount	Percent
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	0	\$10.50	-	\$19.50	-	\$9.00	85.7%
2	50	\$15.39	30.8	\$24.30	48.6	\$8.91	57.9%
3	100	\$20.28	20.3	\$29.11	29.1	\$8.83	43.5%
4	200	\$30.05	15.0	\$38.71	19.4	\$8.66	28.8%
5	300	\$39.83	13.3	\$48.32	16.1	\$8.49	21.3%
6	400	\$49.61	12.4	\$57.92	14.5	\$8.31	16.8%
7	500	\$59.39	11.9	\$67.53	13.5	\$8.14	13.7%
8	600	\$69.16	11.5	\$77.14	12.9	\$7.98	11.5%
9	700	\$78.94	11.3	\$86.74	12.4	\$7.80	9.9%
10	800	\$87.22	10.9	\$94.85	11.9	\$7.63	8.7%
11	900	\$93.99	10.4	\$101.45	11.3	\$7.46	7.9%
12	1,000	\$100.77	10.1	\$108.06	10.8	\$7.29	7.2%
13	1,200	\$114.32	9.5	\$121.27	10.1	\$6.95	6.1%
14	1,250	\$117.71	9.4	\$124.58	10.0	\$6.87	5.8%
15	1,500	\$134.66	9.0	\$141.09	9.4	\$6.43	4.8%
16	1,750	\$151.60	8.7	\$157.61	9.0	\$6.01	4.0%
17	2,000	\$168.54	8.4	\$174.12	8.7	\$5.58	3.3%
18	2,500	\$202.43	8.1	\$207.15	8.3	\$4.72	2.3%
19	3,000	\$236.31	7.9	\$240.18	8.0	\$3.87	1.6%
20	3,500	\$270.20	7.7	\$273.21	7.8	\$3.01	1.1%
21	4,000	\$304.08	7.6	\$306.24	7.7	\$2.16	0.7%

**RATE CHARGES**

	Present Rates	Proposed Rates
Basic Service Charge	\$0.35 per day	\$0.65 per day
Energy Charges:		
First 750 kWh	\$0.05304 per kWh	\$0.06066 per kWh
Over 750 kWh	\$0.02304 per kWh	\$0.03066 per kWh
Generation Rider	\$0.00500 per kWh	\$0.00000 per kWh
Environmental Rider	\$0.00396 per kWh	\$0.00000 per kWh
Transmission Rider	\$0.00329 per kWh	\$0.00298 per kWh
Renewable Rider	\$0.00712 per kWh	\$0.00706 per kWh
Base Fuel & Purchased Power	\$0.02536 per kWh	\$0.02536 per kWh

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**MONTANA-DAKOTA UTILITIES CO.  
 BILLING COMPARISON AT VARIOUS USAGE LEVELS  
 RESIDENTIAL RATE 10**

**WINTER MONTH BILL, ASSUMING 30 BILLING DAYS  
 Present Rate vs. Proposed Rate with Flat Energy Charge**

Line No.	kWh Usage	Present Rate		Proposed Rate - Declining Block		Increase/(Decrease)	
		Amount	¢ per kWh	Amount	¢ per kWh	Amount	Percent
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	0	\$10.50	-	\$19.50	-	\$9.00	85.7%
2	50	\$15.39	30.8	\$23.72	47.4	\$8.33	54.1%
3	100	\$20.28	20.3	\$27.94	27.9	\$7.66	37.8%
4	200	\$30.05	15.0	\$36.38	18.2	\$6.33	21.1%
5	300	\$39.83	13.3	\$44.82	14.9	\$4.99	12.5%
6	400	\$49.61	12.4	\$53.26	13.3	\$3.65	7.4%
7	500	\$59.39	11.9	\$61.70	12.3	\$2.31	3.9%
8	600	\$69.16	11.5	\$70.14	11.7	\$0.98	1.4%
9	700	\$78.94	11.3	\$78.58	11.2	(\$0.36)	-0.5%
10	800	\$87.22	10.9	\$87.02	10.9	(\$0.20)	-0.2%
11	900	\$93.99	10.4	\$95.46	10.6	\$1.47	1.6%
12	1,000	\$100.77	10.1	\$103.90	10.4	\$3.13	3.1%
13	1,200	\$114.32	9.5	\$120.78	10.1	\$6.46	5.7%
14	1,250	\$117.71	9.4	\$125.00	10.0	\$7.29	6.2%
15	1,500	\$134.66	9.0	\$146.10	9.7	\$11.44	8.5%
16	1,750	\$151.60	8.7	\$167.20	9.6	\$15.60	10.3%
17	2,000	\$168.54	8.4	\$188.30	9.4	\$19.76	11.7%
18	2,500	\$202.43	8.1	\$230.50	9.2	\$28.07	13.9%
19	3,000	\$236.31	7.9	\$272.70	9.1	\$36.39	15.4%
20	3,500	\$270.20	7.7	\$314.90	9.0	\$44.70	16.5%
21	4,000	\$304.08	7.6	\$357.10	8.9	\$53.02	17.4%

**RATE CHARGES**

	<u>Present Rates</u>	<u>Proposed Rates</u>
Basic Service Charge	\$0.35 per day	\$0.65 per day
Energy Charges:		
First 750 kWh	\$0.05304 per kWh	\$0.04900 per kWh
Over 750 kWh	\$0.02304 per kWh	\$0.04900 per kWh
Generation Rider	\$0.00500 per kWh	\$0.00000 per kWh
Environmental Rider	\$0.00396 per kWh	\$0.00000 per kWh
Transmission Rider	\$0.00329 per kWh	\$0.00298 per kWh
Renewable Rider	\$0.00712 per kWh	\$0.00706 per kWh
Base Fuel & Purchased Power	\$0.02536 per kWh	\$0.02536 per kWh

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MONTANA-DAKOTA UTILITIES CO.  
 BILLING COMPARISON AT VARIOUS USAGE LEVELS  
 SMALL GENERAL SERVICE RATE 20

WINTER MONTH BILL, ASSUMING 30 BILLING DAYS  
 Present Rate vs. Proposed Rate with Declining Energy Block Charges

Line No.	kWh Usage	Present Rate		Proposed Rate - Declining Block		Increase/(Decrease)	
		Amount	¢ per kWh	Amount	¢ per kWh	Amount	Percent
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	0	\$21.00	-	\$25.20	-	\$4.20	20.0%
2	50	\$25.71	51.4	\$30.43	60.9	\$4.72	18.4%
3	100	\$30.43	30.4	\$35.65	35.7	\$5.22	17.2%
4	200	\$39.86	19.9	\$46.11	23.1	\$6.25	15.7%
5	300	\$49.28	16.4	\$56.56	18.9	\$7.28	14.8%
6	400	\$58.71	14.7	\$67.02	16.8	\$8.31	14.2%
7	500	\$68.14	13.6	\$77.47	15.5	\$9.33	13.7%
8	600	\$77.57	12.9	\$87.92	14.7	\$10.35	13.3%
9	700	\$87.00	12.4	\$98.38	14.1	\$11.38	13.1%
10	800	\$94.50	11.8	\$107.33	13.4	\$12.83	13.6%
11	900	\$100.09	11.1	\$114.79	12.8	\$14.70	14.7%
12	1,000	\$105.67	10.6	\$122.24	12.2	\$16.57	15.7%
13	1,200	\$116.84	9.7	\$137.15	11.4	\$20.31	17.4%
14	1,250	\$119.64	9.6	\$140.88	11.3	\$21.24	17.8%
15	1,500	\$133.60	8.9	\$159.51	10.6	\$25.91	19.4%
16	1,750	\$147.56	8.4	\$178.15	10.2	\$30.59	20.7%
17	2,000	\$161.52	8.1	\$196.78	9.8	\$35.26	21.8%
18	2,500	\$189.45	7.6	\$234.05	9.4	\$44.60	23.5%
19	3,000	\$217.37	7.2	\$271.32	9.0	\$53.95	24.8%
20	3,500	\$245.30	7.0	\$308.59	8.8	\$63.29	25.8%
21	4,000	\$273.22	6.8	\$345.86	8.6	\$72.64	26.6%

**RATE CHARGES**

	Present Rates	Proposed Rates
Basic Service Charge	\$0.70 per day	\$0.84 per day
Energy Charges:		
First 750 kWh	\$0.06147 per kWh	\$0.07212 per kWh
Over 750 kWh	\$0.02304 per kWh	\$0.04212 per kWh
Generation Rider	\$0.00349 per kWh	\$0.00000 per kWh
Environmental Rider	\$0.00396 per kWh	\$0.00000 per kWh
Renewable Rider	\$0.00000 per kWh	\$0.00706 per kWh
Base Fuel & Purchased Power	\$0.02536 per kWh	\$0.02536 per kWh

MONTANA-DAKOTA UTILITIES CO.  
 BILLING COMPARISON AT VARIOUS USAGE LEVELS  
 SMALL GENERAL SERVICE RATE 20

WINTER MONTH BILL, ASSUMING 30 BILLING DAYS  
 Present Rate vs. Proposed Rate with Flat Energy Charge

Line No.	kWh Usage	Present Rate		Proposed Rate - Declining Block		Increase/(Decrease)	
		Amount	¢ per kWh	Amount	¢ per kWh	Amount	Percent
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	0	\$21.00	-	\$25.20	-	\$4.20	20.0%
2	50	\$25.71	51.4	\$29.65	59.3	\$3.94	15.3%
3	100	\$30.43	30.4	\$34.10	34.1	\$3.67	12.1%
4	200	\$39.86	19.9	\$42.99	21.5	\$3.13	7.9%
5	300	\$49.28	16.4	\$51.89	17.3	\$2.61	5.3%
6	400	\$58.71	14.7	\$60.79	15.2	\$2.08	3.5%
7	500	\$68.14	13.6	\$69.69	13.9	\$1.55	2.3%
8	600	\$77.57	12.9	\$78.58	13.1	\$1.01	1.3%
9	700	\$87.00	12.4	\$87.48	12.5	\$0.48	0.6%
10	800	\$94.50	11.8	\$96.38	12.0	\$1.88	2.0%
11	900	\$100.09	11.1	\$105.27	11.7	\$5.18	5.2%
12	1,000	\$105.67	10.6	\$114.17	11.4	\$8.50	8.0%
13	1,200	\$116.84	9.7	\$131.96	11.0	\$15.12	12.9%
14	1,250	\$119.64	9.6	\$136.41	10.9	\$16.77	14.0%
15	1,500	\$133.60	8.9	\$158.66	10.6	\$25.06	18.8%
16	1,750	\$147.56	8.4	\$180.90	10.3	\$33.34	22.6%
17	2,000	\$161.52	8.1	\$203.14	10.2	\$41.62	25.8%
18	2,500	\$189.45	7.6	\$247.63	9.9	\$58.18	30.7%
19	3,000	\$217.37	7.2	\$292.11	9.7	\$74.74	34.4%
20	3,500	\$245.30	7.0	\$336.60	9.6	\$91.30	37.2%
21	4,000	\$273.22	6.8	\$381.08	9.5	\$107.86	39.5%

**RATE CHARGES**

	Present Rates	Proposed Rates
Basic Service Charge	\$0.70 per day	\$0.84 per day
Energy Charges:		
First 750 kWh	\$0.06147 per kWh	\$0.05655 per kWh
Over 750 kWh	\$0.02304 per kWh	\$0.05655 per kWh
Generation Rider	\$0.00349 per kWh	\$0.00000 per kWh
Environmental Rider	\$0.00396 per kWh	\$0.00000 per kWh
Renewable Rider	\$0.00000 per kWh	\$0.00706 per kWh
Base Fuel & Purchased Power	\$0.02536 per kWh	\$0.02536 per kWh

BEFORE THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Montana-Dakota Utilities Co.,  
a Division of MDU Resources Group, Inc.  
2016 Electric Rate Increase Application

Case No. PU-16-666

DIRECT TESTIMONY  
OF  
RICHARD A. POLICH, P.E.

ON BEHALF OF THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION  
ADVOCACY STAFF

February 24, 2017

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1 **Q. Please state your name and place of employment.**

2 A. My name is Richard A. Polich. I am employed by GDS Associates, Inc.  
3 (“GDS”), and my office is located at 1850 Parkway Place, Suite 800,  
4 Marietta, Georgia 30067.

5 **Q. What position do you hold?**

6 A. I hold the position of Managing Director.

7 **Q. On whose behalf are you submitting this testimony?**

8 A. I am submitting this testimony on behalf of North Dakota Public Service  
9 Commission Advocacy Staff (“Staff”).

10 **Q. What is your educational background?**

11 A. I graduated from the University of Michigan - Ann Arbor in August 1979  
12 with a Bachelor of Science Engineering Degree in Nuclear Engineering,  
13 and a Bachelor of Science Engineering Degree in Mechanical  
14 Engineering.

15 In May 1990, I received a Master of Business Administration from the  
16 University of Michigan - Ann Arbor.

17 **Q. Please describe your work experience.**

18 A. In my role as both employee and consultant, I have had over 37 years of  
19 work experience in the energy sector, performing duties and services for a  
20 myriad of companies and organizations, and representing the interests of  
21 private and public constituencies throughout the country.

1 In May 1978, I joined Commonwealth Associates, Inc., located in Jackson,  
2 Michigan, as a Graduate Engineer and worked on several plant  
3 modification and new plant construction projects.

4 In May 1979, I joined Consumers Power Inc. (now called Consumers  
5 Energy), located in Jackson, Michigan, as an Associate Engineer in the  
6 Plant Engineering Services Department.

7 In April 1980, I transferred to the Midland Nuclear Project and progressed  
8 through various job classifications to Senior Engineer. I also participated in  
9 the initial design evaluation of the Midland Cogeneration Plant.

10 In July 1987, I transferred to the Market Services Department as a Senior  
11 Engineer and reached the level of Senior Market Representative. While in  
12 this department, I analyzed the economic and engineering feasibility of  
13 customer cogeneration projects.

14 In July 1992, I transferred to the Rates and Regulatory Affairs Department  
15 of Consumers Energy as a Principal Rate Analyst. In that capacity, I  
16 performed studies relating to all facets of development and design of  
17 Consumers Energy's retail gas and electric rates and electric wholesale  
18 rates. During this period, I was heavily involved in the development of  
19 Consumers Energy's Direct Access program and Consumers Energy's  
20 Retail Open Access program. I also participated in the development of  
21 Consumers Energy's revenue forecast.

1 In March 1998, I joined Nordic Energy, LLC (“Nordic”), located in Ann  
2 Arbor, Michigan, as Vice President in charge of marketing and sales. My  
3 responsibilities included all aspects of obtaining new customers and  
4 enabling Nordic to supply electricity to those customers. In May 2000, my  
5 responsibilities shifted to Operations and Regulatory Affairs. My  
6 Operations responsibilities included management of supply purchases,  
7 transmission services, and development of new power projects. My  
8 Regulatory Affairs responsibilities included overseeing regulatory and  
9 legislation issues for the company.

10 In March 2003, I formed Energy Options & Solutions, based in Ann Arbor,  
11 Michigan, as a consulting concern focusing on providing engineering  
12 services and regulatory support. Through my work with Energy Options &  
13 Solutions, I gained extensive experience consulting in the areas of project  
14 development and economic analysis with renewable energy companies  
15 across the country, including: Noble Environmental Power located in  
16 Centerbrook, Connecticut; Third Planet Windpower, LLC located in Palm  
17 Beach Gardens, Florida; TradeWind Energy, LLC located in Lenexa,  
18 Kansas; Windlab Developments USA located in Canberra, Australian  
19 Capital Territory, Australia; and Matinee Energy Inc. located in Tucson,  
20 Arizona, among others.

21 Other examples of my consulting work have included evaluation of the  
22 Arkansas Weatherization Assistance Program for the Arkansas Energy

1 Office, and providing the West Michigan Prosperity Alliance with an  
2 evaluation of the business opportunities for Western Michigan businesses  
3 in the renewable energy business sector.

4 In 2007, I served as primary author of the report on the economic impacts  
5 of renewable portfolio standards and energy efficiency programs for the  
6 Department of Environmental Quality – State of Michigan.

7 In 2011, I joined KEMA, Inc. (“KEMA”) located in Burlington,  
8 Massachusetts, as a Service Line Leader responsible for developing its  
9 renewable energy consulting business. While at KEMA, I performed  
10 multiple renewable energy studies for the Electric Power Research  
11 Institute, including a renewable energy options study for the country of  
12 Saint Maarten (a constituent country of the Kingdom of the Netherlands). I  
13 also assisted Lake Erie Energy Development Corporation in its successful  
14 application to the U.S. Department of Energy for a multi-million dollar grant  
15 to develop an offshore wind project in Lake Erie.

16 In 2013, I joined CLEAResult located in Little Rock, Arkansas, as Director  
17 of Operations. My primary responsibility involved supporting program  
18 operations in assisting the company’s Arkansas unit to successfully meet  
19 a 400% increase in energy efficiency goals that it managed for Entergy. I  
20 was also responsible for managing the company’s natural gas energy  
21 efficiency programs in the State of Oklahoma.

1 In 2015, I joined the Georgia office of GDS Associates, Inc., a consulting  
2 group focusing on utility engineering and consulting services, as Managing  
3 Director in its Generation Services area.

4 A copy of my Curriculum Vitae is attached hereto and incorporated herein  
5 as Exhibit PSC-1.

6 **Q. Do you have any professional registrations?**

7 **A.** Yes, I am a registered Professional Engineer in Michigan and hold a  
8 LEED Green Associate credential from the U.S. Green Building Council.

9 **Q. Have you published any papers?**

10 **A.** Yes, I have authored the following publications:

- 11 • Engineering and Economic Evaluation of Offshore Wind Plant  
12 Performance and Cost Data, 2011, Produced for the Electric Power  
13 Research Institute, KEMA, Inc.
- 14 • Island of Saint Maarten Sustainable Energy Study, 2012, Produced for the  
15 Cabinet of Ministry VROMI, KEMA Inc.
- 16 • A Study of Economic Impacts from the Implementation of a Renewable  
17 Portfolio Standard and an Energy Efficiency Program in Michigan, 2007,  
18 Produced for the Michigan Department of Environmental Quality
- 19 • Alternative and Renewable Energy Cluster Analysis, 2007, Produced for  
20 the West Michigan Strategic Alliance and The Right Place

1 **Q. Have you testified in any other regulatory proceedings?**

2 **A.** Yes, I have testified before the Michigan Public Service Commission on  
3 multiple occasions as a representative of Consumers Energy, and on  
4 behalf of Energy Michigan. I testified before the North Dakota Public  
5 Service Commission (“Commission”) on behalf of the Staff in Case No.  
6 PU-15-96, “In the Matter of Northern States Power Company’s Advance  
7 Determination of Prudence for its 345 MW Power Purchase Agreement  
8 with Mankato Energy Center”. In January 2016, I testified on behalf of  
9 SunEdison, Inc. in Docket No. 2015-0022 before the Public Utilities  
10 Commission of Hawaii, In the Matter of the Application of Hawaiian  
11 Electric Company, Inc. Hawai’i Electric Company, Inc., Maui Electric  
12 Company, Limited and NextEra Energy, Inc. for Approval of the Proposed  
13 Change of Control & Related Matters” (NextEra sought to purchase  
14 Hawaiian Electric, et all.). Attached hereto and incorporated herein as  
15 Exhibit PSC-2, is a list of proceedings detailing my prior participation as a  
16 testifying witness.

17 **Testimony Purpose and Summary**

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

19 **A.** The North Dakota Public Service Commission Advocacy Staff (“Staff”)  
20 hired GDS Associates, Inc. (“GDS”) to provide an analysis,  
21 recommendations and testimony in regard to Montana-Dakota Utilities

1 Co., a Division of MDU Resources Group, Inc. (MDU) 2016 Electric Rate  
2 Increase Application. My testimony will cover five areas, including;  
3 Proposal for overall rate of return; Adjustments to electric rate base; Cost  
4 of Lewis & Clark Reciprocating Internal Combustion Engine Project ("RICE  
5 Project"); Decommissioning Expense; and Revenue Requirement.

6 **Q. Please summarize your testimony.**

7 **A.** My testimony addresses MDU's overall rate of return, adjustments to plant  
8 in service and revenue requirement. I am recommending that the  
9 Commission base MDU's rate increase using the 2017 Projected Test  
10 Year based upon 2016-year end actual cost of service provided in  
11 Discovery Response 1.1. I further recommend the Commission approve  
12 an overall rate of return of 6.789% on plant in service based upon an  
13 8.53% return on equity. My testimony includes several disallowances in  
14 MDU's proposed plant in service resulting in a Project 2017 Rate Base of  
15 \$520,229,030, excluding wind resources. Last, I am recommending the  
16 Commission approve adjustment to MDU revenues (see Exhibit PSC-3)  
17 as follows:

18	1. Base Rate Revenue Increase:	\$515,316
19	2. The Renewable Rider Decrease:	\$1,775,588
20	3. Transmission Cost Adjustment Revenue Decrease:	\$674,367

1    **Q.    What are your other key Commission recommendations in this**  
2    **proceeding?**

3    I am recommending the following additional changes to MDU's rate  
4    increase request:

5           1. MDU's proposal for collection of decommissioning funds to be  
6           used for the decommissioning of existing plants should be  
7           rejected. The accounting treatment proposed by MDU places all  
8           the risk with the North Dakota ratepayers and all the rewards  
9           with MDU. MDU would be allowed to claim the revenue from the  
10          decommissioning expense as revenue and profit without any  
11          corresponding liability, resulting in additional shareholder profits.  
12          In the event of MDU over collection of funds to finance  
13          decommissioning, ratepayer's refunds would be less than the  
14          amount paid in to the fund (see page 26 of my testimony). This  
15          change reduces MDU annual revenue requirement by an  
16          estimated \$1,900,145.

17          2. MDU capitalization for recovery of losses on employee housing,  
18          should be disallowed. First, accounting treatment for this type of  
19          cost should be as an O&M expense in the years in which the  
20          cost occurred. Second, if this was not for temporary housing  
21          associated with employees being temporarily located at a job  
22          site, it is not recoverable. Third, MDU had other options of

1 supplying employees with housing which would have resulted in  
2 less cost (see page 30 of my testimony). This change reduces  
3 MDU annual revenue requirement by an estimated \$95,003.

4 3. Reduced incentive compensation and bonuses by 60% of the  
5 amount MDU forecasted to be consistent with Commission  
6 decision in Case PU-10-124 (see page 31 of my testimony).  
7 Incentive compensation and bonuses are established to  
8 improve company performance with the intention of benefiting  
9 company shareholders. Ratepayers should not be required to  
10 pay these costs because they do not provide any benefit to  
11 ratepayers.

12 4. \$ 12.27 million of MDU's cost for the Lewis & Clark RICE  
13 Project should be disallowed. This project was almost 70%  
14 higher than costs for similar types of generation resources.  
15 MDU's justification of an expedited project completion schedule,  
16 is not valid because MDU had opportunities to mitigate the  
17 situation and/or alternative options (see page 32 of my  
18 testimony). This change reduces MDU annual revenue  
19 requirement by an estimated \$1,460,482.

20 **Q. How is your testimony organized?**

21 **A. I have organized my testimony into the following sections:**

- 1           1. **Overall Rate of Return** – Calculation of return on equity (ROE) and  
2           overall rate of return (ROR).  
3           2. **Decommissioning Expense** – Address MDU’s request to include cost  
4           of decommissioning of future retired generation facilities in rate base.  
5           3. **Other Adjustments to Electric Rate Base** – Recommendations for  
6           adjustments to costs incorporated into electric rate base.  
7           4. **Lewis & Clark RICE Project** – Review of the need, timing and cost of  
8           this generation resource.  
9           5. **Revenue Requirement** – Calculate MDU’s revenue requirement and  
10          revenue deficit

11   **Q. Have you prepared any Exhibits?**

12   **A. Yes, the following is a list of Exhibits included with my testimony:**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
PSC-1	Richard A. Polich Curriculum Vitae
PSC-2	Regulatory Proceedings Testimony List
PSC-3	2017 Projected Operating Income and Rate of Return
PSC-4	DCF Calculation
PSC-5	Example of Flotation Cost Over Recovery
PSC-6	Decommissioning Cost to Montana Ratepayers
PSC-7	List of Similar Small Power Project Costs

1 **Q. Are you sponsoring any Revised Statements?**

2 A. Yes. Since we are recommending basing MDU's rate increase on a 2017  
3 Projected Test Year based upon 2016-year end actuals, all of MDU's Filed  
4 Statements need to be revised. I am sponsoring those statements I used  
5 in developing my revised plant in service and income statement. This  
6 includes Statements A, B, G, I and J.

7 **Overall Rate of Return**

8 **Q. What is the definition of cost of common equity?**

9 A. The cost of common equity or Return on Equity (ROE) is often defined as  
10 the compensation the market demands in exchange for owning the asset  
11 and bearing the risk of ownership. It is a percentage applied to the  
12 common equity portion of a utility's capital to calculate the utility's potential  
13 gross profit. It is a component of a utility's Rate of Return (ROR), which  
14 also includes interest on debt and dividends on preferred stock.

15 **Q. What was the basis for your method of calculating the ROE?**

16 A. There are several legal cases which establish the criteria and standards  
17 for determining the ROE. The criteria incorporated into my calculations  
18 were based upon standards set in the U. S. Supreme Court decisions in  
19 *Bluefield Waterworks & Improvement Co. v. Public Service Commission of*  
20 *West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*"), and *Federal Power*  
21 *Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"). This

1 establishes that ROE should be commensurate with the returns on  
2 investments in other enterprises having corresponding risks and should be  
3 sufficient to assure confidence in the financial integrity of the enterprise so  
4 as to maintain its credit and to attract capital.

5 **Q. Describe your approach to determining the appropriate rate of return**  
6 **on common equity for MDU.**

7 A. My first step was a review of MDU's witness, J. Stephen Gaske's  
8 testimony, exhibits and review of various discovery responses regarding  
9 cost of common equity based upon his Discounted Cash Flow analysis.  
10 Second, I have reviewed the cost of common equity testimony of  
11 witnesses in other MDU proceedings and various decisions of regulatory  
12 agencies. Last, I conducted my own analysis based upon data that better  
13 reflects the requirements of investors willing to risk capital in the equities  
14 market.

15 **Q. Do you agree with the methodology used by Mr. Gaske in his direct**  
16 **testimony?**

17 A. Mr. Gaske's use of Discounted Cash Flow ("DCF") analysis is the  
18 appropriate model for calculating return on common equity. I do not agree  
19 with his approach to the determinates used within that model or his  
20 calculations. Specifically, his selection of utilities used in the DCF  
21 calculation was too small, resulting in a statistically inferior sample set  
22 (see page 23 of my testimony). Mr. Gaske's application of a flotation cost

1 (see page 15 of my testimony) adjustment factor is inappropriate. In  
2 addition, he used the wrong quarterly dividend growth factor multiplier  
3 (see page 14 of my testimony).

4 **Q. Is the 10.0% ROE presented by Mr. Gaske a just and reasonable ROE**  
5 **for MDU?**

6 A. No. First, Mr. Gaske's assumption that the market does not already factor  
7 in investor anticipation of increased interest rates is not realistic, as I  
8 discuss in my testimony, starting on page 18. Second, the flotation cost  
9 adjustment is inappropriate since MDU has no intention of raising  
10 additional capital from common stock issuances and these costs are  
11 already included in MDU's current capital structure. Third, Mr. Gaske  
12 chose a select group of utilities which were based upon unnecessarily  
13 restrictive criteria resulting in a very small sample size.

14 **Q. What DCF methodology have you employed in calculating an**  
15 **appropriate ROE for MDU common equity?**

16 A. I have employed a readily accepted methodology utilized in various state  
17 and federal regulatory proceedings. I applied the Federal Energy  
18 Regulatory Commission (FERC) two-step DCF methodology, as outlined  
19 in FERC Opinion No. 531, to a representative group of national utilities.  
20 The DCF model is based upon the principle that rational investors  
21 evaluate the risks and expected returns of securities in capital markets  
22 and establish a price for a particular security which adequately



1 Markets reflect the timing of dividends in stock prices, resulting in dividend  
2 yield calculation of the DCF calculation also reflecting the timing of  
3 dividends. Mr. Gaske's argument of inflating the dividend multiplier to  
4 reflect an average of the timing for the payment of dividends results in  
5 double counting for market timing.

6 **Q. How did you determine the long-term US economic growth rate?**

7 A. The long-term US economic growth rate I used is based upon an average  
8 of long-term GDP data from Energy Information Administration, Social  
9 Security Administration and HIS Global Insights. The expected long-term  
10 US economic growth rate used in my DCF calculation is shown in Exhibit  
11 PSC-4.

12 **Q. Why do you feel it is inappropriate to include a "flotation Cost  
13 Adjustment" in the ROE calculation?**

14 A. In Mr. Gaske's testimony (page 20, lines 4-9), he defines "flotation costs"  
15 to be the cost associated with the issuance of "new common equity". Mr.  
16 Gaske then goes on to state that his "flotation cost adjustment" should be  
17 applied to "... the entire common equity investment ..." (Mr. Gaske's  
18 testimony, page 21, line 8). This inclusion of flotation costs in the ROE  
19 calculation would result in double recovery of costs and compensate MDU  
20 for costs they are not likely to incur. In addition, the 3.2% flotation costs  
21 Mr. Gaske used (Mr. Gaske's testimony, page 20, line 13), is not realistic  
22 because the cost of new equity depends upon the amount of equity being

1 raised and the manner in which it is being raised. In fact, MDU stated in  
2 Discovery Response 5.1 that in 2015 it received 115 million in equity  
3 which did not incur any issuance costs. The flotation costs of MDU's 2014  
4 common stock offering was approximately 1% (Discovery Response 2.9),  
5 much lower than Mr. Gaske's 3.2%. Applying the 3.2% flotation cost  
6 adjustment would result in MDU receiving revenues from North Dakota  
7 ratepayers for costs it had not incurred.

8 Mr. Gaske's position that flotation costs should be applied to existing  
9 equity because there is the potential for the company to issue new  
10 common equity is also double recovery. Any flotation costs for existing  
11 common equity has already been paid for by MDU ratepayers and is  
12 reflected in MDU's capital cost structure. In the event MDU elects to issue  
13 future common equity, MDU can request recovery of the cost of issuing  
14 new common equity in a future rate proceeding. MDU stated in Discovery  
15 Response 2.9 that flotation costs have not been included for recovery in  
16 previous rate proceedings and the equity recorded on its books is net of  
17 issuance costs.

18 Last, utilities very seldom issue new stock to raise common equity, funding  
19 operations and capital requirements from earnings and recovery of initial  
20 capital investment through their rates. MDU's current capital requirements  
21 do not appear to indicate a need to raise additional capital, because the  
22 amount recovered in rates through depreciation will cover the cost of

1 expected capital improvements. In Discovery Response 2.9 states that  
2 MDU does not have any plans to issue new common equity to support  
3 operations. In addition, MDU's debt to equity ratio is well within the  
4 expected D/E ratio of public utilities, thus additional equity is not needed.  
5 In summary, MDU is unlikely to incur flotation costs of issuing new equity  
6 in the near future. If they do issue new equity, MDU can attempt to recover  
7 the common equity issuance costs through a future regulatory proceeding.

8 **Q. Would Mr. Gaske's flotation cost adjustment recover the appropriate**  
9 **amount of flotation costs?**

10 **A.** No. The multiplication of the investor required return by the flotation cost  
11 adjustment is wrong mathematically and would result in MDU over  
12 recovering the flotation costs by 64%. I have provided an example of the  
13 flotation cost recovery proposed by Mr. Gaske in Exhibit PSC-5. The over  
14 recover occurs because the 3.2% flotation cost adjustment to is applied  
15 each year over the life of the asset. Using Mr. Gaske's approach of  
16 multiplying the ROE by the flotation cost adjustment and applying over the  
17 life of asset would result in ratepayers paying the total actual flotation  
18 costs by the end of year 16. This leaves the utility an additional 24 years  
19 of excess flotation costs recovery which results in unjustified profits. The  
20 ratepayer is much better off paying the flotation costs at the time the MDU  
21 incurs the need to increase equity. *It is my recommendation that the*  
22 *Commission should never include a flotation cost adjustment in the*

1           *calculation of cost of capital because it will always result in excessive*  
2           *recovery of flotation costs.*

3   **Q.   Do you agree with Mr. Gaske's position that current market**  
4           **conditions are artificial and not normal?**

5   **A.   No. Mr. Gaske's position is based primarily upon the Federal Reserve's**  
6           **Open Market Committee (FOMC) monetary policy as of September 16,**  
7           **2016. First, the Federal Reserve raised interest rates by 25 basis points**  
8           **on December 14, 2016. Second the FOMC has indicated it is inclined to**  
9           **raise rates up to three times this year. Third, the consumer-price-index**  
10           **has risen faster over the last few months, indicating a return to normal**  
11           **inflation levels. Fourth, markets reflect not only existing data but**  
12           **anticipated market performance. An indication of market anticipation can**  
13           **be seen in Treasury Bond yields, where the 10-year bond yield has risen**  
14           **from 1.63% in February of last year to 2.51%, a 54% increase in bond**  
15           **yields. Markets are reflecting anticipation of increased Federal Reserve**  
16           **interest rate hikes and higher inflation rates.**  
17           **Last, the definition of "normal" markets is the equivalent of arguing who is**  
18           **the best baseball player of all time. The conditions of the game of baseball**  
19           **at the time the game is played is a key determinate in the performance of**  
20           **a player. Changes in the game of baseball make it impossible to**  
21           **determine how a player in the 1940s would perform in today's game, too**  
22           **many aspects of the game have changed. The situation is the same with**

1 financial markets and company performance. Market conditions are  
2 always “normal” during the time at which those market conditions exist.  
3 Yes, things like market manipulation by a few players, can skew a market  
4 for a short time, but by definition the market still defines the normal  
5 condition at the time of that market. Today’s investors are more  
6 sophisticated, have access to more data and more analytical tools than  
7 ever before. They have the ability to find unusual circumstances within  
8 markets and can exploit those conditions, but usually only for very short  
9 period of time.

10 Today’s market conditions reflect future expectations of performance of  
11 the US economy and investors are pricing those factors into utility stock  
12 value. In addition, while some have suggested that the current relatively  
13 low capital costs are somehow aberrational or artificial, prominent  
14 economists like former Federal Reserve Chairman Benjamin Bernanke,  
15 former Treasury Secretary Lawrence Summers, and Nobel Prize winning  
16 economist Paul Krugman dispel these suggestions and express views in  
17 line with the expectation for continued relatively low long-term capital  
18 costs. For example, in his March 30, 2015 blog entitled “Why are interest  
19 rates so low?” Dr. Bernanke explained:

20 ***Low interest rates are not a short-term aberration,***  
21 ***but part of a long-term trend. As the figure below***  
22 ***shows, ten-year government bond yields in the United***  
23 ***States were relatively low in the 1960s, rose to a peak***

1                   above 15 percent in 1981, and have been declining  
2                   ever since. (Emphasis added.)

3                   The figure that Dr. Bernanke presents is a graph of 10-year Treasury bond  
4                   yields and inflation rates since 1960. Dr. Bernanke notes that the inflation  
5                   rate, at least partly, explains the pattern of interest rates. In his blog, Dr.  
6                   Bernanke also answered the “confused criticism” that “the Fed is somehow  
7                   distorting financial markets and investment decisions by keeping interest  
8                   rates ‘artificially low.’” Dr. Bernanke explains:

9                   The best strategy for the Fed I can think of is to set  
10                  rates at a level consistent with the healthy operation  
11                  of the economy over the medium term, that is, at the  
12                  (today, low) equilibrium rate. ***There is absolutely***  
13                  ***nothing artificial about that!*** (Emphasis added.)

14                  In writing in the Financial Times on August 23, 2015, Dr. Summers  
15                  explained that the state of the global economy dictates that, if we are to  
16                  achieve satisfactory economic growth, historically low interest rates are now  
17                  and will be required for quite some time, noting that long term bond markets  
18                  are telling us that real interest rates are expected to be close to zero in the  
19                  industrialized world over the next decade. Dr. Summers said:

20                  Much more plausible is the view that, for reasons  
21                  rooted in technological and demographic change and  
22                  reinforced by greater regulation of the financial  
23                  sector, the global economy has difficulty generating  
24                  demand for all that can be produced. This is the  
25                  “secular stagnation” diagnosis, or the very similar  
26                  idea that Ben Bernanke, former Fed chairman, has  
27                  urged of a “savings glut”. Satisfactory growth, if it can  
28                  be achieved, requires very low interest rates that  
29                  historically we have only seen during economic

1                   crises. ***This is why long term bond markets are***  
2                   ***telling us that real interest rates are expected to***  
3                   ***be close to zero in the industrialized world over***  
4                   ***the next decade.*** (Emphasis added.)

5                   Also, in his August 25, 2015 New York Times opinion column, Dr. Krugman  
6                   pointed to the evidence over the last seven years that demonstrates that  
7                   the low interest rates we have been experiencing are not unnatural or  
8                   artificial.

9                   The underlying claim in all such demands is that the  
10                  low interest rates we've had since 2008 are  
11                  ***“unnatural”*** or ***“artificial”***. So it's probably worth  
12                  repeating that while very low rates may seem strange,  
13                  they also seem fully justified by the economic  
14                  situation. The original Wicksellian concept of the  
15                  natural rate of interest defined that rate as the rate  
16                  consistent with stable prices, with an economy that  
17                  was neither too hot nor too cold. ***If we had had an***  
18                  ***unnaturally low rate these past 7 years, we should***  
19                  ***have seen accelerating inflation; we haven't.***  
20                  (Emphasis added.)

21                  These prominent economists are saying that our economy, due to both  
22                  domestic and international influences, has not been capable of sustaining  
23                  substantially higher interest rate levels over the past several years, and  
24                  this circumstance is not expected to change significantly anytime soon.

25                  **Q. Do you agree with Mr. Gaske's application of a “risk premium” in his**  
26                  **DCF calculation?**

27                  A. No. Mr. Gaske's claim that MDU's electric operations have a higher  
28                  risk than other electric utilities because of the percentage of coal  
29                  generation, is a poor assumption. Utility risk is based upon a variety of

1 functions, including stability of rate base, regulatory environment, debt to  
2 equity ratio, ability to meet interest payments, growth forecasts, etc. With  
3 the change in federal administration at the US Environmental Protection  
4 Agency (EPA) it is likely that the concerns due to recent pollution  
5 regulations will be minimal, including those associated with the Clean  
6 Power Plan (“CPP”). The new EPA Administrator Scott Pruitt has targeted  
7 the repeal or significant overhaul of the CPP. This change in EPA position  
8 on the CPP significantly reduces the potential for MDU to have to make  
9 costly improvements or shutdown coal generation.

10 North Dakota’s regulatory practice which allows utilities to implement  
11 interim rates while requested rate increases proceed through the  
12 regulatory process, also reduces MDU’s risk in relation to many of the  
13 utilities within the Value Line group. Not all states have a policy which  
14 allow interim rates to be implemented, resulting in significant delays  
15 between utilities incurring costs and being able to recover those costs  
16 through rate increases. North Dakota’s interim rate practice provides MDU  
17 quicker recovery of increased costs, reducing the risk of losses. MDU also  
18 enjoys the benefits of a monthly direct pass through of fuel and purchased  
19 power costs as well as a number of riders that are adjusted annually to  
20 reflect the most current costs which also reduce the Company’s risks. In  
21 addition, MDU is part of the MISO Regional Transmission Organization  
22 which helps to mitigate price risk of generation resources. Last, investors

1 will price higher risk into the price of a stock. If a utility has a higher risk,  
2 that risk would be reflected in lower stock prices and is already reflected in  
3 the information contained in the Value Line data. This will factor risk into  
4 the DCF analysis.

5 **Q. Do you feel Mr. Gaske's selection of representative utilities to be**  
6 **suitable for MDU's DCF calculation of cost of equity, is appropriate?**

7 A. No. Mr. Gaske actually provides the reason not to use his very limited  
8 selection of representative utilities in his DCF calculation. As Mr. Gaske  
9 notes, electric utility is a division of MDU Resources and investors will  
10 treat equity as part of the whole company, not just the electric utility.  
11 Investors valuations are typically focused on the earnings and dividends of  
12 the whole company. Impact of a segment of a company only partially  
13 affects the valuation and investors' decisions.

14 **Q. What was the criteria and selection process for your proxy utility**  
15 **group?**

16 A. I selected a national electric utility proxy group using the following criteria:

17 (1) Companies that are included in the Value Line electric  
18 utility industry universe;

19 (2) Electric utilities that have an S&P corporate credit rating  
20 ("CCR") of BBB to A- [This rating range encompasses one  
21 credit rating notch above and below MDU Resources' S&P  
22 rating of BBB+. MDU is a division of MDU Resources and  
23 does not have S&P and Moody's ratings of its own, and  
24 MDU Resources does not have Moody's credit ratings.];

1 (3) Electric utilities having an IBES published analysts'  
2 consensus "five-year" earnings per share growth rate;

3 (4) Electric utilities that are not engaged in major merger or  
4 acquisition ("M&A") activity currently or during the six-  
5 month dividend yield analysis period;

6 (5) Electric utilities that paid dividends throughout the six-  
7 month dividend yield analysis period, did not cut dividends  
8 during that period, and have not subsequently announced  
9 a dividend cut; and

10 (6) Electric utilities whose DCF results pass threshold tests of  
11 economic logic and are not outliers.

12 Using the three-notch S&P credit ratings screen listed in item 2 above  
13 results in selection of utilities independently judged to have comparable  
14 risks to MDU. Using this criterion based on MDU's Standard & Poor's  
15 Corporate Credit Rating of BBB+, 29 of the companies included in the Value  
16 Line electric utility universe have been included in the representative proxy  
17 group of utilities. (Exhibit PSC-4)

18 **Q. How did you apply the two-step DCF method to your proxy group of**  
19 **electric utilities?**

20 **A.** First a single six-month average dividend yield was developed for each  
21 proxy company for the six-month period ending January 2017. I then  
22 calculated a single average growth rate for each proxy group company  
23 using a "short-term" analysts' forecasted "five-year" earnings per share  
24 growth rate weighted at two-thirds, and a "long-term" forecasted GDP  
25 growth rate with a one-third weighting. For the short-term growth rate, I  
26 used the average of the analysts' consensus "five-year" earnings per

1 share growth rate projections for each proxy group company as reported  
2 by Yahoo! Finance from the Thomson Reuters/IBES database on January  
3 31, 2017. The long-term growth rate incorporated in my analysis is  
4 4.35%. This growth rate is based on forecasted long-term GDP growth as  
5 prescribed by the FERC. The calculation of this recent long-term GDP  
6 growth rate was presented by FERC Staff witness Robert J. Keyton, in  
7 recent testimony, and the source documents are included in his  
8 workpapers available from the FERC's eLibrary on the Internet. The  
9 calculations of the dividend yield and composite average growth rates are  
10 shown in Exhibit PSC-4.

11 **Q. What was the result of your DCF Analysis?**

12 A. The resulting two-step DCF analysis of proxy utilities yielded a ROE range  
13 of 5.49% to 9.94%. The median and recommended ROE for MDU came in  
14 at 8.53%. This is after removing the one outlier, Entergy Corporation  
15 because the company's growth rate is projected to be negative and the  
16 resulting ROE is well below that of all the other proxy utilities.

17 **Q. What is your recommendation for the ROE to be used in calculating**  
18 **MDU's overall rate of return?**

19 A. Based upon the two-stage DCF model and the projected 2017 capital  
20 structure for MDU of 51.4% common equity, I recommend the  
21 Commission approve a ROE of 8.53% for MDU. As discussed earlier,

1 MDU's level of risk is minor in comparison to other utilities due to the  
 2 regulatory environment in which it operates and its service area.

3 **Q. What overall rate of return are you recommending for MDU?**

4 **A.** Based upon the projected 2017 capital structure derived from MDU's  
 5 2016-year end actuals, the overall rate of return calculates to be 6.789%  
 6 as shown in the following Table 1.

7 **Table 1: MDU North Dakota Utility Operations Overall Rate of Return**

Capital Type	2017 Projected	Percent	Cost	Overall Rate of Return
Long Term Debt	\$600,440,903	42.673%	5.245%	2.238%
Short Term Debt	68,096,270	4.840%	2.402%	0.116%
Preferred Stock	15,258,600	1.084%	4.579%	0.050%
Common Equity	723,295,087	51.403%	8.530%	4.385%
<b>Total</b>	<b>\$1,407,090,860</b>	<b>100.000%</b>		<b>6.789%</b>

8

9 **Decommissioning Expense**

10 **Q. What decommissioning expenses has MDU proposed to recover**  
 11 **through electric rates in this proceeding?**

12 **A.** MDU has proposed to collect through its depreciation operating expense,  
 13 the **PROJECTED** future decommissioning expense for each of its  
 14 generation assets. It appears from Discovery Response No. 1.30 that  
 15 MDU proposes to include in rates \$1,900,146 of decommissioning  
 16 expense.

1 **Q. How has MDU proposed to account for the decommissioning funds?**

2 A. MDU has not proposed an appropriate method for accounting and capture  
3 of this expense. In response to Discovery Question 5.10, MDU proposes  
4 to establish an accrual account for tracking collection of decommissioning  
5 funds. The funds will not be held in a separate account, but used at MDU's  
6 discretion. MDU does not intend to credit the prefunded decommissioning  
7 account for interest on the funds it is using for operations. Nor does there  
8 appear to be any adjustment to the funds need for operating expenses to  
9 account for use of decommissioning funds being used for operations.

10 Unless MDU intends to create a liability account associated with the  
11 decommissioning funds, the decommissioning funds collected will become  
12 part of net company earnings. Under this arrangement, if MDU were to  
13 enter bankruptcy, the decommissioning funds would disappear. This  
14 arrangement provides North Dakota MDU ratepayers little to negative  
15 value.

16 **Q. Why is there little to no value to North Dakota ratepayers in the  
17 collection of decommissioning funds as proposed by MDU'?**

18 A. Under MDU's proposed arrangements for accrual of decommissioning  
19 funds, North Dakota ratepayers would effectively be providing MDU a loan  
20 on future expenses without being paid any interest. This funding is in  
21 today's dollars for a future expense. Today's dollars have a higher value  
22 than future dollars due to inflation. What happens to the decommissioning

1 funds if decommissioning costs are lower than projected, the plant  
2 remains in service longer, or the plant is sold? If only the accumulated  
3 dollars are returned to ratepayers without interest or accounting for time  
4 value of money, ratepayers will be refunded less than what they paid. This  
5 situation has already occurred in Montana where MDU had been  
6 collecting decommissioning funds from its Montana ratepayers. MDU had  
7 been collecting decommissioning funds for several decades in Montana  
8 with no accrued interest. On December 31, 2014, the decommissioning  
9 fund was significantly overfunded by \$6,712,194. MDU proposed to refund  
10 its customers by decreasing the depreciation expense by \$671,219  
11 annually *over a ten-year period*. Assuming the \$6.71 million over collection  
12 occurred in equal annual amounts over the 20-year basis, adjusting each  
13 collected years and refunded years' dollar to 2016-dollar value (year in  
14 which MDU began decrease in depreciation), Exhibit PSC-6 shows that  
15 MDU ratepayers will have received \$2,013,738 less than they contributed  
16 in real dollars. That represents 23% in lost value to ratepayers and a gain  
17 for MDU. Under MDU's proposed method of accounting for  
18 decommissioning funds collected in this proceeding, this is likely to occur  
19 to North Dakota ratepayers if the Commission adopts MDU's request for  
20 collection of decommissioning funds.

1 **Q. What has been the past experience in North Dakota with MDU's**  
2 **estimation of retirement costs?**

3 A. Discovery Response 5.11 shows the decommissioning costs and revenue  
4 recovery from North Dakota ratepayers for several retired power plants  
5 prior to 2001. This discovery response shows that MDU received  
6 \$331,456 more in decommissioning funding from North Dakota ratepayers  
7 than it incurred in decommissioning costs, an over collection of almost  
8 13%. These examples of the over recovery of decommissioning costs  
9 likely contributed to additional MDU profits.

10 **Q. Are there other examples of decommissioning funding?**

11 Yes. When utilities have been allowed to collect decommissioning costs  
12 for nuclear power plants, they are often required to set aside the funds in  
13 separate account which accumulates interest. This interest is then used to  
14 offset some of the decommissioning costs. Decommissioning expense  
15 needs to be tracked and periodically reviewed to see if the level of funding  
16 is appropriate.

17 **Q. What other reasons do you have for the Commission to reject MDU's**  
18 **proposal to collect future decommissioning funds?**

19 The projections for the cost of decommissioning existing generation plants  
20 contain many, many assumptions regarding retirement timing, cost of  
21 retirement, disposition of equipment, salvage value, inflation rates, etc.  
22 These assumptions can have a wide range of impacts on

1 decommissioning costs. For example, the assumed life of the new Lewis &  
2 Clark RICE Project is 40 years but this type of generation has often been  
3 in operation for much longer periods and can easily be refurbished.

4 **Q. What action should the Commission take in this proceeding**  
5 **regarding MDU's request to include decommissioning expense in its**  
6 **revenue requirement?**

7 A. I recommend the Commission reject MDU's request to include  
8 decommissioning expense associated with projected future generation  
9 asset retirement. The complications of accounting treatment, assumptions  
10 used to determine the level of decommissioning expense, tracking of  
11 funds, interest on decommissioning funds, future reconciliation process  
12 and other issues have not been adequately addressed by MDU in its  
13 testimony. MDU's past history of estimation of decommissioning costs  
14 and methods of ratepayer funding have resulted in over recover by MDU  
15 and ratepayers incurring higher rates than should have occurred.

## 16 **Other Adjustments to Electric Rate Base**

17 **Q. Do you recommend any other adjustments to MDU's electric rate**  
18 **base?**

19 A. Yes. MDU has requested to recover the loss on sale of manufactured  
20 housing it purchased to house employees. On pages 35 and 36 of Mr.  
21 Jacobson's testimony, the reason for the purchase and loss on the sale of

1 manufactured housing is discussed. As should have been expected, when  
2 a shortage occurs within a housing market, builders move to fill that  
3 shortage with new homes, which is what occurred in this instance. MDU  
4 should have known that the housing stock would catch up with demand  
5 and made other arrangements, such as helping its workers procure rental  
6 manufactured units. These are readily available and could have been  
7 used to provide employees housing.

8 In addition, there are several accounting issues with his cost item. If the  
9 housing was for temporary employee housing due to temporary relocation  
10 to a job site, then usual utility practice is to expense the temporary  
11 housing as an O&M expense. If it was not for temporary housing  
12 associated with temporary relocation, then the cost of the housing should  
13 have been paid for by the employee because it was for purposes of  
14 permanent residence. In either of these situations, this is not a legitimate  
15 capital investment and should have been treated as an O&M expense.  
16 Thus, these costs should have been paid through MDU's operating  
17 expense account and do not belong in rate base.

18 **Q. How should the Commission treat employee bonus and incentive**  
19 **compensation?**

20 **A.** The Commission should apply the same principals to MDU incentive  
21 compensation and bonuses as was applied in Case PU-10-124. In that  
22 proceeding, incentive compensation and bonuses were reduced by 60%. I

1 have made the adjustment in Statement K workpapers, resulting in a  
2 reduction of \$1,313,132 in labor costs. The MDU's figures in cells G37 and  
3 G38 of MDU Statement K Workpapers, K-152-153, were reduced by 60%.  
4 The resulting labor costs shown in cells G57-64 of Statement K  
5 Workpapers, K-152-153, were entered into the Income Statement  
6 spreadsheet, Labor Tab, cells F10-17.

7 **Lewis & Clark RICE Project**

8 **Q. Have you reviewed MDU Witness Alan L. Welte's testimony regarding**  
9 **Lewis & Clark Reciprocating Internal Combustion Engine (RICE)**  
10 **Project?**

11 **A.** Yes. The Lewis & Clark RICE Project is comprised of two 9.3 MW (18.6  
12 MW total capacity) Wartsilla 20V34SG units located at the existing Lewis  
13 & Clark plant, in Richland County, Montana. The RICE Project was placed  
14 in service in 2015 (commercial operation in April 2016) to mitigate  
15 reliability concerns in the Bakken Oil Field region areas of northwestern  
16 North Dakota and northeastern Montana, a problem identified in MDU's  
17 2013 Integrated Resource Plan (IRP). The 2103 IRP was finalized in  
18 September of 2013. The total project cost was \$47.19 million or  
19 \$2,537/kW.

1 **Q. What was the projected size and cost of this project in the 2013 IRP?**

2 A. The 2013 IRP projected the installation of 36.6 MW at a cost of \$34.95  
3 million or \$955/kW. The 2015 IRP included a revised reciprocating internal  
4 combustion engine ("RICE") project of 27.9 MW at a total cost of \$47.62  
5 million or \$1,707/kW.

6 **Q. What was the justification for the significantly higher project costs?**

7 A. Mr. Welte states that MDU was required to "fast track" the project because  
8 the Basin Electric transmission system in the Bakken Region was unable  
9 to support the rapidly increasing load. This created the risk of power  
10 interruptions to MDU customers in the winter of 2015-2016. The fast track  
11 project development was the result of MDU not beginning project  
12 development until May 29, 2014, over eight (8) months after publishing the  
13 2013 IRP. It is likely MDU was aware of this problem much sooner than  
14 the publishing of the 2013 IRP, since they would have had to study  
15 various options for addressing the potential power supply shortage in the  
16 2013 IRP final edition.

17 **Q. Have you compared the costs of MDU's RICE Project to similar  
18 power generation projects?**

19 A. Yes. GDS has worked on many different power generation projects over  
20 the last several years and tracked the generation costs for various types of  
21 generation. In addition, multiple utilities have published IRP's which  
22 provide cost estimates for various types of power generation systems. The

1 comparison of the costs of similar size generation projects is shown in  
2 Exhibit PSC-7. As can be seen in the table, the RICE Project was the  
3 most expensive, on \$/kW basis, of all the projects in the list. As a  
4 comparison, MDU's Heskett III, 88 MW combustion turbine project's cost  
5 was only about \$6 million higher than the RICE Project, while its  
6 generating capacity is over 4.7 times larger than the RICE Project.

7 **Q. What is the typical cost range for a power generation project of**  
8 **similar size to the Rice Project on a \$/kW basis?**

9 A. The typical cost for a reciprocating internal combustion engine ("Recip")  
10 project in the size range of Lewis & Clark would be about \$1,200/kW with  
11 an upper range of \$1,500/kW for a greenfield site. For an existing site with  
12 existing infrastructure, the cost should be closer to \$1,200/kW.

13 **Q. What about MDU's claim they had to construct the project on an**  
14 **expedited schedule?**

15 A. First, a typical construction schedule for a Recip project from initiation of  
16 engineering to commercial operation date is 24 to 30 months. The 19-  
17 month schedule for Lewis & Clark RICE was not significantly shorter. In  
18 fact, if you include the time to the commercial operation date of April 30,  
19 2016, the schedule was a 23-month schedule. If MDU had begun the  
20 preliminary engineering and procurement of major components upon  
21 identification of need in the 2013 IRP (September 2013), then MDU would

1 have had 27 months or more to complete the project prior to the winter of  
2 2015-2016.

3 Second, MDU also had the option of renting generation to get through the  
4 winter of 2015-2016. Several companies rent small packaged combustion  
5 turbine or Recip generator systems. In preparation for this testimony I  
6 obtained a quote to rent three Taurus 60 gas turbines for a total output of  
7 16.5 MW at a monthly rental rate of approximately \$404,331/month on a  
8 six-month contract. The total cost would have been \$2.426 million for  
9 rental of the units over the Winter of 2015-2016. Assuming a non-  
10 expedited cost of \$1,500/kW the RICE Project would have cost MDU  
11 \$27.9 million, a savings of \$19.3 million, more than enough to pay for  
12 rental of the combustion turbines. Even if you use MDU's 2015 projected  
13 RICE Project cost of \$1,707/kW the RICE Project would have cost \$31.75  
14 million, MDU would have saved over \$13.7 million, *including paying the*  
15 *cost of the rental units.*

1 **Q. What is your recommendation regarding incorporation of the Lewis**  
 2 **& Clark RICE Project into North Dakota rate base?**

3 A. I recommend that the Commission disallow a total of \$17 million of the  
 4 Lewis & Clark RICE Project. This disallowance is based upon an  
 5 appropriate installed cost of \$1,490 for an appropriate Recip project on an  
 6 existing power plant site and includes the rental cost for temporary  
 7 generation. The calculation off the recommended disallowance, as shown  
 8 in **Table 2**, will

**Table 2 - RICE Project Disallowance**

<b>Lewis &amp; Clark RICE Project</b>		<b>\$47,194,515</b>
Typical Small Generation Cost/kW	\$1,490	
Smart Power Proejct Size - kW	18,600	
<b>Typical Project Costs</b>	<b>\$27,714,000</b>	<b>\$27,714,000</b>
Cost of Rental Unit		<b>\$2,425,986</b>
<b>Excess Smart Power Project Cost</b>		<b>\$17,054,529</b>
<b>Round Down Disallowance</b>		<b>\$17,000,000</b>
North Dakota Allocation Factor		72.196505%
<b>North Dakota Disallowance</b>		<b>\$12,273,406</b>

9 reduce MDU's plant  
 10 in service by  
 11 \$12,273,406.  
 12 I believe this is a  
 13 reasonable  
 14 disallowance in that  
 15 it does not take into consideration the cost savings of building the project  
 16 on an existing power plant site. This disallowance has been reflected in  
 17 revised Exhibit PSC-3.

1 **Revenue Requirement Calculation**

2 **Q. Have you performed a revenue requirement calculation based upon**  
3 **your adjustments?**

4 A. Yes. Exhibit PSC-3 shows the calculation of MDU's revenue  
5 deficiency's/(sufficiency's) for Base Rates, the Renewable Rider and  
6 Transmission Cost Adjustment.

7 **Q. What test period did you use to determine the revenue requirement?**

8 A. My adjustments and calculations of the plant in service and revenue  
9 requirements were based upon year end 2016 and project 2017 supplied  
10 in Discovery Response 1.1. This represents the most recent year end  
11 costs and 2017 projections for MDU.

12 **Q. What changes did you make in MDU's Plant in Service?**

13 A. The following adjustments were made to MDU's plant in service:

- 14 1. Lewis & Clark RICE Project costs were reduced by \$12,273,406 to  
15 reflect the recommended disallowance.  
16 2. Removal of the provision for funding of future decommissioning costs.  
17 3. Removed the losses on sale of manufactured homes.

18 **Q. How did these items affect revenue requirements?**

19 A. Reduction in rate base results in lowering gross income which affects  
20 income taxes. These impacts are shown on the revised Statement I.  
21 Disallowances for the RICE Project, elimination of the decommissioning

1 funding and loss on manufactured housing affected depreciation and  
2 amortization amounts. All of these impacts are summarized in Exhibit  
3 PSC-3, which shows the recommended incremental revenue for MDU  
4 Base Rates is reduced to \$515,316.

5 **Q. Does this conclude your testimony?**

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

STATE OF NORTH DAKOTA


BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of  
MONTANA-DAKOTA UTILITIES CO.,  
A Division of MDU Resources Group, Inc.  
for authority to Increase Rates for Electric Service in North Dakota

Case No. PU-16-666

AFFIDAVIT OF  
Richard A. Polich

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.



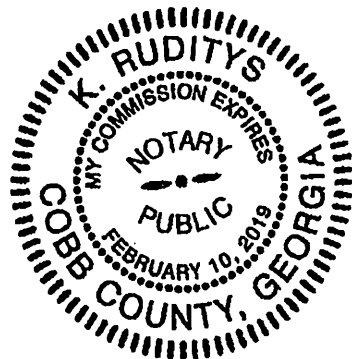
Richard A. Polich

Subscribed and sworn to before me  
this 24th day of February, 2017.



Notary Public

SEAL





Richard A. Polich, P.E.  
Managing Director – Generation Services

## EDUCATION

Master of Business Administration, University of Michigan, 1990  
Bachelor of Science, Mechanical Engineering, University of Michigan, 1979  
Bachelor of Science, Nuclear Engineering, University of Michigan, 1979

## ENGINEERING REGISTRATION

Professional Engineer in the State of Michigan

## PROFESSIONAL MEMBERSHIP

National Society of Professional Engineers  
American Nuclear Society  
American Society of Mechanical Engineers  
Association of Energy Engineers Senior Member

## PROFESSIONAL EXPERIENCE

Mr. Polich has more than 30 years' experience as an energy industry engineer, manager, and leader, combining his business and technical expertise in the management of governmental, industrial and utility projects. He has worked extensively in nuclear, coal, IGCC, natural gas, green/renewable generation. Mr. Polich has developed generation projects in wind, solar, and biomass in Australia, Canada, Caribbean, South American and United States. His generation experience includes engineering of systems and providing engineering support of plant operations. He also has extensive experience in utility rates and regulation, having managed Consumers Energy's rates group for a number of years. In that function his responsibilities included load and revenue forecasting, overseeing the design of gas and electric rates and testifying in regulatory proceedings. Mr. Polich has testified in over thirty regulatory and legislative proceedings.

Mr. Polich has testified in over 30 regulatory proceedings on a variety of issues. Recently, Mr. Polich provided direct and rebuttal testimony before the Hawaii Public Utilities Commission in Docket No. 2015-0022, regarding the Hawaiian Electric Company, Inc. and NextEra Merger. Over 15 years' experience working with Michigan Public Service Commission on renewable energy policies, independent power supplier regulations, and electric rate cases. He has also worked with the Michigan Legislature: defined laws for open markets, renewable portfolio standards. Mr. Polich has worked on various projects and policies in Arizona, Arkansas, California, Georgia, Indiana, Minnesota Nebraska, New Mexico, Ohio, Texas, and Wisconsin Commissions over the last ten years.

## SPECIFIC PROJECT EXPERIENCE

### RATES & REGULATORY

#### GDS associates, Inc. – Managing Director

SunEdison – Docket No. 2015-0022, regarding the Hawaiian Electric Company, Inc. and NextEra Merger

Presented evidence regarding NextEra's regulatory practices in Florida through its affiliate, Florida Power and Light (FPL), that indicated it would not be in the best interest for Hawai'i to approve the merger.



Richard A. Polich, P.E.  
Managing Director – Generation Services

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**North Dakota Public Service Commission Staff – Case No. PU-15-96 NSP Determination of Prudence**

Provided testimony on behalf of the North Dakota Public Service Commission Staff regarding analysis and recommendation concerning Northern States Power's ("NSP") need for additional generation resources.

**Consumers Energy - Supervisor of Pricing and Forecasting**

Managed the group responsible for setting and obtaining regulatory approval for the company's electric and gas rates. Developed new approaches to electric and natural gas competitive pricing, redesigned electric rates to simplify rates and eliminate losses and defined new strategies for customer energy pricing. Negotiated new electric supply contracts with key industrial electric customers resulting in over \$800M in annual revenue.

**EOS Energy Options & Solutions – Consulting Company**

Provided testimony for multiple clients in both Detroit Edison and Consumers Energy in over 30 regulatory proceedings. Testimony topics included rates, public policy and deregulation. Also testified in several legislative proceedings in both Michigan and Ohio, addressing energy policy. Provided expert witness testimony in Massachusetts regarding wind energy projects.

**NATURAL GAS COMBINED CYCLE EXPERIENCE**

**Consumers Energy – 1,560 MW Midland Cogeneration Venture**

Member of a small team selected to investigate the feasibility of converting the mothballed Midland Nuclear Plant into a fossil fueled power plant. Established new plant configuration that repowered the existing nuclear steam turbine with natural gas fired combustion turbines and heat recovery steam generators. Developed the new thermal cycle and heat rate, determined how to supply steam to Dow chemical for cogeneration, developed models for projecting plant performance, defined which portions of the nuclear plant were useful in the new combined cycle plant and forecasted project economics.

**Nordic Energy – (2) 1,150 MW IGCC Projects**

Project Manager for the development of two IGCC projects proposed to Georgia Power and Xcel Energy in response to RFPs. Responsibilities included establishing thermal cycles, equipment selection, site selection, supervising engineering, developing project proforma and proposals.

**Nordic Energy – 230 MW Power Barge**

This unit was to be located on the Columbia River near Portland Oregon. Lead the project development team responsible for securing equipment, designing the power plant, design of barges, assessing site feasibility, developing project economics and interconnection applications.

**Teekay Corporation – Gas to Wires Project**

Feasibility study for the development of ship mounted gas turbine power units (including combined cycle) to be fueled with LNG. Performed research into power station configuration, on-ship LNG storage, LNG fuel transfer stations and project economics.



Richard A. Polich, P.E.  
Managing Director – Generation Services

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### **RENEWABLE ENERGY EXPERIENCE**

#### **Matinee Energy – Utility Scale Solar Developer**

Engineering design and project development consultant for utility scale solar photovoltaic projects. Development activities include site selection, equipment specifications, financial analysis and preparation of proposals. Also responsible for engineering and securing electrical interconnection.

#### **Windlab Developments USA – Wind Power Developer**

Responsible for greenfield development of the US platform for wind energy projects east of the Mississippi. Developed the company's engineering protocol for wind project design and construction, responsible for managing engineering design and construction of projects, and established six wind power projects (750 MW). Responsible for negotiation of Power Purchase Agreements, electrical interconnection studies, interface with Midwest ISO and submitting Generation Interconnection Application.

#### **TradeWind Energy - Wind Power Project Developer**

Project developer for 800 MW of wind power projects in Michigan and Indiana. Introduced new project management methods to the development process which resulted in savings of over \$200,000 annually on each project.

#### **Third Planet Windpower – Wind Power Project Developer**

Engineering and project management consultant to support the startup of new wind power company. Established engineering standards used for selection of wind project equipment and project construction, analysis tools for evaluating projecting wind project power production, and performed project economic modeling.

#### **Noble Environmental Power – Wind Power Project Developer**

Electric transmission system consultant on the development of several wind power projects. Supported Noble's decisions on transmission grid interconnect and negotiate interconnection agreements.

### **ENERGY EFFICIENCY EXPERIENCE**

#### **Arkansas Energy Office – Weatherization Assistance Program Evaluation**

Evaluated the performance and operations of Arkansas's Weatherization Assistance Program. This included review of program effectiveness, program operations, energy efficiencies attained, adequacy of energy efficiency measures and subcontractor performance.

#### **CLEARResult – Arkansas Energy Efficiency Programs**

Energy efficiency operations and program support for 400% increase in Arkansas energy efficiency programs. Developed processes for data collection, field staff deployment and job assignments.



Richard A. Polich, P.E.  
Managing Director – Generation Services

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### **ECONOMIC IMPACT ASSESSMENT**

**Michigan Department of Environmental Quality - Economic Impacts of a Renewable Portfolio Standard and Energy Efficiency Program for Michigan**

Project Manager for this report which focused on the economic impact of renewable portfolio standard and energy efficiency programs on the State of Michigan. The evaluation used in this report encompassed using integrated resource planning models, econometric modeling and electric pricing models for the entire State of Michigan.

**West Michigan Business Alliance - Alternative and Renewable Energy Cluster Analysis**

Prepared the report provided a road map for Western Michigan businesses to establish new business in the renewable energy industry.

### **POWER PURCHASING AND TRADING**

**Nordic Energy LLC - Vice President**

Established an innovative energy trading floor, created customer metering and billing systems that enabled Nordic to be the first non-utility company to supply electricity to retail customers in Michigan.

### **POWER PROJECT EXPERIENCE:**

**Detroit Edison St Clair Power Station** – Performed coal combustion analysis associated with conversion Powder River Basin coal. Work included pulverizer mill performance testing, boiler combustion analysis on new coal, and unit performance analysis.

**Consumers Energy Campbell 3** - Supported start-up efforts of this 800 MW pulverized coal power plant. Part of team that performed analysis of boiler data and determined the cause of superheater failure. Also part of team to analyze performance test data for warranty evaluation.

**Consumers Energy Weadock Plant** – Design oversight and specified various plant upgrades during major maintenance outage. Included replacement of high pressure superheater, design of new steam supply pipes, valve specifications and supported plant restart.

**Consumers Energy Midland Nuclear Plant** – Responsible for overseeing EPC contractor design and construction of primary and secondary nuclear systems. Included review of systems for compliance with Nuclear Regulatory Commission regulations. Key projects included:

- Leading team to analyze plant and determine best methods for compliance with new CFR Appendix R Fire Protection rules
- Design of primary cooling system pump oil collection and disposal systems.
- Oversight of redesign of component cooling water systems.
- Analysis of diesel generator capability to meet emergency shutdown power requirements.
- Primary interface with Dow Chemical for steam supply contract.



Richard A. Polich, P.E.  
Managing Director – Generation Services

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**Consumers Energy Midland Cogeneration Venture** – Part of team to assess and develop design for converting nuclear plant to gas combined cycle project. This included researching and developing scenarios for project funding and regulatory approach Primary responsibilities included:

- Developing new thermal cycle that best utilized existing steam turbine and supply steam to Dow Chemical.
- Determining which existing assets could be utilized in new plant and determining the original construction value of these assets.

#### **REGULATORY AND LEGISLATIVE EXPERIENCE**

**Consumers Energy Manager of Rates** – Responsible for managing rate design team, forecasting annual sales and revenue forecast and developing regulatory strategies. Testified in several state and federal regulatory proceedings.

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#### **PAPERS & PUBLICATIONS**

*Engineering and Economic Evaluation of Offshore Wind Plant Performance and Cost Data, 2011, Produced for the Electric Power Research Institute, KEMA, Inc.*

*FERC's 15% Fast Track Screening Criterion, 2012, Paper reviewing the FERC 15% screening criteria for electrical interconnection, KEMA, Inc.*

*Island of Saint Maarten Sustainable Energy Study, 2012, Produced for the Cabinet of Ministry VROMI, KEMA Inc.*

*A Study of Economic Impacts from the Implementation of a Renewable Portfolio Standard and an Energy Efficiency Program in Michigan, 2007, Produced for the Michigan Department of Environmental Quality*

*Alternative and Renewable Energy Cluster Analysis, 2007, Produced for the West Michigan Strategic Alliance and The Right Place*

#### **COURSES & SEMINARS**

Association of Energy Engineers – Certified Energy Manager  
Green Building Council – Associated LEED Certification Training  
CLEAResult Leadership Academy

#### **COMMUNITY SERVICE AND ACTIVITIES**

Bicycling, hiking and cross-country skiing  
Instrument-Rated Private Pilot  
Habitat for Humanity  
Scoutmaster  
Soccer coach and referee  
Volunteer work for disaster relief and building homes in Mexico

Docket No. PU-16-666  
 Witness: Richard A Polich  
 Date: February 24, 2017  
 Exhibit No.: PSC-2  
 Page: 1 of 1

**PREVIOUS TESTIMONY OF RICHARD A. POLICH**

<b>CASE</b>	<b>ON BEHALF</b>	<b>TITLE</b>
2015-0022	Sun Edison	Regarding the Hawaiian Electric Company, Inc. and NextEra Merger
PU-15-96	ND PSC Staff	Northern States Power Determination of Prudence
U-10143	Consumers Energy	Consumers Energy Approval of an Experimental Retail Wheeling Case
U-10335	Consumers Energy	General Rate Case
U-10625	Consumers Energy	Proposal for Market-Based Rates Under Rate-K
U-10685	Consumers Energy	1996 General Rate Case
U-11915	Energy Michigan	Supplier Licensing
U-11955	Energy Michigan	Consumers Energy Stranded & Implementation Cost Recovery
U-11956	Energy Michigan	Detroit Edison Stranded & Implementation Cost Recovery
U-12478	Energy Michigan	Detroit Edison Asset Securitization Case
U-12488	Energy Michigan	Consumers Energy Retail Open Access Tariff
U-12489	Energy Michigan	Detroit Edison Retail Open Access Tariffs
U-12505	Energy Michigan	Consumers Energy Asset Securitization Cases
U-12639	Energy Michigan	Stranded Cost Methodology Case
U-13380	Energy Michigan	Consumers Energy 2000, 2001 & 2002 Stranded Cost Case
U-13350	Energy Michigan	Detroit Edison 2000 & 2001 Stranded Cost Case
U-13715	Energy Michigan	Consumers Energy Securitization of Qualified Costs
U-13720	Energy Michigan	Consumers Energy 2002 Stranded Costs
U-13808	Energy Michigan	Detroit Edison General Rate Case
U-13808-R	Energy Michigan	Detroit Edison 2004 Stranded Cost &
U-14474	Energy Michigan	Detroit Edison 2004 PSCR Reconciliation Case
U-13933	Energy Michigan	Detroit Edison Low-Income Energy Assistance Credit for Residential Electric Customers
U-13917-R	Energy Michigan	Consumers Energy 2004 PSCR Reconciliation Case
U-13989	Energy Michigan	Consumers Energy Request for Special Contract Approval
U-14098	Energy Michigan	Consumers Energy 2003 Stranded Costs
U-14148	Energy Michigan	Consumers Energy MCL 460.10d(4) Case
U-14347	Energy Michigan	Consumers Energy General Rate Case
U-14274-R	Energy Michigan	Consumers Energy 2005 PSCR Reconciliation Case
U-14275-R	Energy Michigan	Detroit Edison Company 2005 PSCR Reconciliation Case
U-14399	Energy Michigan	Detroit Edison Company Application for Unbundling of Rate
U-14992	Energy Michigan	Power Purchase Agreement and for Other Relief in Connection with the sale of the Palisades Nuclear Power Plant and Other Assets

Case No.: PU-16-666  
 Witness: RA Polich  
 Date: 24-Feb-17  
 Exhibit No. PSC - 3  
 Page: 1 of 3

**MONTANA-DAKOTA UTILITIES CO  
 PROJECTED OPERATING INCOME AND RATE OF RETURN  
 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017**

	Before Additional Revenue Requirements	<b>Additional Revenue Requirements</b>	Reflecting Additional Revenue Requirements
<b>Operating Revenues</b>			
Sales	\$182,637,355	<b>\$515,316</b>	\$183,152,671
Sales for Resale	-		-
Other	3,671,067		3,671,067
Total Revenues	<u>186,308,422</u>	<u>515,316</u>	<u>186,823,738</u>
<b>Operating Expenses</b>			
Operation and Maintenance			
Cost of Fuel & Purchased Power	54,190,975		54,190,975
Other O&M	52,325,778		52,325,778
Total O&M	<u>106,516,753</u>		<u>106,516,753</u>
Depreciation	24,745,704		24,745,704
Taxes Other Than Income	6,391,931		6,391,931
Current Income Taxes	13,656,204	194,797 1/	13,851,001
Deferred Income Taxes	0		0
Total Expenses	<u>151,310,592</u>	<u>194,797</u>	<u>151,505,389</u>
Operating Income	<u>\$34,997,830</u>	<u>\$320,519</u>	<u>\$35,318,349</u>
Rate Base	<u>\$520,229,030</u>		<u>\$520,229,030</u>
<b>Rate of Return</b>	<u><b>6.727%</b></u>		<u><b>6.789%</b></u>
Return on Equity			<u><b>8.531%</b></u>

1/ Reflects state and federal taxes at 37.8015%.

Case No.: PU-16-666  
 Witness: RA Polich  
 Date: 24-Feb-17  
 Exhibit No. PSC - 3  
 Page: 2 of 3

**MONTANA-DAKOTA UTILITIES CO  
 PROJECTED OPERATING INCOME AND RATE OF RETURN  
 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017**

**WIND - RENEWABLE RIDER**

	Before Additional Revenue Requirements 1/	Additional Revenue Requirements	Reflecting Additional Revenue Requirements
<b>Operating Revenues</b>			
Sales	\$13,923,093	(\$1,775,588)	\$12,147,505
<b>Operating Expenses</b>			
Operation and Maintenance			
Cost of Fuel & Purchased Power	0		0
Other O&M	2,102,989		2,102,989
Total O&M	2,102,989		2,102,989
Depreciation	9,231,971		9,231,971
Taxes Other Than Income	634,247		634,247
Current Income Taxes	(9,906,094)	(671,199) 2/	(10,577,293)
Deferred Income Taxes	0		0
Total Expenses	2,063,113	(671,199)	1,391,914
Operating Income	\$11,859,980	(\$1,104,389)	\$10,755,591
Rate Base	\$158,426,734		\$158,426,734
<b>Rate of Return</b>			
	7.486%		6.789%

1/ Reflects state and federal taxes at 37.8015%.

Case No.: PU-16-666  
 Witness: RA Polich  
 Date: 24-Feb-17  
 Exhibit No. PSC - 3  
 Page: 3 of 3

**MONTANA-DAKOTA UTILITIES CO  
 PROJECTED OPERATING INCOME AND RATE OF RETURN  
 REFLECTING ADDITIONAL REVENUE REQUIREMENTS  
 ELECTRIC UTILITY - NORTH DAKOTA  
 PROJECTED 2017**

**TRANSMISSION COST ADJUSTMENT**

	Before Additional Revenue Requirements 1/	<b>Additional Revenue Requirements</b>	Reflecting Additional Revenue Requirements
<b>Operating Revenues</b>			
Sales	\$6,183,536	<b>(\$674,367)</b>	\$5,509,169
Other	14,473,223		14,473,223
Total Revenues	<u>20,656,759</u>		<u>19,982,392</u>
<b>Operating Expenses</b>			
Operation and Maintenance			
Cost of Fuel & Purchased Power	0		0
Other O&M	19,982,392		19,982,392
Total O&M	<u>19,982,392</u>		<u>19,982,392</u>
Depreciation	0		0
Taxes Other Than Income	0		0
Current Income Taxes	0		0
Deferred Income Taxes	0		0
Total Expenses	<u>19,982,392</u>	<u>0</u>	<u>19,982,392</u>
Operating Income	<u>\$674,367</u>	<u>\$0</u>	<u>\$0</u>

MDU Resources Group, Inc.  
 NDPSC Case No. PU-16-666

National Electric Utility Proxy Group DCF Analysis Using Two-Step Growth DCF Methodology  
 Value Line Electrics with S&P CCR of BBB to A-  
 Using Data for the Six Months Ending January 2017

Line No.	Company (a)	Ticker (b)	Standard & Poor's Corporate Credit Rating (c)	Moody's Long Term Issuer or Sr Unsecured Rating (d)	Value Line Rank (e)	Six Month Average Dividend Yld (f)	IBES Analysts' Proj EPS g (g)	Long-term GDP Growth Rate (h)	Composite Growth Rate (i)	Adjusted Dividend Yield (j)	DCF ROE Ke (k)	Price to Book Value (l)
1	ALLETE	ALE	BBB+	A3	2	3.38%	5.00%	4.35%	4.78%	3.47%	8.25%	1.62
2	Alliant Energy	LNT	A-	Baa1	2	3.12%	6.00%	4.35%	5.45%	3.20%	8.65%	2.09
3	Amer. Elec. Power	AEP	A-	Baa1	2	3.63%	1.49%	4.35%	2.44%	3.68%	6.12%	1.80
4	Ameren Corp.	AEE	BBB+	Baa1	2	3.42%	5.85%	4.35%	5.35%	3.52%	8.87%	1.70
5	Avista Corp.	AVA	BBB	Baa1	2	3.36%	5.65%	4.35%	5.22%	3.45%	8.67%	1.60
6	Black Hills Corp.	BKH	BBB	Baa2	2	2.80%	8.39%	4.35%	7.04%	2.90%	9.94%	1.99
7	CMS Energy	CMS	BBB+	Baa2	2	2.97%	7.26%	4.35%	6.29%	3.06%	9.35%	2.78
8	Consol. Edison	ED	A-	A3	1	3.62%	2.02%	4.35%	2.80%	3.67%	6.47%	1.58
9	DTE Energy	DTE	BBB+	Baa1	2	3.29%	5.51%	4.35%	5.12%	3.37%	8.50%	1.88
10	Edison Int'l	EIX	BBB+	A3	2	2.72%	1.92%	4.35%	2.73%	2.76%	5.49%	1.96
11	El Paso Electric	EE	BBB	Baa1	2	2.70%	6.50%	4.35%	5.78%	2.78%	8.56%	1.76
12	Entergy Corp.	ETR	BBB+	Baa3	3	4.65%	-8.19%	4.35%	-4.01%	4.56%	0.55%	1.38
13	Exelon Corp.	EXC	BBB	Baa2	3	3.74%	5.95%	4.35%	5.42%	3.85%	9.26%	1.22
14	IDACORP, Inc.	IDA	BBB	Baa1	2	2.72%	4.10%	4.35%	4.18%	2.78%	6.96%	1.82
15	NorthWestern Corp.	NWE	BBB	A3	3	3.50%	4.34%	4.35%	4.34%	3.57%	7.92%	1.66
16	OGE Energy Corp.	OGE	A-	A3	2	3.70%	4.00%	4.35%	4.12%	3.77%	7.89%	1.84
17	Otter Tail Corp.	OTTR	BBB	NR	2	3.43%	6.00%	4.35%	5.45%	3.52%	8.97%	2.12
18	PG&E Corp.	PCG	BBB+	Baa1	3	3.21%	5.67%	4.35%	5.23%	3.29%	8.52%	1.74
19	Pinnacle West	PNW	A-	A3	1	3.37%	5.30%	4.35%	4.98%	3.46%	8.44%	1.78
20	PNM Resources, Inc.	PNM	BBB+	Baa3	3	2.68%	6.85%	4.35%	6.02%	2.76%	8.78%	1.45
21	Portland General	POR	BBB	A3	2	3.00%	6.60%	4.35%	5.85%	3.08%	8.93%	1.63
22	PPL Corp.	PPL	A-	Baa2	2	4.43%	2.44%	4.35%	3.08%	4.50%	7.58%	2.36
23	Public Serv. Enterprise	PEG	BBB+	Baa2	1	3.85%	1.17%	4.35%	2.23%	3.90%	6.13%	1.64
24	SCANA Corp.	SCG	BBB+	Baa3	2	3.21%	5.70%	4.35%	5.25%	3.30%	8.55%	1.80
25	Sempra Energy	SRE	BBB+	Baa1	2	2.91%	6.50%	4.35%	5.78%	2.99%	8.78%	2.10
26	Southern Co.	SO	A-	Baa2	2	4.47%	3.14%	4.35%	3.54%	4.55%	8.09%	1.75
27	Vectren Corp.	VVC	A-	NR	2	3.26%	4.57%	4.35%	4.50%	3.33%	7.83%	2.34
28	WEC Energy Group	WEC	A-	A3	1	3.36%	6.73%	4.35%	5.94%	3.46%	9.40%	2.09
29	Xcel Energy	XEL	A-	A3	1	3.33%	5.65%	4.35%	5.22%	3.42%	8.63%	1.88
30	Average				2.0	3.37%	4.56%	4.35%	4.49%	3.45%	7.93%	1.84
31	Low - 29 Companies										0.55%	
32	High - 29 Companies										9.94%	
33	Median										8.52%	
34	True 75th Percentile Value										8.78%	
35	Midpoint of the Top Half of the Array										7.59%	
	<u>After Adjustment To Remove ETR</u>											
36	Low - 28 Companies										5.49%	
37	High - 28 Companies										9.94%	
38	Median and Recommended ROE for MDU										8.53%	
39	True 75th Percentile Value										8.80%	
40	Midpoint of the Top Half of the Array										8.83%	
36	MDU Resources Group	MDU	BBB+									

Notes:

- (f) - Avg. of the monthly low and high dividend yields for the 6 months ending Jan. 31, 2017. (pp. 2-6)
- (g) - Thomson Reuters/IBES reported consensus of analysts' projected "5-year" earnings per share growth rate from Yahoo! Finance as of January 31, 2017. Xcel growth rate from Reuters.
- (h) - Average long-term GDP growth rate.
- (i) - Composite avg. growth rate with IBES and GDP growth rates weighted 2/3 and 1/3, respectively.
- (j) - Dividend yield times (1 + 0.5g), where g = composite average growth rate.
- (k) - ROE equals the adjusted dividend yield plus the composite average growth rate.
- (l) - Price to book values calculated using August 2016 - January 2017 average market price and Value Line reported year end 2016 book values. (p. 7)

Moody's Public Utility Bond Index Yields

Aug 2016 - Jan 2017	Threshold
A Bond Avg Yield:	3.94%
Baa Bond Avg Yield:	4.51%
Average	4.22%

SIX MONTH AVERAGE DIVIDEND YIELD

	Price			Div	Dividend Yield		
	High	Low	Avg		Low	High	Avg
<b>ALLETE</b>							
Jan-17	\$ 65.48	\$ 61.64	\$ 63.56	\$ 2.080	3.18%	3.37%	3.27%
Dec-16	\$ 66.92	\$ 60.97	\$ 63.94	\$ 2.080	3.11%	3.41%	3.25%
Nov-16	\$ 64.57	\$ 56.48	\$ 60.53	\$ 2.080	3.22%	3.68%	3.44%
Oct-16	\$ 61.40	\$ 56.57	\$ 58.99	\$ 2.080	3.39%	3.68%	3.53%
Sep-16	\$ 62.70	\$ 58.20	\$ 60.45	\$ 2.080	3.32%	3.57%	3.44%
Aug-16	\$ 64.46	\$ 58.60	\$ 61.53	\$ 2.080	3.23%	3.55%	3.38%
Average	\$ 64.26	\$ 58.74	\$ 61.50		3.24%	3.54%	3.38%
<b>Alliant Energy</b>							
Jan-17	\$ 38.29	\$ 36.56	\$ 37.43	\$ 1.176	3.07%	3.22%	3.14%
Dec-16	\$ 38.34	\$ 35.26	\$ 36.80	\$ 1.176	3.07%	3.34%	3.20%
Nov-16	\$ 38.67	\$ 34.88	\$ 36.77	\$ 1.176	3.04%	3.37%	3.20%
Oct-16	\$ 38.33	\$ 36.31	\$ 37.32	\$ 1.176	3.07%	3.24%	3.15%
Sep-16	\$ 40.60	\$ 37.09	\$ 38.84	\$ 1.176	2.90%	3.17%	3.03%
Aug-16	\$ 40.58	\$ 37.69	\$ 39.14	\$ 1.176	2.90%	3.12%	3.00%
Average	\$ 39.14	\$ 36.30	\$ 37.72		3.01%	3.24%	3.12%
<b>Amer. Elec. Power</b>							
Jan-17	\$ 64.11	\$ 61.82	\$ 62.97	\$ 2.360	3.68%	3.82%	3.75%
Dec-16	\$ 63.53	\$ 57.89	\$ 60.71	\$ 2.360	3.71%	4.08%	3.89%
Nov-16	\$ 64.90	\$ 58.16	\$ 61.53	\$ 2.360	3.64%	4.06%	3.84%
Oct-16	\$ 65.25	\$ 61.28	\$ 63.26	\$ 2.240	3.43%	3.66%	3.54%
Sep-16	\$ 66.96	\$ 63.56	\$ 65.26	\$ 2.240	3.35%	3.52%	3.43%
Aug-16	\$ 69.48	\$ 64.07	\$ 66.78	\$ 2.240	3.22%	3.50%	3.35%
Average	\$ 65.71	\$ 61.13	\$ 63.42		3.51%	3.77%	3.63%
<b>Ameren Corp.</b>							
Jan-17	\$ 53.40	\$ 51.35	\$ 52.38	\$ 1.760	3.30%	3.43%	3.36%
Dec-16	\$ 52.88	\$ 48.32	\$ 50.60	\$ 1.760	3.33%	3.64%	3.48%
Nov-16	\$ 51.46	\$ 46.97	\$ 49.22	\$ 1.700	3.30%	3.62%	3.45%
Oct-16	\$ 50.25	\$ 46.84	\$ 48.55	\$ 1.700	3.38%	3.63%	3.50%
Sep-16	\$ 51.91	\$ 47.79	\$ 49.85	\$ 1.700	3.27%	3.56%	3.41%
Aug-16	\$ 52.59	\$ 49.15	\$ 50.87	\$ 1.700	3.23%	3.46%	3.34%
Average	\$ 52.08	\$ 48.40	\$ 50.24		3.30%	3.56%	3.42%
<b>Avista Corp.</b>							
Jan-17	\$ 40.17	\$ 37.88	\$ 39.02	\$ 1.372	3.42%	3.62%	3.52%
Dec-16	\$ 43.00	\$ 38.69	\$ 40.84	\$ 1.372	3.19%	3.55%	3.36%
Nov-16	\$ 42.26	\$ 39.21	\$ 40.73	\$ 1.372	3.25%	3.50%	3.37%
Oct-16	\$ 41.74	\$ 38.99	\$ 40.37	\$ 1.372	3.29%	3.52%	3.40%
Sep-16	\$ 43.74	\$ 40.38	\$ 42.06	\$ 1.372	3.14%	3.40%	3.26%
Aug-16	\$ 43.71	\$ 40.30	\$ 42.00	\$ 1.372	3.14%	3.40%	3.27%
Average	\$ 42.44	\$ 39.24	\$ 40.84		3.24%	3.50%	3.36%
<b>Black Hills Corp.</b>							
Jan-17	\$ 62.70	\$ 60.02	\$ 61.36	\$ 1.680	2.68%	2.80%	2.74%
Dec-16	\$ 62.83	\$ 57.58	\$ 60.21	\$ 1.680	2.67%	2.92%	2.79%
Nov-16	\$ 61.90	\$ 54.76	\$ 58.33	\$ 1.680	2.71%	3.07%	2.88%
Oct-16	\$ 62.07	\$ 56.53	\$ 59.30	\$ 1.680	2.71%	2.97%	2.83%
Sep-16	\$ 63.79	\$ 57.51	\$ 60.65	\$ 1.680	2.63%	2.92%	2.77%
Aug-16	\$ 63.87	\$ 56.86	\$ 60.37	\$ 1.680	2.63%	2.95%	2.78%
Average	\$ 62.86	\$ 57.21	\$ 60.04		2.67%	2.94%	2.80%

**CMS Energy**

Jan-17	\$ 42.61	\$ 41.12	\$ 41.87	\$ 1.240	2.91%	3.02%	2.96%
Dec-16	\$ 42.00	\$ 39.42	\$ 40.71	\$ 1.240	2.95%	3.15%	3.05%
Nov-16	\$ 42.27	\$ 38.78	\$ 40.52	\$ 1.240	2.93%	3.20%	3.06%
Oct-16	\$ 42.55	\$ 40.01	\$ 41.28	\$ 1.240	2.91%	3.10%	3.00%
Sep-16	\$ 44.44	\$ 41.14	\$ 42.79	\$ 1.240	2.79%	3.01%	2.90%
Aug-16	\$ 45.37	\$ 41.49	\$ 43.43	\$ 1.240	2.73%	2.99%	2.86%
Average	\$ 43.21	\$ 40.33	\$ 41.77		2.87%	3.08%	2.97%

**Consol. Edison**

Jan-17	\$ 74.83	\$ 72.13	\$ 73.48	\$ 2.680	3.58%	3.72%	3.65%
Dec-16	\$ 74.30	\$ 68.85	\$ 71.58	\$ 2.680	3.61%	3.89%	3.74%
Nov-16	\$ 75.62	\$ 68.76	\$ 72.19	\$ 2.680	3.54%	3.90%	3.71%
Oct-16	\$ 76.03	\$ 71.35	\$ 73.69	\$ 2.680	3.52%	3.76%	3.64%
Sep-16	\$ 79.54	\$ 72.93	\$ 76.24	\$ 2.680	3.37%	3.67%	3.52%
Aug-16	\$ 80.61	\$ 74.09	\$ 77.35	\$ 2.680	3.32%	3.62%	3.46%
Average	\$ 76.82	\$ 71.35	\$ 74.09		3.49%	3.76%	3.62%

**DTE Energy**

Jan-17	\$ 99.49	\$ 96.58	\$ 98.04	\$ 3.300	3.32%	3.42%	3.37%
Dec-16	\$ 99.92	\$ 92.19	\$ 96.06	\$ 3.300	3.30%	3.58%	3.44%
Nov-16	\$ 96.78	\$ 89.66	\$ 93.22	\$ 3.080	3.18%	3.44%	3.30%
Oct-16	\$ 96.54	\$ 90.75	\$ 93.65	\$ 3.080	3.19%	3.39%	3.29%
Sep-16	\$ 97.60	\$ 90.61	\$ 94.10	\$ 3.080	3.16%	3.40%	3.27%
Aug-16	\$ 98.44	\$ 92.24	\$ 95.34	\$ 2.920	2.97%	3.17%	3.06%
Average	\$ 98.13	\$ 92.01	\$ 95.07		3.19%	3.40%	3.29%

**Edison Int'l**

Jan-17	\$ 72.95	\$ 70.57	\$ 71.76	\$ 2.172	2.98%	3.08%	3.03%
Dec-16	\$ 72.62	\$ 67.73	\$ 70.18	\$ 1.920	2.64%	2.83%	2.74%
Nov-16	\$ 73.44	\$ 67.44	\$ 70.44	\$ 1.920	2.61%	2.85%	2.73%
Oct-16	\$ 73.81	\$ 69.21	\$ 71.51	\$ 1.920	2.60%	2.77%	2.68%
Sep-16	\$ 76.30	\$ 71.31	\$ 73.81	\$ 1.920	2.52%	2.69%	2.60%
Aug-16	\$ 77.40	\$ 71.74	\$ 74.57	\$ 1.920	2.48%	2.68%	2.57%
Average	\$ 74.42	\$ 69.67	\$ 72.04		2.64%	2.82%	2.72%

**El Paso Electric**

Jan-17	\$ 47.20	\$ 44.70	\$ 45.95	\$ 1.240	2.63%	2.77%	2.70%
Dec-16	\$ 48.35	\$ 44.55	\$ 46.45	\$ 1.240	2.56%	2.78%	2.67%
Nov-16	\$ 47.55	\$ 43.55	\$ 45.55	\$ 1.240	2.61%	2.85%	2.72%
Oct-16	\$ 47.00	\$ 42.49	\$ 44.75	\$ 1.240	2.64%	2.92%	2.77%
Sep-16	\$ 48.75	\$ 44.07	\$ 46.41	\$ 1.240	2.54%	2.81%	2.67%
Aug-16	\$ 47.82	\$ 44.82	\$ 46.32	\$ 1.240	2.59%	2.77%	2.68%
Average	\$ 47.78	\$ 44.03	\$ 45.90		2.60%	2.82%	2.70%

**Entergy Corp.**

Jan-17	\$ 73.89	\$ 70.02	\$ 71.95	\$ 3.480	4.71%	4.97%	4.84%
Dec-16	\$ 73.79	\$ 67.84	\$ 70.81	\$ 3.480	4.72%	5.13%	4.91%
Nov-16	\$ 73.71	\$ 66.71	\$ 70.21	\$ 3.480	4.72%	5.22%	4.96%
Oct-16	\$ 76.56	\$ 70.90	\$ 73.73	\$ 3.400	4.44%	4.80%	4.61%
Sep-16	\$ 81.83	\$ 75.99	\$ 78.91	\$ 3.400	4.15%	4.47%	4.31%
Aug-16	\$ 82.00	\$ 76.60	\$ 79.30	\$ 3.400	4.15%	4.44%	4.29%
Average	\$ 76.96	\$ 71.34	\$ 74.15		4.48%	4.84%	4.65%

**Exelon Corp.**

Jan-17	\$ 36.21	\$ 34.80	\$ 35.50	\$ 1.272	3.51%	3.66%	3.58%
Dec-16	\$ 36.36	\$ 31.77	\$ 34.07	\$ 1.272	3.50%	4.00%	3.73%
Nov-16	\$ 34.06	\$ 29.82	\$ 31.94	\$ 1.272	3.73%	4.27%	3.98%
Oct-16	\$ 34.13	\$ 31.68	\$ 32.91	\$ 1.272	3.73%	4.02%	3.87%
Sep-16	\$ 35.27	\$ 32.86	\$ 34.07	\$ 1.272	3.61%	3.87%	3.73%
Aug-16	\$ 37.70	\$ 33.61	\$ 35.66	\$ 1.272	3.37%	3.78%	3.57%
Average	\$ 35.62	\$ 32.42	\$ 34.02		3.58%	3.93%	3.74%

**IDACORP, Inc.**

Jan-17	\$ 81.14	\$ 77.49	\$ 79.31	\$ 2.200	2.71%	2.84%	2.77%
Dec-16	\$ 81.81	\$ 75.03	\$ 78.42	\$ 2.200	2.69%	2.93%	2.81%
Nov-16	\$ 79.43	\$ 72.93	\$ 76.18	\$ 2.200	2.77%	3.02%	2.89%
Oct-16	\$ 78.86	\$ 73.33	\$ 76.10	\$ 2.040	2.59%	2.78%	2.68%
Sep-16	\$ 81.55	\$ 75.14	\$ 78.35	\$ 2.040	2.50%	2.71%	2.60%
Aug-16	\$ 81.71	\$ 75.46	\$ 78.58	\$ 2.040	2.50%	2.70%	2.60%
Average	\$ 80.75	\$ 74.90	\$ 77.82		2.63%	2.83%	2.72%

**NorthWestern Corp.**

Jan-17	\$ 57.88	\$ 55.99	\$ 56.94	\$ 2.000	3.46%	3.57%	3.51%
Dec-16	\$ 58.08	\$ 54.07	\$ 56.08	\$ 2.000	3.44%	3.70%	3.57%
Nov-16	\$ 59.13	\$ 54.78	\$ 56.96	\$ 2.000	3.38%	3.65%	3.51%
Oct-16	\$ 57.76	\$ 53.85	\$ 55.80	\$ 2.000	3.46%	3.71%	3.58%
Sep-16	\$ 60.71	\$ 56.18	\$ 58.44	\$ 2.000	3.29%	3.56%	3.42%
Aug-16	\$ 61.32	\$ 57.09	\$ 59.21	\$ 2.000	3.26%	3.50%	3.38%
Average	\$ 59.15	\$ 55.33	\$ 57.24		3.38%	3.62%	3.50%

**OGE Energy Corp.**

Jan-17	\$ 34.16	\$ 32.85	\$ 33.50	\$ 1.212	3.55%	3.69%	3.62%
Dec-16	\$ 34.23	\$ 31.26	\$ 32.75	\$ 1.212	3.54%	3.88%	3.70%
Nov-16	\$ 32.48	\$ 29.57	\$ 31.03	\$ 1.212	3.73%	4.10%	3.91%
Oct-16	\$ 31.69	\$ 29.61	\$ 30.65	\$ 1.212	3.82%	4.09%	3.95%
Sep-16	\$ 33.10	\$ 30.59	\$ 31.84	\$ 1.100	3.32%	3.60%	3.45%
Aug-16	\$ 32.29	\$ 29.91	\$ 31.10	\$ 1.100	3.41%	3.68%	3.54%
Average	\$ 32.99	\$ 30.63	\$ 31.81		3.56%	3.84%	3.70%

**Otter Tail Corp.**

Jan-17	\$ 40.80	\$ 37.05	\$ 38.92	\$ 1.252	3.07%	3.38%	3.22%
Dec-16	\$ 42.55	\$ 37.75	\$ 40.15	\$ 1.252	2.94%	3.32%	3.12%
Nov-16	\$ 39.75	\$ 33.45	\$ 36.60	\$ 1.252	3.15%	3.74%	3.42%
Oct-16	\$ 36.50	\$ 33.08	\$ 34.79	\$ 1.252	3.43%	3.78%	3.60%
Sep-16	\$ 36.42	\$ 33.91	\$ 35.16	\$ 1.252	3.44%	3.69%	3.56%
Aug-16	\$ 35.42	\$ 32.99	\$ 34.21	\$ 1.252	3.53%	3.80%	3.66%
Average	\$ 38.57	\$ 34.71	\$ 36.64		3.26%	3.62%	3.43%

**PG&E Corp.**

Jan-17	\$ 61.91	\$ 59.89	\$ 60.90	\$ 1.960	3.17%	3.27%	3.22%
Dec-16	\$ 61.54	\$ 57.60	\$ 59.57	\$ 1.960	3.18%	3.40%	3.29%
Nov-16	\$ 62.23	\$ 57.63	\$ 59.93	\$ 1.960	3.15%	3.40%	3.27%
Oct-16	\$ 62.69	\$ 58.20	\$ 60.45	\$ 1.960	3.13%	3.37%	3.24%
Sep-16	\$ 64.40	\$ 60.44	\$ 62.42	\$ 1.960	3.04%	3.24%	3.14%
Aug-16	\$ 65.39	\$ 61.48	\$ 63.43	\$ 1.960	3.00%	3.19%	3.09%
Average	\$ 63.03	\$ 59.21	\$ 61.12		3.11%	3.31%	3.21%

**Pinnacle West**

Jan-17	\$ 78.80	\$ 75.79	\$ 77.30	\$ 2.620	3.32%	3.46%	3.39%
Dec-16	\$ 78.97	\$ 72.61	\$ 75.79	\$ 2.620	3.32%	3.61%	3.46%
Nov-16	\$ 77.34	\$ 70.86	\$ 74.10	\$ 2.620	3.39%	3.70%	3.54%
Oct-16	\$ 76.59	\$ 72.07	\$ 74.33	\$ 2.500	3.26%	3.47%	3.36%
Sep-16	\$ 80.19	\$ 73.94	\$ 77.07	\$ 2.500	3.12%	3.38%	3.24%
Aug-16	\$ 79.54	\$ 74.28	\$ 76.91	\$ 2.500	3.14%	3.37%	3.25%
Average	\$ 78.57	\$ 73.26	\$ 75.92		3.26%	3.50%	3.37%

**PNM Resources, Inc.**

Jan-17	\$ 34.75	\$ 33.35	\$ 34.05	\$ 0.880	2.53%	2.64%	2.58%
Dec-16	\$ 34.53	\$ 31.00	\$ 32.76	\$ 0.880	2.55%	2.84%	2.69%
Nov-16	\$ 33.45	\$ 30.95	\$ 32.20	\$ 0.880	2.63%	2.84%	2.73%
Oct-16	\$ 33.25	\$ 30.98	\$ 32.12	\$ 0.880	2.65%	2.84%	2.74%
Sep-16	\$ 34.91	\$ 31.20	\$ 33.06	\$ 0.880	2.52%	2.82%	2.66%
Aug-16	\$ 34.51	\$ 31.56	\$ 33.03	\$ 0.880	2.55%	2.79%	2.66%
Average	\$ 34.23	\$ 31.51	\$ 32.87		2.57%	2.80%	2.68%

**Portland General**

Jan-17	\$ 44.15	\$ 42.61	\$ 43.38	\$ 1.280	2.90%	3.00%	2.95%
Dec-16	\$ 44.14	\$ 40.71	\$ 42.42	\$ 1.280	2.90%	3.14%	3.02%
Nov-16	\$ 43.91	\$ 40.87	\$ 42.39	\$ 1.280	2.92%	3.13%	3.02%
Oct-16	\$ 44.32	\$ 40.28	\$ 42.30	\$ 1.280	2.89%	3.18%	3.03%
Sep-16	\$ 44.12	\$ 41.71	\$ 42.91	\$ 1.280	2.90%	3.07%	2.98%
Aug-16	\$ 44.46	\$ 41.51	\$ 42.98	\$ 1.280	2.88%	3.08%	2.98%
Average	\$ 44.18	\$ 41.28	\$ 42.73		2.90%	3.10%	3.00%

**PPL Corp.**

Jan-17	\$ 34.92	\$ 33.72	\$ 34.32	\$ 1.520	4.35%	4.51%	4.43%
Dec-16	\$ 34.90	\$ 32.69	\$ 33.80	\$ 1.520	4.36%	4.65%	4.50%
Nov-16	\$ 34.98	\$ 32.46	\$ 33.72	\$ 1.520	4.35%	4.68%	4.51%
Oct-16	\$ 34.57	\$ 32.08	\$ 33.33	\$ 1.520	4.40%	4.74%	4.56%
Sep-16	\$ 35.94	\$ 33.52	\$ 34.73	\$ 1.520	4.23%	4.53%	4.38%
Aug-16	\$ 37.76	\$ 34.35	\$ 36.05	\$ 1.520	4.03%	4.43%	4.22%
Average	\$ 35.51	\$ 33.14	\$ 34.32		4.28%	4.59%	4.43%

**Public Serv. Enterprise**

Jan-17	\$ 44.70	\$ 42.86	\$ 43.78	\$ 1.640	3.67%	3.83%	3.75%
Dec-16	\$ 44.29	\$ 40.72	\$ 42.51	\$ 1.640	3.70%	4.03%	3.86%
Nov-16	\$ 43.11	\$ 39.28	\$ 41.20	\$ 1.640	3.80%	4.18%	3.98%
Oct-16	\$ 42.25	\$ 40.38	\$ 41.32	\$ 1.640	3.88%	4.06%	3.97%
Sep-16	\$ 44.01	\$ 41.07	\$ 42.54	\$ 1.640	3.73%	3.99%	3.86%
Aug-16	\$ 46.10	\$ 42.25	\$ 44.17	\$ 1.640	3.56%	3.88%	3.71%
Average	\$ 44.08	\$ 41.09	\$ 42.59		3.72%	3.99%	3.85%

**SCANA Corp.**

Jan-17	\$ 74.06	\$ 67.71	\$ 70.88	\$ 2.300	3.11%	3.40%	3.24%
Dec-16	\$ 74.99	\$ 69.71	\$ 72.35	\$ 2.300	3.07%	3.30%	3.18%
Nov-16	\$ 73.52	\$ 67.31	\$ 70.41	\$ 2.300	3.13%	3.42%	3.27%
Oct-16	\$ 73.83	\$ 67.91	\$ 70.87	\$ 2.300	3.12%	3.39%	3.25%
Sep-16	\$ 75.92	\$ 69.04	\$ 72.48	\$ 2.300	3.03%	3.33%	3.17%
Aug-16	\$ 75.80	\$ 69.83	\$ 72.82	\$ 2.300	3.03%	3.29%	3.16%
Average	\$ 74.69	\$ 68.59	\$ 71.64		3.08%	3.35%	3.21%

MDU Resources Group, Inc.  
NDPSC Case No. PU-16-666

Case No.: PU-16-666  
Witness: RA Polich  
Date: 24-Feb-17  
Exhibit No.: PSC - 4  
Page: 6 of 8

**Sempra Energy**

Jan-17	\$ 104.25	\$ 99.71	\$ 101.98	\$ 3.020	2.90%	3.03%	2.96%
Dec-16	\$ 104.70	\$ 98.12	\$ 101.41	\$ 3.020	2.88%	3.08%	2.98%
Nov-16	\$ 107.10	\$ 92.95	\$ 100.02	\$ 3.020	2.82%	3.25%	3.02%
Oct-16	\$ 109.42	\$ 101.70	\$ 105.56	\$ 3.020	2.76%	2.97%	2.86%
Sep-16	\$ 111.40	\$ 102.15	\$ 106.78	\$ 3.020	2.71%	2.96%	2.83%
Aug-16	\$ 111.96	\$ 103.62	\$ 107.79	\$ 3.020	2.70%	2.91%	2.80%
Average	\$ 108.14	\$ 99.71	\$ 103.92		2.79%	3.03%	2.91%

**Southern Co.**

Jan-17	\$ 49.85	\$ 48.19	\$ 49.02	\$ 2.240	4.49%	4.65%	4.57%
Dec-16	\$ 49.64	\$ 46.20	\$ 47.92	\$ 2.240	4.51%	4.85%	4.67%
Nov-16	\$ 51.68	\$ 46.79	\$ 49.24	\$ 2.240	4.33%	4.79%	4.55%
Oct-16	\$ 52.23	\$ 49.14	\$ 50.68	\$ 2.240	4.29%	4.56%	4.42%
Sep-16	\$ 53.73	\$ 50.77	\$ 52.25	\$ 2.240	4.17%	4.41%	4.29%
Aug-16	\$ 53.80	\$ 50.00	\$ 51.90	\$ 2.240	4.16%	4.48%	4.32%
Average	\$ 51.82	\$ 48.52	\$ 50.17		4.33%	4.62%	4.47%

**Vectren Corp.**

Jan-17	\$ 55.20	\$ 51.50	\$ 53.35	\$ 1.680	3.04%	3.26%	3.15%
Dec-16	\$ 53.05	\$ 48.41	\$ 50.73	\$ 1.680	3.17%	3.47%	3.31%
Nov-16	\$ 51.88	\$ 46.52	\$ 49.20	\$ 1.680	3.24%	3.61%	3.41%
Oct-16	\$ 50.34	\$ 47.00	\$ 48.67	\$ 1.600	3.18%	3.40%	3.29%
Sep-16	\$ 52.04	\$ 47.87	\$ 49.96	\$ 1.600	3.07%	3.34%	3.20%
Aug-16	\$ 52.47	\$ 48.56	\$ 50.52	\$ 1.600	3.05%	3.29%	3.17%
Average	\$ 52.50	\$ 48.31	\$ 50.40		3.13%	3.40%	3.26%

**WEC Energy Group**

Jan-17	\$ 59.63	\$ 57.63	\$ 58.63	\$ 1.980	3.32%	3.44%	3.38%
Dec-16	\$ 59.12	\$ 54.96	\$ 57.04	\$ 1.980	3.35%	3.60%	3.47%
Nov-16	\$ 59.74	\$ 53.66	\$ 56.70	\$ 1.980	3.31%	3.69%	3.49%
Oct-16	\$ 60.13	\$ 56.46	\$ 58.30	\$ 1.980	3.29%	3.51%	3.40%
Sep-16	\$ 63.35	\$ 59.03	\$ 61.19	\$ 1.980	3.13%	3.35%	3.24%
Aug-16	\$ 65.24	\$ 59.32	\$ 62.28	\$ 1.980	3.03%	3.34%	3.18%
Average	\$ 61.20	\$ 56.84	\$ 59.02		3.24%	3.49%	3.36%

**Xcel Energy**

Jan-17	\$ 41.43	\$ 40.04	\$ 40.74	\$ 1.360	3.28%	3.40%	3.34%
Dec-16	\$ 41.20	\$ 38.22	\$ 39.71	\$ 1.360	3.30%	3.56%	3.42%
Nov-16	\$ 41.75	\$ 38.00	\$ 39.88	\$ 1.360	3.26%	3.58%	3.41%
Oct-16	\$ 41.80	\$ 39.08	\$ 40.44	\$ 1.360	3.25%	3.48%	3.36%
Sep-16	\$ 43.49	\$ 40.34	\$ 41.92	\$ 1.360	3.13%	3.37%	3.24%
Aug-16	\$ 44.13	\$ 41.07	\$ 42.60	\$ 1.360	3.08%	3.31%	3.19%
Average	\$ 42.30	\$ 39.46	\$ 40.88		3.22%	3.45%	3.33%

Source: Yahoo! Finance

MDU Resources Group, Inc.  
NDPSC Case No. PU-16-666

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**Market Price to Book Values**

Line	Company	Ticker	Aug 2016 to Jan 2017 Avg Price	2016 Book Value	M/B
1	ALLETE	ALE	61.50	37.90	1.62
2	Alliant Energy	LNT	37.72	18.05	2.09
3	Amer. Elec. Power	AEP	63.42	35.20	1.80
4	Ameren Corp.	AEE	50.24	29.60	1.70
5	Avista Corp.	AVA	40.84	25.55	1.60
6	Black Hills Corp.	BKH	60.04	30.10	1.99
7	CMS Energy	CMS	41.77	15.05	2.78
8	Consol. Edison	ED	74.09	46.80	1.58
9	DTE Energy	DTE	95.07	50.65	1.88
10	Edison Int'l	EIX	72.04	36.70	1.96
11	El Paso Electric	EE	45.90	26.15	1.76
12	Entergy Corp.	ETR	74.15	53.75	1.38
13	Exelon Corp.	EXC	34.02	27.90	1.22
14	IDACORP, Inc.	IDA	77.82	42.65	1.82
15	NorthWestern Corp.	NWE	57.24	34.40	1.66
16	OGE Energy Corp.	OGE	31.81	17.25	1.84
17	Otter Tail Corp.	OTTR	36.64	17.30	2.12
18	PG&E Corp.	PCG	61.12	35.20	1.74
19	Pinnacle West	PNW	75.92	42.60	1.78
20	PNM Resources, Inc.	PNM	32.87	22.70	1.45
21	Portland General	POR	42.73	26.20	1.63
22	PPL Corp.	PPL	34.32	14.56	2.36
23	Public Serv. Enterprise	PEG	42.59	26.00	1.64
24	SCANA Corp.	SCG	71.64	39.80	1.80
25	Sempra Energy	SRE	103.92	49.40	2.10
26	Southern Co.	SO	50.17	28.60	1.75
27	Vectren Corp.	VVC	50.40	21.55	2.34
28	WEC Energy Group	WEC	59.02	28.20	2.09
29	Xcel Energy	XEL	40.88	21.70	1.88

Source: August 2016 to January 2017 Average price from Yahoo! Finance.  
2016 Estimated Book Values from Value Line reports dated  
December 16, 2016 and January 27 and February 17, 2017.

**MDU Resources Group, Inc.**  
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Line No.	Company	Ticker	Industry Name	Safety Rank	Long-term Issuer			Senior Unsecured			Note
					Moody's	S&P	Fitch	Moody's	S&P	Fitch	
<b>Utilities With S&amp;P CCR of BBB, BBB+, or A-</b>											
1	ALLETE	ALE	Electric Util. (Central)	2	A3	BBB+					
2	Alliant Energy	LNT	Electric Util. (Central)	2	Baa1	A-		Baa1			
3	Amer. Elec. Power	AEP	Electric Util. (Central)	2		A-	BBB	Baa1	BBB+	BBB	
4	Ameren Corp.	AEE	Electric Util. (Central)	2	Baa1	BBB+	BBB+	Baa1	BBB	BBB+	
5	Avista Corp.	AVA	Electric Utility (West)	2	Baa1	BBB					
6	Black Hills Corp.	BKH	Electric Utility (West)	2	Baa2	BBB	BBB+	Baa2	BBB	BBB+	
7	CMS Energy	CMS	Electric Util. (Central)	2		BBB+	BBB	Baa2	BBB	BBB	
8	Consol. Edison	ED	Electric Utility (East)	1	A3	A-	BBB+	A3	BBB+	BBB+	
9	DTE Energy	DTE	Electric Util. (Central)	2		BBB+	BBB+	Baa1	BBB	BBB+	
10	Edison Int'l	EIX	Electric Utility (West)	2	A3	BBB+	A-	A3	BBB	A-	
11	El Paso Electric	EE	Electric Utility (West)	2	Baa1	BBB		Baa1	BBB		
12	Entergy Corp.	ETR	Electric Util. (Central)	3	Baa3	BBB+		Baa3	BBB		
13	Exelon Corp.	EXC	Electric Utility (East)	3	Baa2	BBB	BBB	Baa2	BBB-	BBB	
14	IDACORP, Inc.	IDA	Electric Utility (West)	2	Baa1	BBB					
15	NorthWestern Corp.	NWE	Electric Utility (West)	3		BBB	BBB+	A3	BBB	A-	
16	OGE Energy Corp.	OGE	Electric Util. (Central)	2		A-	A-	A3	BBB+	A-	
17	Otter Tail Corp.	OTTR	Electric Util. (Central)	2		BBB	BBB-		BBB-	BBB-	
18	PG&E Corp.	PCG	Electric Utility (West)	3	Baa1	BBB+	A-	Baa1	BBB	A-	
19	Pinnacle West	PNW	Electric Utility (West)	1	A3	A-	A-	A3			
20	PNM Resources, Inc.	PNM	Electric Utility (West)	3	Baa3	BBB+					
21	Portland General	POR	Electric Utility (West)	2	A3	BBB					
22	PPL Corp.	PPL	Electric Utility (East)	2	Baa2	A-					
23	Public Serv. Enterprise	PEG	Electric Utility (East)	1		BBB+	BBB+	Baa2		BBB+	
24	SCANA Corp.	SCG	Electric Utility (East)	2	Baa3	BBB+	BBB-	Baa3	BBB	BBB-	
25	Sempra Energy	SRE	Electric Utility (West)	2	Baa1	BBB+	BBB+	Baa1	BBB+	BBB+	
26	Southern Co.	SO	Electric Utility (East)	2		A-	A-	Baa2	BBB+	A-	
27	Vectren Corp.	VVC	Electric Util. (Central)	2		A-					
28	WEC Energy Group	WEC	Electric Util. (Central)	1	A3	A-	BBB+	A3	BBB+	BBB+	
29	Xcel Energy	XEL	Electric Utility (West)	1	A3	A-	BBB+	A3	BBB+	BBB+	
<b>Utilities Meeting the Ratings Screens But Eliminated For Other Reasons</b>											
30	Avangrid, Inc.	AGR	Electric Utility (East)	2	Baa1	BBB+	BBB+			BBB+	Foreign control & other
31	CenterPoint Energy	CNP	Electric Util. (Central)	3	Baa1	A-	BBB	Baa1	BBB+	BBB	M&A activity
32	Dominion Resources	D	Electric Utility (East)	2		BBB+	BBB+	Baa2	BBB	BBB+	M&A activity
33	Duke Energy	DUK	Electric Utility (East)	2	Baa1	A-	BBB+	Baa1	BBB+	BBB+	M&A activity
34	G't Plains Energy	GXP	Electric Util. (Central)	3		BBB+		Baa2	BBB		M&A activity
35	NextEra Energy	NEE	Electric Utility (East)	2	Baa1	A-	A-		BBB		M&A activity
36	Westar Energy	WR	Electric Util. (Central)	2	Baa1	BBB+					M&A activity
<b>Utilities Eliminated By the Credit Ratings Screen</b>											
37	Eversource Energy	ES	Electric Utility (East)	1	Baa1	A	BBB+	Baa1	A-	BBB+	
38	FirstEnergy Corp.	FE	Electric Utility (East)	3	Baa3	BBB-	BBB-	Baa3	BB+	BBB-	
39	Hawaiian Elec.	HE	Electric Utility (West)	2		BBB-	BBB			BBB	M&A activity
40	MGE Energy, Inc.	MGEE	Electric Util. (Central)	1							No ratings
41	MDU Resources Group	MDU				BBB+	BBB+			A-	

MONTANA-DAKOTAS UTILITIES  
 RATE INCREASE APPLIATION  
 CASE NO. PU-16-666

OVER-RECOVERY EXAMPLE OF MR. GASKE'S PROPOSED FLOTATION COST ADJUSTMENT

ASSUMPTIONS:

Amount of Equity Issued: \$ 100.00 Million  
 Life Cycle of Asset: 40 Years  
 Depreciation Method: Straight Line  
 Flotation Percent: 3.2%  
 Flotation Cost: \$ 3.20 Million  
 Return on Equity 8.00%  
 Recovered Flotation Costs \$ 5.25 Million  
 Percent over Recovery 64.0%

Year	Common Equity	Depreciation Reserve	Return on Equity	Return on Equity with Flotation	Flotation Cost Recovery	Total Flotation Cost Recovered
1	\$ 100.00	0	\$ 8.00	8.256	\$ 0.26	\$ 0.26
2	\$ 97.50	\$ 2.50	\$ 7.80	8.0496	\$ 0.25	\$ 0.51
3	\$ 95.00	\$ 2.50	\$ 7.60	7.8432	\$ 0.24	\$ 0.75
4	\$ 92.50	\$ 2.50	\$ 7.40	7.6368	\$ 0.24	\$ 0.99
5	\$ 90.00	\$ 2.50	\$ 7.20	7.4304	\$ 0.23	\$ 1.22
6	\$ 87.50	\$ 2.50	\$ 7.00	7.224	\$ 0.22	\$ 1.44
7	\$ 85.00	\$ 2.50	\$ 6.80	7.0176	\$ 0.22	\$ 1.66
8	\$ 82.50	\$ 2.50	\$ 6.60	6.8112	\$ 0.21	\$ 1.87
9	\$ 80.00	\$ 2.50	\$ 6.40	6.6048	\$ 0.20	\$ 2.07
10	\$ 77.50	\$ 2.50	\$ 6.20	6.3984	\$ 0.20	\$ 2.27
11	\$ 75.00	\$ 2.50	\$ 6.00	6.192	\$ 0.19	\$ 2.46
12	\$ 72.50	\$ 2.50	\$ 5.80	5.9856	\$ 0.19	\$ 2.65
13	\$ 70.00	\$ 2.50	\$ 5.60	5.7792	\$ 0.18	\$ 2.83
14	\$ 67.50	\$ 2.50	\$ 5.40	5.5728	\$ 0.17	\$ 3.00
15	\$ 65.00	\$ 2.50	\$ 5.20	5.3664	\$ 0.17	\$ 3.17
16	\$ 62.50	\$ 2.50	\$ 5.00	5.16	\$ 0.16	\$ 3.33
17	\$ 60.00	\$ 2.50	\$ 4.80	4.9536	\$ 0.15	\$ 3.48
18	\$ 57.50	\$ 2.50	\$ 4.60	4.7472	\$ 0.15	\$ 3.63
19	\$ 55.00	\$ 2.50	\$ 4.40	4.5408	\$ 0.14	\$ 3.77
20	\$ 52.50	\$ 2.50	\$ 4.20	4.3344	\$ 0.13	\$ 3.90
21	\$ 50.00	\$ 2.50	\$ 4.00	4.128	\$ 0.13	\$ 4.03
22	\$ 47.50	\$ 2.50	\$ 3.80	3.9216	\$ 0.12	\$ 4.15
23	\$ 45.00	\$ 2.50	\$ 3.60	3.7152	\$ 0.12	\$ 4.27
24	\$ 42.50	\$ 2.50	\$ 3.40	3.5088	\$ 0.11	\$ 4.38
25	\$ 40.00	\$ 2.50	\$ 3.20	3.3024	\$ 0.10	\$ 4.48
26	\$ 37.50	\$ 2.50	\$ 3.00	3.096	\$ 0.10	\$ 4.58
27	\$ 35.00	\$ 2.50	\$ 2.80	2.8896	\$ 0.09	\$ 4.67
28	\$ 32.50	\$ 2.50	\$ 2.60	2.6832	\$ 0.08	\$ 4.75
29	\$ 30.00	\$ 2.50	\$ 2.40	2.4768	\$ 0.08	\$ 4.83
30	\$ 27.50	\$ 2.50	\$ 2.20	2.2704	\$ 0.07	\$ 4.90
31	\$ 25.00	\$ 2.50	\$ 2.00	2.064	\$ 0.06	\$ 4.96
32	\$ 22.50	\$ 2.50	\$ 1.80	1.8576	\$ 0.06	\$ 5.02
33	\$ 20.00	\$ 2.50	\$ 1.60	1.6512	\$ 0.05	\$ 5.07
34	\$ 17.50	\$ 2.50	\$ 1.40	1.4448	\$ 0.04	\$ 5.11
35	\$ 15.00	\$ 2.50	\$ 1.20	1.2384	\$ 0.04	\$ 5.15
36	\$ 12.50	\$ 2.50	\$ 1.00	1.032	\$ 0.03	\$ 5.18
37	\$ 10.00	\$ 2.50	\$ 0.80	0.8256	\$ 0.03	\$ 5.21
38	\$ 7.50	\$ 2.50	\$ 0.60	0.6192	\$ 0.02	\$ 5.23
39	\$ 5.00	\$ 2.50	\$ 0.40	0.4128	\$ 0.01	\$ 5.24
40	\$ 2.50	\$ 2.50	\$ 0.20	0.2064	\$ 0.01	\$ 5.25
41	\$ -	\$ 2.50	\$ -	0	\$ -	\$ 5.25
<b>TOTAL</b>			<b>\$ 164.00</b>	<b>169.248</b>	<b>\$ 5.25</b>	

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MONTANA-DAKOTAS UTILITIES  
 RATE INCREASE APPLIACTION  
 CASE NO. PU-16-666

EXAMPLE DECOMMISSIONING COST IMPACT ON MONTANA RATE PAYERS

DECOMMISSIONING FUNDS COLLECTION THROUGH 2014

DECOMMISSIONING COLLECTED				INFLATION ADJUSTMENTS		
YEAR	Collected	Cumulative	2016 Dollar Value	2016 Equivalent Collected Value	2016 Equivalent Cumulative Value	
1995	\$335,610	\$335,610	1.57	\$526,907	\$526,907	
1996	\$335,610	\$671,219	1.52	\$510,127	\$1,037,034	
1997	\$335,610	\$1,006,829	1.49	\$500,058	\$1,537,092	
1998	\$335,610	\$1,342,439	1.46	\$489,990	\$2,027,083	
1999	\$335,610	\$1,678,049	1.43	\$479,922	\$2,507,004	
2000	\$335,610	\$2,013,658	1.39	\$466,497	\$2,973,502	
2001	\$335,610	\$2,349,268	1.35	\$453,073	\$3,426,575	
2002	\$335,610	\$2,684,878	1.33	\$446,361	\$3,872,936	
2003	\$335,610	\$3,020,487	1.3	\$436,293	\$4,309,229	
2004	\$335,610	\$3,356,097	1.26	\$422,868	\$4,732,097	
2005	\$335,610	\$3,691,707	1.22	\$409,444	\$5,141,541	
2006	\$335,610	\$4,027,316	1.19	\$399,376	\$5,540,916	
2007	\$335,610	\$4,362,926	1.15	\$385,951	\$5,926,867	
2008	\$335,610	\$4,698,536	1.11	\$372,527	\$6,299,394	
2009	\$335,610	\$5,034,146	1.11	\$372,527	\$6,671,921	
2010	\$335,610	\$5,369,755	1.1	\$369,171	\$7,041,092	
2011	\$335,610	\$5,705,365	1.06	\$355,746	\$7,396,838	
2012	\$335,610	\$6,040,975	1.04	\$349,034	\$7,745,872	
2013	\$335,610	\$6,376,584	1.03	\$345,678	\$8,091,550	
2014	\$335,610	\$6,712,194	1.01	\$338,966	\$8,430,516	

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**MONTANA-DAKOTAS UTILITIES**  
**RATE INCREASE APPLIACTION**  
**CASE NO. PU-16-666**  
**EXAMPLE DECOMMISSIONING COST IMPACT ON MONTANA RATE PAYERS**

**2016 VALUE OF DECOMMISSIONING REFUNDS & NET RATE PAYER IMPACT**

	Depreciation Reduction Amount	CPI *	2016 Value of Refund
2016	\$671,219	1.000	\$671,219
2017	\$671,219	0.99	\$664,507
2018	\$671,219	0.980	\$657,795
2019	\$671,219	0.970	\$651,217
2020	\$671,219	0.960	\$644,639
2021	\$671,219	0.951	\$638,193
2022	\$671,219	0.941	\$631,746
2023	\$671,219	0.932	\$625,429
2024	\$671,219	0.922	\$619,111
2025	\$671,219	0.913	\$612,920

<b>2016 Value of Decommissioning Depreciation Reduction</b>	<b>\$6,416,777</b>
<b>2016 Value of Decommissioning Collections</b>	<b>\$8,430,516</b>
<b>Rate Payer Benefit/(Loss)</b>	<b>-\$2,013,738</b>
<b>Rate Payer Percent Loss</b>	<b>23.9%</b>

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MONTANA-DAKOTAS UTILITIES  
 RATE INCREASE APPLIACTION  
 CASE NO. PU-16-666  
 EXAMPLE DECOMMISSIONING COST IMPACT ON MONTANA RATE PAYERS

**LIST OF SIMILAR SMALL POWER PROJECT COSTS**

Power Plant	Technology	Fuel Type	Nameplate Capacity	Year in Service	Cost Info	Cost per kW	Cost Source
Lewis & Clark Smart Power Generation	Internal Combustion	Gas	18.6	2015	\$47,194,515	\$2,537	MDU Filing
Rentech Pasadena Cogeneration Project	Steam Turbine	Waste Heat	15.4	2015	\$30,000,000	\$1,948	SNL cost estimate
Roundtop	Internal Combustion	Gas	22.0	2015	\$31,500,000	\$1,432	<a href="#">regulatory filing</a>
--- CONFIDENTIAL ---	Internal Combustion	Natural Gas	99.0	2015*	\$120,912,150	\$1,221	Zachary Engineering
Fairmont Energy Station	Internal Combustion	Gas	26.0	2014	\$30,000,000	\$1,154	SNL cost estimate
--- CONFIDENTIAL ---	Combined Cycle	Natural Gas	540.0	2017*	\$602,223,122	\$1,115	GDS Associates
Central Utility CC Plant at White Oak	Combined Cycle	Gas	20.0	2014	\$22,000,000	\$1,100	SNL cost estimate
Jameson Energy Project	Gas Turbine	Gas	27.6	2014	\$26,220,000	\$950	SNL cost estimate
HP Hood Cogeneration	Gas Turbine	Gas	15.0	2015	\$14,250,000	\$950	SNL cost estimate
--- CONFIDENTIAL ---	Combustion Turbine	Natural Gas	43.5	2018*	\$40,200,000	\$924	GDS Associates
Quay County Generating Station (Tucumcari)	Gas Turbine	Oil	27.0	2013	\$19,800,000	\$733	SNL cost estimate
Haskett III Gas Turbine	Combustion Turbine	Natural Gas	88.0	2014	\$53,177,264	\$604	MDU Filing
Fredericktown Energy Center	Gas Turbine	Gas	27.6	2015	\$16,000,000	\$580	SNL cost estimate

**Notes:**

\*Projected operation date.