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

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Bismarck, ND 58501
(701) 222-7900

June 21, 2013

Ms. Kate Whitney
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
Helena, MT 59620

Re: General Gas Rate Application
Docket No. D2012.9.100

Dear Ms. Whitney:

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. herewith submits its rebuttal testimony of Mr. Michael J. Gardner, Mr. Robert C. Morman, Mr. Garret Senger, Dr. J. Stephen Gaske, Ms. Rita A. Mulkern, Mr. Earl M. Robinson, and Ms. Tamie A. Aberle.

Please acknowledge receipt by stamping or initiating the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs

Attachment
cc: J. Alke
Service List

Montana-Dakota Utilities Co.
Docket No. D2012.9.100
Service List

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

Before the Montana Public Service Commission

Docket No. D2012.9.100

Rebuttal Testimony
of
Michael J. Gardner

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

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

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

5 A. I am Executive Vice President, Utility Operations Support for
6 Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU
7 Resources Group, Inc.

8 **Q. Are you the same Michael Gardner who filed direct testimony earlier**
9 **in this proceeding?**

10 A. Yes, I am.

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

12 A. The purpose of my rebuttal testimony is to address the adjustment
13 proposed by Mr. Albert Clark on behalf of the Montana Consumer Counsel
14 that excluded the Customer Care and Billing (CC&B) customer information
15 system that was recently placed in service at Montana-Dakota. Mr.
16 Clark's sole reason for removing the cost of the CC&B system from the
17 cost of service was because we decided to delay actual utilization of the

1 CC&B system from the fourth quarter of 2012 until the first quarter of
2 2013.
3 **Q. Why did you delay actual utilization of the CC&B system until the**
4 **first quarter of 2013?**
5 A. The CC&B system was up and running in the early Fall of 2012.
6 By the end of November, the Company had already performed two dress
7 rehearsals, and other comprehensive testing. The September and
8 October reads were run using both systems to confirm accuracy of
9 conversion activities and billing functions in CC&B (this if often referred to
10 as parallel testing), although the bills that were sent out were under the old
11 system which we were replacing. For purposes of Sarbanes-Oxley
12 compliance, we would be required to document and test our processes
13 and controls under the new system to allow management to attest to the
14 effectiveness of controls as of December 31, 2012. The Company did not
15 want to risk process control failures, unforeseen problems and errors that
16 could arise with the full conversion to the new billing system in the fourth
17 quarter of 2012. Control failures and unforeseen problems could lead to
18 delay of the preparation of accurate and complete financial statements
19 and compromise the timely filing of the Company's annual Securities and
20 Exchange Commission (SEC) documents. By delaying the actual
21 utilization of the system until the first quarter of 2013, we removed the risk
22 of control failures, unforeseen errors and delays in year-end financial
23 reporting.

1 **Q. Is the CC&B system fully functioning and a service to customers**
2 **today?**
3 A. Yes, the new system was implemented early this year and bills
4 were issued beginning February 2, 2013. The core functions of the CC&B
5 system are to store relevant customer information, and based on meter
6 reads, produce accurate billing statements. Several services are now
7 available to customers with the implementation of the CC&B system and
8 these are all options customers told us that they want, as described in my
9 direct testimony summarized below.
10 • As part of the new CC&B system, Montana-Dakota also revamped the
11 consumer bill that provides more billing information, a graph showing
12 13 months of historical usage, and a quick view summary of the
13 amount due and the due date. The Company has received positive
14 feedback from customers on the new bill format.
15 • The new system facilitates additional customer interfaces through the
16 internet and allows for electronic bill presentment options. Starting in
17 late April, customers can for the first time enroll online, review their
18 account information, make payments, and sign up for electronic
19 delivery of their bills and communications.
20 • The CC&B system provided a platform to upgrade to the computer
21 aided dispatching (PCAD) system.

1 **Q. Would including the cost of the CC&B system in the Company's cost**
2 **of service in this case create any mismatch between test year**
3 **expenses and test year revenues?**
4 A. No it would not. The CC&B system is not like a new generation
5 station, or a main extension, that would likely generate additional
6 revenues for the Company. It is simply a necessary part of the cost of
7 providing good service to our customers. Including the cost of the system
8 in rates in this case will not create an undeserved windfall for the
9 Company. However, excluding it from rates in this case would be a
10 purposeful and knowing understatement of the true cost of providing
11 service to our customers. It would be completely unfair to penalize
12 Montana-Dakota financially because it delayed the actual utilization of the
13 new billing system by two months because of Sarbanes-Oxley
14 compliance.
15 **Q. Does this conclude your rebuttal testimony?**
16 A. Yes, it does.

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

Before the Public Service Commission of Montana

Docket No. D2012.9.100

Rebuttal Testimony
of
Robert C. Morman

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

2 A. Yes. My name is Robert C. Morman and my business address is
3 400 North Fourth Street, Bismarck, North Dakota 58501.

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

5 A. I am the Director of Gas Supply for Montana-Dakota Utilities Co.
6 (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU
7 Resources Group, Inc. as well as Intermountain Gas Company and
8 Cascade Natural Gas Corp., subsidiaries of MDU Resources Group, Inc.

9 **Q. Are you the same Robert C. Morman who filed direct testimony**
10 **earlier in this proceeding?**

11 A. Yes, I am.

12 **Q. What is the purpose of your rebuttal testimony?**

13 A. The purpose of my rebuttal testimony is to address Mr. Clark's
14 proposal to totally exclude Montana-Dakota's investment in its Billings
15 Landfill project from rate base, despite the undisputed fact it is on-line and
16 providing a long term supply of gas to our customers.

17 The Billings Landfill project represents an $11 million dollar
18 investment by Montana-Dakota, an investment which adds to our supply

1 portfolio to serve customers throughout Montana-Dakota's service area.
2 Of the $11 million dollar investment, Montana's allocation of the
3 investment is approximately $3 million which Mr. Clark proposes to
4 completely exclude from Montana-Dakota's rate base.

5 **Q. Do you agree with Mr. Clark's recommendation?**

6 A. No, I do not, for the reasons more fully explained below. The
7 Billings Landfill will be a reliable, reasonably priced, long term source of
8 natural gas for Montana-Dakota customers.

9 **Q. Would you please describe the Billings Landfill project in more detail**
10 **than provided in your direct testimony?**

11 A. The Billings Regional Landfill is one of the largest landfills in
12 Montana. It receives close to a quarter of a million tons of garbage a year
13 from a five county area. Although it is not currently required by federal
14 and state law to control methane gas emissions, it is probably the
15 Montana landfill most likely in the future to hit the metrics which would
16 require the control of such emissions.

17 The Billings Landfill project is a joint project between Montana-
18 Dakota and the City of Billings. Montana-Dakota has installed a system of
19 wells, gathering lines, and treatment facilities which remove the gas
20 emissions from the landfill and extract the usable methane gas from the
21 gas stream for use as system supply. Landfills can generate large
22 amounts of methane gas from rotting garbage, something that can
23 become an environmental issue. It is estimated that methane gas emitted

1 from a landfill is 21 times more harmful to the environment than emissions
2 emitted after the methane is burned. Montana-Dakota has turned what
3 could become an environmental issue for the City of Billings into a source
4 of gas for the Montana-Dakota customer. It is a classic win-win situation
5 for the City of Billings and for Montana-Dakota.
6 The system utilizes a molecular gate process to convert the landfill
7 gas to pipeline quality gas that can be consumed in Montana-Dakota's
8 natural gas distribution system. Montana-Dakota drilled 63 wells in
9 phases 1 and 2 of the Billings Landfill from which methane gas that is
10 being produced from decomposing garbage, is brought to the surface and
11 transferred to the gas processing facility. The depth of these wells range
12 from a minimum of 40 feet up to 133 feet with most wells exceeding 100
13 feet in depth. A series of gathering lines ranging in size from six inch lines
14 going to the individual wells to as large as 24 inch and 30 inch pipe which
15 is considered the main trunk line that receives all of the gas from the wells
16 and delivers to the processing facility. A blower at the processing facility
17 draws a vacuum on the field wells, which draws the landfill gas to the
18 plant. As there are liquids entrained in the gas withdrawn from the landfill,
19 a separator at the inlet of the process facility removes the majority of
20 liquids prior to the gas entering the molecular gate system.
21 The landfill gas that is drawn from the wells contains approximately
22 50 percent methane molecules with the remaining 50 percent consisting of
23 carbon dioxide (CO2), nitrogen, oxygen and a variety of other gases.

1 Natural gas that is delivered to Montana-Dakota's customers from
2 conventional wells and processing plants is composed of up to 95 percent
3 methane molecules. After a series of processes that 'chill' the gas to
4 remove additional liquids, the gas is then introduced to the Pressure
5 Swing Adsorption (PSA) system. The PSA separates the different sized
6 molecules of landfill gas with the intent to allow only methane molecules to
7 transfer into Montana-Dakota's distribution system for use by residential,
8 commercial and industrial customers. The goal of the processing facility is
9 to clean the gas to a point where more than 95 percent of the molecules
10 are methane. The undesirable gas is sent to a thermal oxidizer and
11 burned to reduce the amount of emissions entering the atmosphere.
12 Q. **What reasons does Mr. Clark offer for his proposal to completely**
13 **exclude the Billings Landfill facility from rate base?**
14 A. Mr. Clark proposes to completely exclude the Billings Landfill
15 project from rate base based upon an improper comparison of the first
16 year unit production costs at the Billings Landfill compared to current
17 period open market purchases. In other words, he is improperly
18 comparing the first year costs of a long term asset to current period
19 commodity costs. Moreover, his comparison ignores the fact that open
20 market purchases would have to be transported from the field to the City
21 of Billings over the WBI Energy or Northwestern pipeline, while gas from
22 the Billings Landfill project goes directly into Montana-Dakota's distribution
23 system.

1 **Q. Why have you characterized his comparison as improper?**

2 A. Any attempt to compare the unit cost of gas produced from a
3 production asset like the Billings Landfill project to the commodity cost of
4 gas purchased in the field at market rates, has to utilize a life cycle
5 analysis. The Billings Landfill project is a long lived physical asset with the
6 life span of the landfill approaching or exceeding fifty years. Because utility
7 ratemaking in Montana utilizes original cost depreciated, the Company's
8 investment cost in the Billings Landfill Project declines over time until it is
9 reduced to zero. The Company's initial investment in the Billings Landfill
10 facility is being depreciated over 30 years, and its projected additional
11 investment in the project will similarly be depreciated over a 30 year time
12 frame. Once the investment cost is fully depreciated, the cost of
13 producing gas from the landfill will be reduced to operation and
14 maintenance expense. In contrast, open market purchases of natural gas
15 in the field will be at whatever price the market dictates. The twin forces of
16 supply and demand, forces which Montana-Dakota cannot control, will
17 dictate the price Montana-Dakota must pay for open market purchases.
18 Any comparison of the unit cost of gas produced from the Billings Landfill
19 to open market purchases has to be based upon a life cycle analysis in
20 which some fairly heroic assumptions have to be made about the market
21 price of gas far into the future.

22 **Q. Did Montana-Dakota conduct such an analysis as part of its decision**
23 **to participate in the Billings Landfill project?**

1 A. Yes it did, and the analysis supported the pursuit of the project with
2 the City of Billings.
3 **Q. In his testimony Mr. Clark states that the cost of gas being produced**
4 **at the Billings Landfill is 4-5 times the current market rate and that**
5 **justifies the complete elimination of the Billings Landfill project from**
6 **the rate base. Do you agree?**
7 A. I do not. From the beginning, the project was considered a long-
8 term project and was analyzed and should be reviewed as such and not
9 analyzed on the first couple of years' production and associated costs. In
10 addition, it is important to look at the conditions at the time the decision
11 was made to proceed with the project.
12 As noted in my direct testimony, Montana-Dakota worked with
13 Wenck Engineering (Wenck), established in 1985, who has experience in
14 developing landfill methane. Wenck was involved in the initial analysis of
15 the methane potential from the landfill site, as well as in the construction of
16 the facility. Wenck provides services which include landfill design and
17 construction, permitting and environmental monitoring as well as
18 development of operating plans. To date Wenck has provided services to
19 more than 20 landfill projects throughout the upper Midwest.
20 Montana-Dakota began researching gas from landfills in 2007 and
21 the Wenck studies indicated the Billings Landfill was a viable project. In
22 2008-2009, during the time frame the decision was being made to proceed
23 with the Billings Landfill project, the Henry Hub monthly index gas price

had spiked to as high as $13 during the summer of 2008. The high price of natural gas and the effects on customer bills were of concern to Montana-Dakota, as well as other utilities, and the commissions. Montana-Dakota was at the Montana Public Service Commission in mid June 2008 and informed the Commission that natural gas prices were projected to increase from $7.89 per dekatherm in January 2008 to $12.40 per dekatherm in January 2009. In addition, the Wyoming Public Service Commission held public meetings, which Montana-Dakota participated in, throughout the state to hear customer concerns regarding the high commodity cost of natural gas that appeared to be facing customers in the foreseeable future. Montana-Dakota also discussed the projected high costs of gas with the Public Service Commission of North Dakota and the Public Utilities Commission of South Dakota. While natural gas was beginning to be produced from shale fields throughout the U.S. there was concern over production costs as well as decline curves of the gas produced from these formations. Liquefied natural gas (LNG) liquefaction plants were being built in countries such as Qatar, Indonesia and Malaysia to meet the anticipated shortfall of natural gas in the United States. LNG was projected to meet up to 12 percent of the required supply and there would be competition for the LNG shipments from countries such as China and Japan.

Montana-Dakota retained the services of Wenck to determine if there was adequate landfill gas being produced to install a gas extraction

1 project. Wenck drilled and conducted flow tests on three wells in Phases
2 1 and 2 of the landfill. The results of the flow tests indicated the quantity
3 and quality of methane was adequate to move forward with a landfill to
4 gas project.
5 While the initial and current production from the landfill is lower than
6 projected the landfill will continue producing additional methane as future
7 garbage is added to the facility. In the summer of 2012 a horizontal
8 gathering pipe was installed in Phase 3 of the landfill and gas production
9 from this pipe has increased the production from the landfill by
10 approximately 65 dkt/day or an increase of 15 to 20 percent. At this time
11 Phase 4 is near a point where a horizontal pipe can be installed as the
12 level of garbage in this location provides sufficient cover to produce and
13 extract landfill gas. Using landfill projections from discussions with the
14 City of Billing it is believed that in 2014, a second horizontal collector will
15 be installed in Phase 3, an additional horizontal pipe can be installed in
16 Phase 5 in 2015 and a second pipe installed in Phase 4 in 2016.
17 Montana-Dakota is also exploring the feasibility of installing facilities to
18 draw methane gas off the current leachate disposal area, which is the
19 location at the landfill where Montana-Dakota disposes the leachate
20 received at the inlet of the plant. Montana-Dakota personnel working at
21 the landfill believe there is a significant amount of landfill methane being
22 produced in the area the leachate is being injected as this liquid promotes
23 additional methane production. Montana-Dakota is also researching the

1 possibility of injecting leachate into areas of Phases 1 and 2 in an attempt
2 to produce more methane from these areas of the landfill.
3 On the demand side there was a concern that natural gas would be
4 relied upon heavily for the generation of electricity, as potential mandatory
5 early retirement of coal fired electric plants with replacement generation
6 fueled by natural gas was being considered. There was much uncertainty
7 at this time and Montana-Dakota was presented an opportunity to meet
8 both short and long term demand needs with a facility connected to the
9 Billings distribution system. By delivering the gas directly into the
10 Montana-Dakota system, pipeline transportation charges are eliminated as
11 this gas does not transfer through a high pressure pipeline to the city gate
12 and into the Montana-Dakota distribution system.
13 **Q. Was the decision to develop the Billings Landfill a good decision?**
14 Yes. This project provides a source of long term gas supply which
15 was determined to be needed. When Montana-Dakota decided to
16 proceed with the project, the commodity cost of gas had dropped to
17 around $7 per dk but indications were the prices would escalate going
18 forward. Montana-Dakota's studies still deemed this project as being
19 competitive and the decision was made to move forward with the landfill
20 project as being in the best interest of customers.
21 During this time Montana-Dakota was evaluating the Billings
22 Landfill project and it was determined to be a viable supply of reasonably

1 priced natural gas based on the information the Company received from
2 Wenck.
3 **Q. Why is the production from the landfill less that had been projected?**
4 A. During the evaluation of the field, three wells were drilled in the
5 landfill, one well in Phase 1 and two wells in Phase 2. The flow rates from
6 the all three test wells indicated withdrawal of landfill gas that contained
7 methane content of approximately 50 percent along with the other landfill
8 components of CO2, nitrogen, oxygen, etc. This is consistent with the gas
9 components for landfill projects as stated in Environmental Protection
10 Agency (EPA) documents and the moisture content was sufficient to
11 believe production of methane was adequate for commercial production.
12 Current production from Phase 1 is approximately 65 mcf per day with
13 one-third of the production from the test well. When the additional wells
14 were drilled in Phase 1, the garbage content in certain areas contained a
15 considerable amount of construction material, which is drier than the test
16 well and does not allow for much methane production.
17 The landfill wells and associated gathering system were installed in
18 both Phase 1 and Phase 2 during the summer of 2010 and Montana-
19 Dakota commenced producing gas from the landfill in December 2010.
20 From the beginning of the methane production, the wells from the Phase 1
21 area of the landfill produced very little methane gas, Phase 2 is producing
22 gas at a rate that is close to the flow results conducted during the initial
23 testing of the landfill.

1 **Q. Have you made any changes in the development of the Billings**
2 **Landfill?**
3 A. Yes. The original plan was to drill vertical wells in Phase 3 once
4 this phase was filled with garbage, however, the City of Billings changed
5 its method of filling the landfill and is currently filling Phases 3, 4 and 5 in a
6 somewhat simultaneous manner. Each phase will receive 'lifts' of
7 approximately 20-30 feet of rubbish fill. Instead of continuing to fill Phase
8 3 to its maximum depth as in the original plan, the City is filling Phase 4 to
9 a depth of 30 feet, then plans to add an additional lift to Phase 3 while a
10 liner is being installed in Phase 5 which will then receive a lift of 30 feet.
11 The current plan is to continue adding lifts to these three phases until the
12 desired depth of fill is achieved. With this change in the method of filling
13 the landfill methane gas can be gathered and processed sooner than the
14 original plan of drilling vertical wells once each phase was filled to the
15 maximum level. It would be in excess of four years before vertical wells
16 could be drilled if the original plan of adding garbage to the landfill had
17 been followed.
18 Along with the change by the City of Billings in the operation of the
19 landfill and Montana-Dakota personnel gaining a better understanding that
20 methane was produced earlier in the life of this landfill than originally
21 indicated, the decision was made to install horizontal well piping to capture
22 the early production of methane, an inexpensive investment.

1 During the summer of 2012 Montana-Dakota installed horizontal
2 piping in Phase 3, a new area of the landfill, when enough rubbish was
3 present to bury the pipe without fear of damage to the piping. The pipe
4 was covered and withdrawal of landfill gas commenced in the fall of 2012.
5 To date the results are encouraging. As stated above, with minimum
6 coverage over the horizontal pipe, the facility has increased production by
7 approximately 15 to 20 percent. As cover is added, Montana-Dakota is
8 confident that a substantial increase in methane recovery will occur as the
9 breakdown of the garbage will produce additional volumes of methane
10 gas. As mentioned above, we are exploring the use of leachate to
11 enhance production, and will be working with the Montana Department of
12 Environmental Quality (DEQ) to obtain approval.
13 **Q. What does the future production and cost look like today?**
14 A. As noted above, Montana-Dakota personnel have learned a great
15 deal since the facility was put into service. While the amount of methane
16 gas produced in Phase I to-date has been disappointing, the production
17 withdrawn from the horizontal piping in the initial layer in Phase 3 is
18 positive.
19 By continuing the installation of horizontal piping as additional lifts
20 of garbage are filled, projections indicate that over the next 28 years, the
21 average cost of the gas from the landfill will be approximately $7.10 per
22 dekatherm of gas. When looking at future estimates of natural gas pricing,
23 the projected landfill prices, while higher than the current projected price,

1 are closer to the index prices over the long term and still at the range of
2 the estimated price at the time the decision was made. With the
3 installation of horizontal wells gas will be produced earlier than the original
4 plan. The original plan had additional wells being drilled as each phase
5 was completely filled prior to the vertical wells being drilled. The capital
6 costs to develop the facility with horizontal piping are considerably less
7 than vertical wells as Montana-Dakota is able to install the horizontal
8 piping while garbage is being added to the landfill.

9 **Q. Is the higher than market cost in the initial years indicative of future**
10 **costs?**

11 It is not uncommon for new projects to see elevated costs during
12 the initial years as startup costs and working the 'bugs' out of the process
13 take time and sometimes additional unexpected costs. It takes time to
14 work through the nuances of the equipment, proper balancing of the
15 approximate 60 wells associated with the gathering system and learning
16 and understanding of the best methods, which in the initial years resulted
17 in times when the facility was not running at maximum capacity.

18 **Q. What is your conclusion of the viability of the Billings Landfill?**

19 A. As stated above, Montana-Dakota continues to view the Billings
20 Landfill as a long term source of gas. With the knowledge gained by
21 Company personnel and the changes made by the City of Billings in
22 regard to the method of filling the landfill, Montana-Dakota believes the
23 cost of producing the pipeline quality gas will be reduced significantly from

1 the current day production costs. The O&M costs of the facility are
2 consistent with projected costs during the evaluation of the project and the
3 projected increase in the amount of gas produced by the landfill will
4 improve project economics. At the time the decision was made to move
5 forward with the project, the information Montana-Dakota had available
6 indicated that this project was a reliable, reasonably priced, long term
7 source of natural gas for Montana-Dakota customers.
8 **Q. Does that complete your rebuttal testimony?**
9 A. Yes, it does.

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

Before the Public Service Commission of Montana

Docket No. D2012.9.100

Rebuttal Testimony
of
Garret Senger

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

2 A. Yes. My name is Garret Senger and my business address is 400
3 North Fourth Street, Bismarck, North Dakota 58501.

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

5 A. I am Vice President of Regulatory Affairs and Chief Accounting
6 Officer (CAO) for Montana-Dakota Utilities Co. (Montana-Dakota), and
7 Great Plains Natural Gas Co. (Great Plains), Divisions of MDU Resources
8 Group, Inc.

9 **Q. Are you the same Garret Senger who filed direct testimony earlier in**
10 **this proceeding?**

11 A. Yes, I am.

12 **Q. What is the purpose of your rebuttal testimony?**

13 A. The purpose of my rebuttal testimony is to address Dr. Wilson's
14 adjustment to Montana-Dakota's capital structure.

15 **Q. Do you agree with the adjustment proposed by Mr. John Wilson to**
16 **the capital structure ratios in his direct testimony on pages 34**
17 **through 39?**

18 A. No, I do not agree with the adjustments made to the capital

1 structure as proposed by Mr. Wilson. In his direct testimony Mr. Wilson
2 adjusts Montana-Dakota's actual capital structure to a hypothetical capital
3 structure on the basis that the Company's equity ratio is above average
4 and above the Company's targeted 50/50 capital structure ratio.
5 The targeted capital structure of 50/50 is just that, a target, and can
6 be impacted by numerous circumstances, such as timing of debt and
7 equity issuances, cost of materials, and timing of capital improvements,
8 among others. Montana-Dakota's capital structure ratio over the last
9 couple years has been primarily affected by the federal bonus tax
10 depreciation on capital projects causing the slight increase in equity
11 versus debt. While the equity ratio increased slightly, customers benefit
12 from the federal bonus tax depreciation as it reduces rate base in the form
13 of higher accumulated deferred income taxes. Absent bonus tax
14 depreciation, Montana-Dakota's equity ratio would be lower and its rate
15 base higher. Mr. Wilson's hypothetical capital structure arbitrarily changes
16 the Company's capital structure and unfairly penalizes the Company
17 when the Company effectively managed its capital while taking advantage
18 of federal legislation to the benefit of its customers.
19 **Q. Mr. Wilson states on page 35 of his direct testimony that a 53 percent**
20 **equity ratio is above the average ratio of 49.74 percent for the**
21 **comparable gas distribution utility companies. Do you believe that**
22 **should be a concern for the Commission?**
23 A. No, I do not. In today's financial environment, maintaining a

healthy balance sheet reducing leverage is smart business sense, and a 53 percent equity ratio is not excessive. The 55.6 percent equity ratio referenced by Mr. Wilson on page 35 of his direct testimony includes preferred stock, which should not be combined with the common equity ratio, as preferred stock is more closely thought of as a debt instrument than common equity. My reference to a 50/50 ratio is a 50 percent target for common equity, and does not include preferred stock.

In summary, Mr. Wilson's hypothetical capital structure arbitrarily changes the Company's capital structure and unfairly penalizes the Company when the Company took advantage of federal bonus tax depreciation to the benefit of its customers, resulting in a capital structure with a slight increase in equity versus debt. The Company's 53 percent equity ratio does not include preferred stock and is not excessive in today's financial environment.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

DOCKET NO. D2012.9.100

PREPARED REBUTTAL TESTIMONY OF

J. STEPHEN GASKE

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

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

4 **Q2. Are you the same J. Stephen Gaske who filed Prepared Direct Testimony earlier**
5 **in this proceeding?**

6 A. Yes.

7 **Q3. What is the purpose of your Rebuttal Testimony in this proceeding?**

8 A. I am responding to the Direct Testimony concerning return on common equity filed by
9 John W. Wilson on behalf of the Montana Consumer Counsel. Dr. Wilson
10 recommends a 9.0 percent allowed return on common equity for Montana-Dakota's
11 Montana natural gas distribution operations. However, as shown in my Prepared
12 Direct Testimony, and as discussed herein, a return on common equity of 10.5 percent
13 is required in order for Montana-Dakota to be in a position to raise capital on
14 reasonable terms.

1 **Q4. Please summarize the reasons that you believe Dr. Wilson's ROE**
2 **recommendation in this proceeding is not reasonable.**
3 A. There are several sources of error in the testimony of Dr. Wilson that lead him to
4 recommend an inadequate return, including:

5 1. Failure to use realistic estimates of investors' growth rate expectations;
6 2. Use of Discounted Cash Flow ("DCF") estimates that do not provide an
7 adequate risk premium above the average yields on Baa-rated utility bonds;
8 3. Reliance on the Capital Asset Pricing Model ("CAPM"), which produces
9 unreliable and unsupportable estimates of the required rate of return;
10 4. Failure to recognize that a flotation cost adjustment is required in order to meet
11 the capital attraction standard that must be met regardless of whether the
12 regulated company has incurred flotation costs in the past, or can demonstrate
13 that it will definitely incur such costs in the near future; and,
14 5. Failure to recognize that Montana-Dakota's Montana natural gas distribution
15 operations face greater overall business and regulatory risks than the typical
16 company in the proxy group.

17 **<u>Reasonableness of ROE Recommendations</u>**

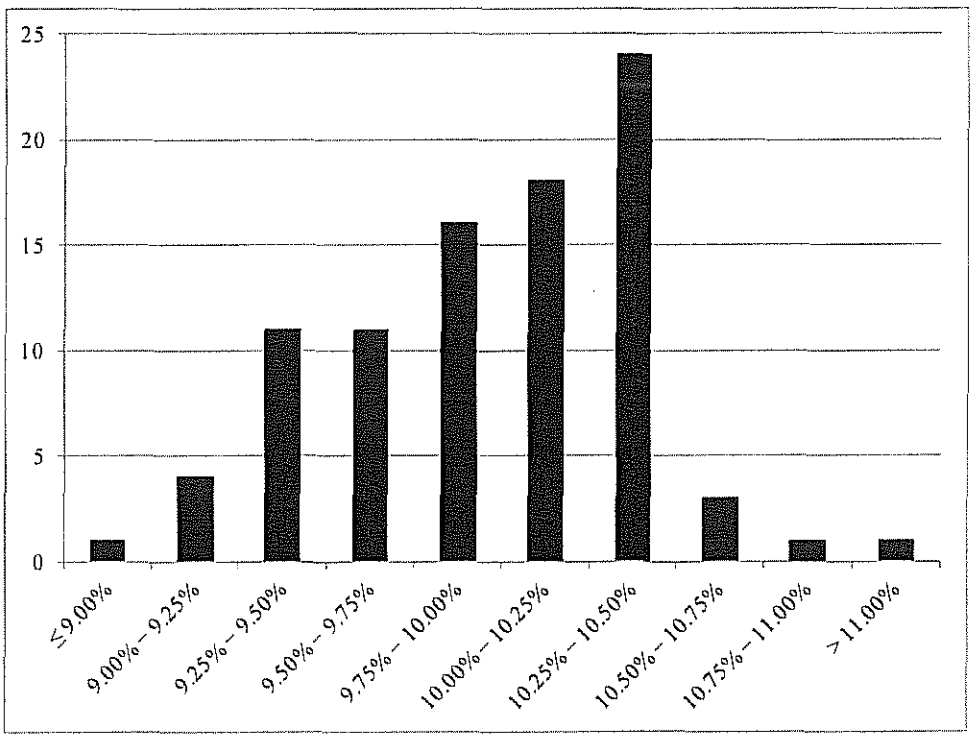
18 **Q5. Please provide an overview of Dr. Wilson's ROE recommendation in this**
19 **proceeding.**
20 A. Dr. Wilson argues for a range of return on equity between 7.0 percent and 9.0 percent
21 based on the results of his Constant Growth DCF model, fundamental DCF model,
22 CAPM analysis and Comparable Earnings analysis. In performing his DCF and CAPM
23 analyses, Dr. Wilson uses the same proxy group of eight natural gas distribution

companies that I relied on in my analysis. In applying his Constant Growth DCF analysis, Dr. Wilson uses a combination of forecasted earnings growth rates, dividend growth rates, and book value growth rates, as well as retention growth rates.

Q6. Please assess the reasonableness of Dr. Wilson's 9.0 percent recommended return on common equity.

A. Figure 1 below is a histogram of all returns on common equity authorized in natural gas distribution rate proceedings covered by Regulatory Research Associates between 2010 and 2012.

Figure 1: Authorized Returns on Equity for Natural Gas Distribution Utilities (2010-2012)[1]



[1] Source: Regulatory Research Associates

With respect to Dr. Wilson's recommended ROE of 9.0 percent, of the 90 natural gas rate proceedings with explicit ROE awards from 2010-2012, only one award was at 9.0 percent or less. By comparison, 29 of the 90 ROE awards for natural gas distribution companies (or 32 percent) were between 10.25 percent and 11.00 percent over this same time period. This evidence demonstrates that Dr. Wilson's recommendation is at the extreme low end of returns allowed by Commissions in recent years. It is evident that setting the authorized return on common equity for Montana-Dakota's Montana natural gas distribution operations at 9.0 percent would violate the comparable investment standard set forth by the United States Supreme Court in *Federal Power Commission v. Hope Natural Gas Company* (1944). The return recommendation of Dr. Wilson would not provide investors with an ROE that is "commensurate with returns on investments in other enterprises having corresponding risks."[2]

Q7. Please summarize your concerns with Dr. Wilson's analyses and recommendation.

A. The most significant flaw in Dr. Wilson's analyses is the obvious implausibility of many of his results. For example, there are several instances where Dr. Wilson estimates that the required rate of return on common equity is either equivalent to or only slightly higher than the average yield on the Moody's Baa utility bond index, despite the fact that common stocks have substantially higher risks and required returns than bonds. In addition, I disagree with Dr. Wilson in other areas of our respective analyses, including: (1) the appropriate growth rates to be used in the DCF analyses; (2) dividend yield adjustments; (3) the use of a CAPM analysis and Dr. Wilson's application of that model,

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[2] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944)

1 and (4) the appropriateness and application of a flotation cost adjustment.
2 Furthermore, Dr. Wilson and I disagree on the business risks faced by Montana-
3 Dakota's natural gas distribution operations.

4 **Comparable Companies in the Proxy Group**

5 **Q8. Do you agree with Dr. Wilson's concern that the high end of your ROE range is**
6 **based on the DCF results for South Jersey Industries?**

7 A. No, I do not. On page 14, lines 9-12 of his Direct Testimony, Dr. Wilson states that
8 the high end of my ROE range is based on the DCF results for South Jersey Industries
9 ("SJI"), which Dr. Wilson asserts "is substantially involved in non-utility businesses
10 with entirely different risks than those faced by a regulated gas distribution utility."[3]
11 According to Dr. Wilson's testimony, in 2010 and 2011 SJI derived 35 percent and 41
12 percent, respectively, of its total earnings from non-utility income from continuing
13 operations, and non-utility "economic" earnings were 46 percent and 39 percent,
14 respectively, of SJI's total economic earnings.[4]

15 As explained in my Prepared Direct Testimony, all of the companies in my proxy group
16 derived at least 70 percent of their operating income from regulated natural gas
17 distribution operations in 2011, and devoted at least 70 percent of their total assets to
18 the provision of natural gas distribution service in 2011.[5] Specifically, in 2011 SJI
19 derived approximately 84 percent of its operating income from natural gas distribution
20 operations and devoted approximately 72 percent of its assets to natural gas distribution

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[3] Direct Testimony of John W. Wilson, at 14.
[4] Direct Testimony of John W. Wilson, at 14.
[5] See Prepared Direct Testimony of J. Stephen Gaske, at 17.

service.[6] Extracts from the Business Segment section of SJI's 2011 SEC Form 10-K are shown on Exhibit No._(JSG-04), Schedule 1 attached to this testimony. Consequently, SJI passed my business segment screening criteria and is primarily engaged in natural gas distribution operations, as indicated by the percentage of operating income and assets dedicated to that business. In addition, most of SJI's non-utility businesses are closely related to natural gas distribution. For example, its non-utility businesses include such things as wholesale marketing of natural gas, gas storage and transportation services, marketing natural gas and electricity to retail end users, and installing and servicing heating and air conditioning systems for residential and small commercial customers. Consequently, I continue to believe it is appropriate to include SJI in the proxy group, and to use the DCF results for that company to establish my range of reasonable ROE results.

DCF Growth Rate Estimates

Q9. What growth rate estimates does Dr. Wilson rely on for his Constant Growth DCF analysis?

A. As shown on Exhibit Nos.___(JWW-1) through (JWW-3), Dr. Wilson relies on earnings growth rates from Value Line and Zacks, as well as dividend growth rates and book value growth rates from Value Line in his Constant Growth DCF analysis.

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[6] These percentages are based on information filed by South Jersey Industries in its 2011 SEC Form 10-K.

1 **Q10. Why do you believe that analysts' projections of earnings growth rates are a**
2 **superior measure of long-term investor expectations and therefore should be**
3 **given emphasis in any analysis used to calculate an appropriate ROE?**
4 A. Although analysts' long-term growth forecasts are typically expressed as five-year
5 forecasts, these forecasts generally represent growth rate expectations for a longer
6 period of time than the five-years expressed in the forecast. There is a large amount of
7 literature that suggests analysts' growth rate forecasts are a superior measure of the
8 long-term growth rate expectations that are reflected in stock prices. For example, the
9 research of Professors Carleton and Vander Weide demonstrates that earnings growth
10 projections have a statistically significant relationship to stock valuation levels, while
11 dividend growth projections do not.[7] Those findings suggest that investors form their
12 investment decisions based on expectations of growth in earnings, not dividends.
13 Consequently, earnings growth, not dividend growth, is the appropriate measure for the
14 purpose of the Constant Growth DCF model.

15 This indicates that analysts' estimates are an accurate estimator of long-term growth rate
16 expectations implicit in stock prices, even though the analysts' estimates are putatively
17 five-year estimates. Similarly, Marston, Harris and Crawford examined publicly
18 available data from 1982-1985 and found that "plausible measures of risk are more

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[7] Vander Weide, J.H. and Carleton, W.T., "Investor Growth Expectations: Analysts vs. History," *The Journal of Portfolio Management*, Spring 1988, pp. 78-82.

closely related to expected returns derived from a constant growth model than to those derived from multistage growth models."[8]

In 2004, the Carleton and Vander Weide study was updated to determine whether analysts' earnings growth forecasts are still significant in the stock valuation process. The results of that updated study continued to demonstrate the importance of analysts' earnings forecasts, including the application of those forecasts to utility companies.[9] Here again, the finding was clear: analysts' earnings forecasts are highly related to stock price valuations and, therefore, are appropriate inputs to stock valuation and ROE estimation models. In addition, Dr. Roger Morin cites several published studies which demonstrate that growth forecasts made by securities analysts represent an appropriate source of DCF growth rates and are reasonable indicators of investor expectations.[10]

Q11. Do you agree with Dr. Wilson's contention that analyst growth rates tend to be somewhat bullish?

A. No, I do not. On page 11, line 20 to page 12, line 3 of his Direct Testimony, Dr. Wilson states, "Analysts often publish their expectations, which, overall, tend to be somewhat bullish, but there is no published consensus value for the generally more conservative expectations investors hold."[11] The only support for this statement is Dr. Wilson's observation that stock prices are typically somewhat lower than analysts' price forecasts. Dr. Wilson provides absolutely no data or analysis in his Direct Testimony to

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[8] F. Marston, R. Harris, and P. Crawford, "Risk and Return in Equity Markets: Evidence Using Financial Analysts' Forecasts," in *Handbook of Security Analysts' Forecasting and Asset Allocation*, J. Guerard and M. Gultekin (eds.), Greenwich, CT, JAI Press; as described in R. Harris and F. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, Summer 1992, p. 64.

[9] Advanced Research Center, Investor Growth Expectations, Summer, 2004.

[10] Morin, Roger T., New Regulatory Finance, pg, 298.

[11] Direct Testimony of John W. Wilson, at 11-12.

1 support this claim. The Company subsequently requested that Dr. Wilson provide any
2 empirical data which support his assertion in data request MDU-13. Dr. Wilson's
3 response indicates that "[o]ver the past four decades Dr. Wilson has regularly compared
4 analysts' forecasts (both IBES and Value Line) with actual market data" and that "while
5 there have been exceptions from time to time, it generally has been the case that
6 analysts' published expectations (both with respect to stock market prices and earnings
7 growth) have exceeded actual market experience." However, Dr. Wilson has not
8 provided any data or analysis to support his claim.

9 Pursuant to the Global Analyst Research Settlement ("Global Settlement") announced
10 on April 28, 2003 by the Securities and Exchange Commission, New York Attorney
11 General, North American Securities Administrators Association, National Association
12 of Securities Dealers, and the New York Stock Exchange, ten of the nation's largest
13 investment firms agreed to pay fines upwards of $1.4 billion and to make structural
14 changes to separate research and investment banking. This Global Settlement
15 effectively removed the influence of investment bankers on analysts and requires
16 analysts to publish unbiased research. The ten firms, among other stipulations, agreed
17 to physically separate research and investment banking departments, prohibit the link
18 between analysts' compensation and investment banking performance, erect firewalls
19 between research and investment banking to prevent improper communication, and
20 provide independent research to their customers. It is this unbiased research that
21 investors rely on when making investment decisions.

Q12. Is there academic research that has examined the question of whether analysts' earnings forecasts are overly optimistic?

A. Yes, there are a number of studies that discuss the issue of analyst bias in growth rates and find no empirical support for the proposition that analysts' forecasts are biased and overly-optimistic. For example, a study by Ramnath *et al.* finds the I/B/E/S (now Thomson First Call) forecasts to be more accurate than Value Line, even though Value Line does not have the same potential conflicts of interest because it is neither an underwriter nor a broker. Its revenues come from a very large group of subscribers, who are both buyers and sellers of common stock. (Sundaresh Ramnath, Steve Rock, and Philip Shane, *Value Line and I/B/E/S Earnings Forecasts*, International Journal of Forecasting, Volume 21, Issue 1, 2005, at 185-198).

In a more recent study by the same authors (Ramnath *et. al*), the authors review all papers related to the role of financial analysts published since 1992 in major research journals. Based on this review of the research, the authors conclude that "analysts' forecasts effectively proxy for the market's earnings expectations."[12] On the specific topic of analyst bias, the authors cite the following evidence:

- Though researchers routinely assert that analyst forecasts are optimistic (e.g., research reviewed by Brown 1993), the evidence supporting overall optimism is contextually confined and sample-period specific. (This statement is supported by the footnote: "Abarbanell and Lehavy (2003, 142) note that "[a]fter four decades of research on the rationality of analysts' forecasts it is somewhat disconcerting that the most definitive statements observers and critics of earnings forecasters

[12] (Sundaresh Ramnath, Steve Rock, and Philip Shane, *A Review of Research Related to Financial Analysts' Forecasts and Stock Recommendations*, Social Science Research Network, June 30, 2008, at 47).

appear willing to agree on are ones for which there is only tenuous empirical support.")[13]

- Recent sample periods do not provide compelling support for forecast optimism. Brown (2001) notes that *median* forecast errors have decreased over time from slightly negative (optimistic) to zero to slightly positive (pessimistic) for all types of earnings (profits, losses, and zero net income) over the 1984-1999 time period.[14]
- In sum, conclusions regarding overall bias in analyst forecasts are subject to a variety of caveats.[15]
- Overall, biasing earnings forecasts upward to curry favor with management seems tenuous since upward biased forecasts lead to negative forecast errors, and surely management prefers to avoid negative earnings surprise.[16]
- They [Ljungqvist, et al. (2006)] suggest that analysts are concerned about reputation capital and that aggressive recommendations are counterproductive.[17]

Further, a 2010 article in Financial Analysts Journal found that analyst forecast bias declined significantly or disappeared entirely since the Global Settlement:

> *Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that of related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.*[18]

Because these analysts are solely focused on researching their subject companies, they are in the best position to provide unbiased and reliable predictions of future growth, and investors rely upon these forecasts. For this reason, Dr. Wilson's claim that

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13 Ibid, at 67
14 Ibid, at 68.
15 Ibid, at 69.
16 Ibid, at 71.
17 Ibid, at 72.
18 Armen Hovakimian and Ekkachai Saenyasiri, Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation, Financial Analysts Journal, Volume 66, Number 4, July/August 2010 at 195.

analysts' projections exceed investors' expectations has been demonstrated to be incorrect.

Dividend Yield Calculation and Adjustment

Q13. Is Dr. Wilson correct in his characterization of the dividend yield used in your DCF calculation?

A. No. On page 15, lines 16-18 of his Direct Testimony, Dr. Wilson states, "the dividend yield that Dr. Gaske uses in his DCF calculation is apparently the dividend that Bloomberg expects to be paid in 2012…"[19] This is incorrect. The dividend used in my DCF calculation is not the dividend that Bloomberg expects to be paid in 2012. As stated on page 18 of my Prepared Direct Testimony, "the dividend yields were calculated for each company by using the average *indicated annual dividend for the period* divided by the average of the stock prices for each company."[20] Stated differently, the dividend used in my DCF calculation is the average prevailing annualized dividend for each of the six months in my study period (January 2012 – June 2012). Exhibit No.___(JSG-05), Schedule 1 presents this calculation for each of my eight proxy group companies.

Q14. How does Dr. Wilson's mischaracterization of your dividend yield affect his assertion that the dividend yield adjustment is overstated?

A. Dr. Wilson's mischaracterization of my current dividend yield invalidates his claim that the dividend yield adjustment is overstated. Dr. Wilson states:

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[19] Direct Testimony of John W. Wilson, at 15.
[20] Prepared Direct Testimony of J. Stephen Gaske, at 18. *Emphasis added.*

> *Dr. Gaske's DCF calculation relates the dividend declared for payment in the future to an historic price, and the dividend in relation to price is therefore already forward looking so that the first year's growth is already reflected in the dividend yield calculation…Dr. Gaske's .625g adjustment therefore overstates the reasonably expected dividend yield in the first year of his DCF calculation.*[21]

As previously noted, the current dividend used in my DCF calculation is the average prevailing annualized dividend for each of the six months in my recent historical study period, and therefore the raw input data is *not* forward-looking. As a result, it is reasonable to adjust the current dividend yield to reflect expected dividend increases in the coming twelve months.

Q15. Do you agree with Dr. Wilson that some of your comparable natural gas distribution companies do not increase their dividends in each year and therefore your quarterly dividend yield adjustment is incorrect?

A. No, I do not. Exhibit No.___(JSG-06), Schedule 1 presents the twenty most recent quarterly dividends for each of my eight proxy group companies. The table below shows the number of times dividends were increased by each company over the last five years.

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[21] Direct Testimony of John W. Wilson, at 15-16.

Table 1: Dividend Increases for Proxy Group Companies

No. of Increases	Proxy Group Companies
5	GAS, ATO, LG, NJR, NWN, SJI
4	PNY, SWX
3	---
2	---
1	---
0	---

As shown on Table 1, six of the eight proxy group companies have increased their dividend five times in the past five years, while at the time of my study the other two proxy group companies had increased their dividend four times in the past five years.[22] In addition, it is worth noting that two of the last five years (i.e., 2008 and 2009) were characterized by a deep recession which forced many companies to conserve capital and forego dividend increases.

In addition, Value Line provides projections of annualized dividends for 2013 and 2015-17. For the current year (2013), Value Line projects that all eight of the proxy group companies will increase their dividends. During the 2015-17 period, Value Line also projects that *all* eight of the proxy group companies will increase their dividends. Exhibit No.___(JSG-07), Schedule 1 contains Value Line's dividend forecasts for 2013 and 2015-17. It is clear that Value Line, a well-respected and widely-used publication, does not share Dr. Wilson's belief that many of the proxy group companies do not increase their dividend each year.

[22] I also note that PNY subsequently increased its dividend that was payable on March 21, 2013.

Q16. Is Dr. Wilson correct in his description and assessment of the 0.625g dividend yield adjustment factor that you recommend?

A. No, he is not. Dr. Wilson's first error in this regard occurs on page 15, lines 9-11 of his Direct Testimony when he states that my 0.625g dividend yield adjustment factor "is based on the premise that the dividend in the yield component of his model is a dividend payment that investors expect to start *growing on a quarterly basis* during the first year reflected in the DCF calculation."[23] Dr. Wilson's characterization that 0.625g is premised on quarterly growth is incorrect. Instead, the model is based on the premise that growth will occur on an annual basis, and for companies that pay quarterly dividends, it is reasonable to assume that the next dividend payment is a half quarter away and the next dividend increase is a half year away.

The adjustment of quarterly dividend payments by 1+0.625g to account for future growth has a sound foundation in financial and academic theory. Equation (1) in my Prepared Direct Testimony provides the mathematical formula that demonstrates the proper increase in the *current* quarterly dividend, D, by multiplying that dividend times 1+0.625g.[24] In addition, attached to this Rebuttal Testimony as Exhibit No.___(JSG-08) is a paper which explains in more detail the mathematical derivation of my dividend yield adjustment factor, (1 + .625g).

In equation {4} of that paper, the first quarterly dividend is not multiplied by a growth factor (i.e., there is not a (1 + g) factor in the first term in brackets). The second quarterly dividend is multiplied by (1 + g), signifying a growth component that occurs a

[23] Direct Testimony of John W. Wilson, at 15. Emphasis added.
[24] See Direct Testimony of J. Stephen Gaske, at 14.

half year away. The third and fourth quarterly dividends are also multiplied by (1 + g), which means that the second, third and fourth dividends are all identical – there is no quarterly growth involved. Table 2 compares the annual growth factors in my DCF equation with the quarterly growth factors that would occur if Dr. Wilson's characterization were correct.

Table 2: Annual Growth vs. Quarterly Growth

Quarter	Gaske Annual Growth Factor	Wilson Quarterly Growth Factor
1st	----	$[(1 + g)^{0.25}]^1$
2nd	(1 + g)	$[(1 + g)^{0.25}]^2$
3rd	(1 + g)	$[(1 + g)^{0.25}]^3$
4th	(1 + g)	$[(1 + g)^{0.25}]^4$

If quarterly growth were occurring, as Dr. Wilson claims, the terms in brackets would be different every quarter. However, if annual growth is assumed to occur once each year, there is an annual increase once every fourth quarter and the growth factor would stay the same for four consecutive quarters before the next change. As it turns out, the derivation of the model causes all future quarters except the first four to drop out so that only four quarters are relevant for the DCF model that is most appropriate for my analysis.

DCF Analyses

Q17. Please describe Dr. Wilson's Constant Growth DCF analyses.

A. Exhibit No.___(JWW-1) presents Dr. Wilson's Constant Growth DCF analysis based on analyst estimates of earnings growth. Dr. Wilson calculates the ROE for each of the eight proxy group companies based on average earnings growth rates from Value Line

1 and Zacks. The dividend yield component of his calculation is the current estimated
2 dividend from Value Line for the next 12 months divided by the recent stock price. Dr.
3 Wilson does not include the required flotation cost adjustment, nor does he make an
4 adjustment for the greater risk of Montana-Dakota's Montana natural gas distribution
5 operations relative to the proxy group companies.

6 Dr. Wilson's ROE recommendation of 9.0 percent is very close to the average ROE
7 estimate produced by his Constant Growth DCF analysis using analysts' earnings
8 growth forecasts. By basing his ROE recommendation on the average Constant
9 Growth DCF results, Dr. Wilson fails to take into consideration the higher than average
10 business risk of Montana-Dakota's Montana natural gas distribution operations relative
11 to the proxy group. As shown on Exhibit No.___(JWW-1), the absolute range of DCF
12 results that Dr. Wilson calculated for the proxy group is from 7.1 percent to 11.1
13 percent. My ROE recommendation of 10.5 percent falls within the range that Dr.
14 Wilson computed and also accounts for the higher risk of Montana-Dakota's Montana
15 natural gas distribution operations compared to the proxy group.

16 **Q18. Do you have any comments on Dr. Wilson's DCF analyses based on Value**
17 **Line's dividend and book value growth rates?**

18 A. Yes, both the Value Line dividend and book value 3- to 5-year growth rates shown on
19 Exhibit No.___(JWW-2) and (JWW-3), respectively, are too short-term to adequately
20 reflect investors' long-term expectations. Growth in dividends is ultimately a result of
21 growth in earnings; therefore, long-term earnings growth forecasts are more indicative
22 of future stock valuations than near-term dividend or book value growth. My
23 Retention Growth analysis is a superior indicator of long-term book value growth

1 expectations because forecasts of retention growth rates that will be in effect provide an
2 indicator of the minimum "cruising speed" growth rate that a company should be able
3 to maintain for an indefinite period in the future. Moreover, to my knowledge Value
4 Line is the source that publishes dividend and book value growth rate forecasts. The
5 consensus earnings growth estimates of multiple analysts (such as those provided by
6 Zacks) are likely to be a better reflection of investors' expectations than the forecast of
7 a single Value Line analyst.

8 **Q19. Are the results produced by Dr. Wilson's Constant Growth DCF analyses using**
9 **dividend and book value growth rates reasonable estimates of the ROE for**
10 **Montana-Dakota's Montana natural gas distribution operations.**

11 A. No, they are not. Exhibit Nos.___(JWW-2) and (JWW-3) present Dr. Wilson's
12 Constant Growth DCF analysis based on dividend growth estimates and book value
13 growth estimates, respectively. In addition to my previously stated concerns with
14 relying on dividend and book value growth rates in the DCF analysis, Dr. Wilson fails
15 to assess the reasonableness of the ROEs produced by his analysis by reference to the
16 prevailing cost of debt for public utilities. The average cost of debt based on the
17 Moody's Baa-rated Utility Bond Index for the six month period ending January 31,
18 2013 was 4.64 percent. As shown in Column 3 of Exhibit No.___(JWW-2), based on
19 Dr. Wilson's calculated ROEs using Value Line dividend growth rates, one of the eight
20 proxy group companies has an ROE that is less than 5.64 percent (i.e., the average cost
21 of Baa-rated utility debt plus 100 basis points). Similarly, as shown in Column 3 of
22 Exhibit No.___(JWW-3), based on Dr. Wilson's calculated ROEs using Value Line

1 book value growth rates, two of the eight proxy group companies have ROEs that are
2 less than 100 basis points above the cost of debt.

3 In my opinion, return on common equity estimates that are less than the yield on Baa-
4 rated utility bonds plus 100 basis points are not plausible because they do not provide
5 investors a sufficient risk premium to compensate them for the risks associated with
6 ownership. No investors would invest in these common stocks unless they could
7 expect to earn a return substantially higher than the return available on bonds that are
8 considerably less risky.

9 **Q20. Do you have any comments on the "Fundamental Growth" DCF approach**
10 **presented in Exhibit No.___(JWW-4)?**

11 A. Yes, I do. The "Fundamental Growth" referred to in that exhibit is also referred to as
12 earnings retention growth. However, earnings retention growth is only one of many
13 ways in which a company can grow for purposes of a DCF analysis. Consequently,
14 earnings retention growth generally should be considered a minimum long-term rate of
15 growth that investors can expect to persist for the indefinite future. The consensus of
16 the projected long-term earnings growth rate expectations published by professional
17 investment analysts is often the best indicator of investors' expectations, because
18 analysts' projections incorporate all of the various sources and factors expected to affect
19 growth. In my Prepared Direct Testimony, I use a combination of earnings retention
20 growth and Zacks' earnings growth rate forecasts as a more realistic estimate of the
21 long-term future growth rates that investors expect when they buy a particular common
22 stock in the proxy group. That estimate supports my conclusion that the cost of equity
23 for Montana-Dakota's Montana natural gas operations is approximately 10.50 percent.

Q21. Have you corrected Dr. Wilson's DCF analyses for the problems you have identified in this section of your Rebuttal Testimony?

A. Yes, I have corrected Exhibit Nos._(JWW-1) through (JWW-4) to include an adjustment for flotation costs and to exclude individual DCF results that are less than 5.64 percent, which is the average cost of Baa-rated utility debt plus 100 basis points. Based on those reasonable modifications, as shown on Table 3 below (also, see Exhibit No._(JSG-09, Schedule 1 through Schedule 4), the results of Dr. Wilson's DCF analyses are generally consistent with my DCF analyses.

Table 3: Summary of Dr. Wilson's Adjusted DCF Results

	Constant Growth DCF - Earnings	Constant Growth DCF- Dividends	Constant Growth DCF – Book Value	Fundamental DCF
High	11.54%	13.10%	10.50%	11.96%
3rd Quartile	10.43%	9.13%	10.09%	11.60%
Median	9.28%	7.44%	9.88%	9.31%
1st Quartile	7.98%	6.86%	9.31%	8.37%
Low	7.38%	5.82%	5.72%	7.80%

Q22. What is your conclusion with regard to Dr. Wilson's DCF analyses for Montana-Dakota's Montana natural gas operations in this proceeding?

A. My conclusion is that Dr. Wilson's ROE estimates based on his DCF analyses are understated. Reasonable and appropriate modifications to Dr. Wilson's DCF analyses produce results that are consistent with my ROE recommendation for Montana-Dakota's Montana natural gas distribution operations.

Capital Asset Pricing Model Analysis

Q23. Please describe your disagreement with Dr. Wilson's use of the Capital Asset Pricing Model to estimate the cost of common equity capital for Montana-Dakota's Montana natural gas distribution operations.

A. I have several areas of disagreement concerning the Capital Asset Pricing Model ("CAPM"). On a conceptual level, the CAPM is an unreliable method for estimating the cost of common equity capital because the input assumptions are extremely subjective, unreliable and are based on historical rather than forecasted information. The CAPM has many weaknesses that make it an unreliable method for estimating the cost of common equity capital. In that regard, Fama and French observed:

> *Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model.*[25]

In particular, Beta cannot be measured accurately and is not a reliable predictor of stock returns. For example, when the underlying calculations of Beta are examined, it is very common to find that the "R-squared" statistic is so low that there is no statistical significance to the Beta estimate. Moreover, in the most comprehensive test of the CAPM hypothesis that has ever been conducted, Fama and French found that the level of Beta does not correlate well with the returns on common stocks. Instead, Fama and French found that firm size (with smaller companies requiring higher returns) and

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[25] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, Number 3, Summer 2004, at 25.

1 market-to-book ratios are the two variables that best explain the returns for common
2 stocks.[26] With regard to these findings Value Line commented as follows:

> 3 *Indeed, Professor Fama concluded, 'The fact is that Beta, as the sole variable*
> 4 *explaining returns on stocks, is dead.' These findings support previous studies that*
> 5 *have called into question the real-world applicability of the CAPM Beta, including*
> 6 *papers by Keim (Financial Analysts Journal, 1986), and Roll (Journal of Financial*
> 7 *Economics, 1977). Never before, however, has the lack of a statistically significant*
> 8 *relationship between beta and return been so rigorously and dramatically*
> 9 *established.*[27]

10 Fama and French also commented on the reliability of Beta in predicting equity returns,
11 especially for stocks with lower betas, such as many regulated public utilities:

> 12 *But empirical work, old and new, tells us that the relation between Beta and average*
> 13 *return is flatter than predicted by the Sharpe-Lintner version of the CAPM. As a*
> 14 *result, CAPM estimates for the cost of equity for high beta stocks are too high*
> 15 *(relative to historical average returns) and estimates of low Beta stocks are too low*
> 16 *(French and Blume, 1970).*[28]

17 In addition to the proven inaccuracy and unreliability of Beta, the market risk premium,
18 another important component of the CAPM equation, changes over time. It is not
19 appropriate to rely on historical market risk premia, as Dr. Wilson has done, because
20 the relationships between equity returns and bond yields may not reflect the current
21 circumstances.

22 In conclusion, the CAPM method hinges on two input assumptions, each of which is
23 highly subjective and based on historical information rather than forward-looking
24 expectations.

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26 Fama and French, "The Cross-Section of Expected Stock Returns," Journal of Finance, Vol. XLVII, No. 2, June 1992, 427-465.

27 Value Line Industry Review, March 13, 1992, p. 1-8.

28 "The Capital Asset Pricing Model: Theory and Evidence," Journal of Economic Perspectives, Volume 18, Number 3, Summer 2004, Eugene F. Fama and Kenneth R. French, at 43-44.

Q24. Please elaborate on why the CAPM is an unreliable method for estimating the cost of common equity capital.

A. Application of the CAPM – and more specifically, estimation of investors' expectation of a forward-looking "Beta" – is based on the concept that the value of each individual stock (or other investment) has a reasonably fixed, known and measureable sensitivity to changes in the value of a market portfolio consisting of all other investments in the economy. However, there are several fundamental problems with the CAPM that have been established in the finance literature.

First, there are no theoretically correct time intervals for measuring the returns and risks that are relevant for investors, but the calculated level of Beta can be very different when different measurement intervals are used. Therefore, the selection of time intervals for measuring Beta – and by extension the level of Beta – is an arbitrary decision that cannot be defended on either theoretical or empirical grounds.

Second, the Beta and risk-premium inputs to the CAPM generally are based on historical rather than forecasted information. However, there is no theoretically correct *historical* time period (e.g., two years, five years, 10 years, etc.) over which to measure the *future* Beta that investors currently expect, and there is significant evidence that Beta does not remain constant from one period to the next. Thus, a Beta measured using historical data cannot provide an accurate estimate of the level of risk investors currently expect on a forward-looking basis.

Third, although several early studies conducted approximately 40 years ago were thought to have validated the accuracy of the CAPM, more complete empirical studies since that time have shown that the CAPM is not accurate and that the results of early

1 studies may have been a statistical anomaly. In general, Beta estimates do not have a
2 strong correlation with the returns earned on investments and therefore Beta estimates
3 would not be expected to provide valid estimates of the relative cost of common equity.

4 **Q25. Why is there a fundamental problem with selecting the time intervals used in**
5 **calculating Beta?**

6 A. Although Beta is supposed to be the measure of how sensitive the return on a particular
7 stock is relative to the return on a diversified market portfolio, there are no theoretically
8 correct time intervals for measuring that sensitivity. For example, one could measure
9 Beta using an annual interval that calculates the relationship between the return on a
10 stock and the return on the market portfolio from one year to the next. However, it
11 would be equally "correct" to measure Beta by calculating the relationship between the
12 returns that occur each month. Similarly, the theory allows Beta to be measured using
13 the rates of return that occur weekly, or daily, or any other time period the analyst
14 chooses. Because there are no theoretically correct time intervals for measuring the
15 returns, it is an arbitrary choice as to which time intervals to use. Many studies,
16 including Levhari and Levy[29] and Hawawini[30], have shown that the level of Beta can be
17 very different depending on the time interval selected for measuring returns. For
18 example, Hawawini cites Eastman Kodak as one example where the Beta was 1.25
19 based on daily returns, but it was 0.93 based on monthly returns.[31] Discrepancies of
20 this magnitude are not unusual when different return intervals are used to estimate the

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29 Levhari, D. and Levy, H., "The Capital Asset Pricing Model and the Investment Horizon," *Review of Economics and Statistics* (February 1977), 92-104.

30 Hawawini, G., "Why Beta Shifts as the Return Interval Changes," *Financial Analysts Journal* (May-June 1983), 73-77.

31 Ibid., p. 73.

value of Beta. Because the level of Beta is sensitive to the time intervals of the returns used in its calculation, and the time intervals used are selected arbitrarily, the level of Beta used in a CAPM analysis ultimately is an arbitrarily selected number. An arbitrarily selected Beta cannot be considered to be a reasonable or accurate method for estimating the cost of common equity.

Q26. In regard to the second problem, why is it unreliable to simply use historical data to calculate the current forward-looking cost of common equity?

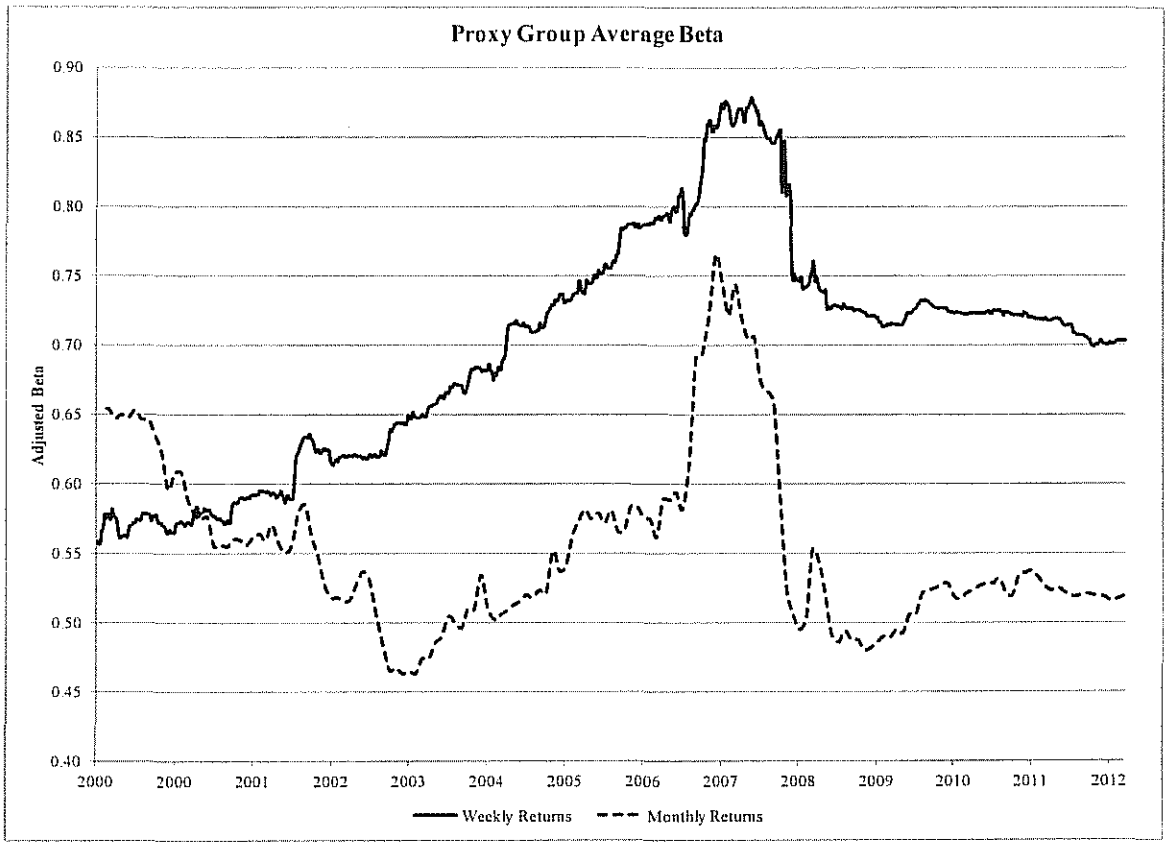
A. Investors' current requirements and expectations for the future are not necessarily the same as the past. Thus, even if we ignore the problem that there is no theoretically accurate or reliable way to measure what "Beta" has been in the past, there is no reason to believe that investors currently perceive the same risks and require the same premiums for risk that were experienced in the past. Instead, investors' current expectations for "Beta" are forward-looking and not historical. Moreover, it is not unusual for calculated Betas to shift from one period to the next in ways that appear to be unrelated to any changes in risk.

In addition to the proven inaccuracy and unreliability of Beta, the market risk premium is another important component of the CAPM equation that changes over time. Historical market risk premia are less reliable than reasonable forecasts because the historical average relationships between equity returns and bond yields may not reflect the current circumstances.

Q27. Have you performed any analysis to evaluate whether the underlying calculations affect the average Beta coefficient for the companies in your proxy group?

A. Yes, I have. In order to evaluate the effect of the underlying methodology, I calculated the average Beta coefficient for the proxy group companies using the Value Line methodology from January 2000 through January 2013. Value Line, which is the source of Beta used in Dr. Wilson's CAPM analysis, calculates Betas based on five years of weekly returns of an individual stock compared to the New York Stock Exchange Composite Index returns over that same period. In order to evaluate whether Beta varies depending on the intervals for measuring returns, I modified the Value Line methodology to use five years of monthly returns rather than weekly returns. As shown in Figure 2, there has been a substantial difference in the rolling average Beta coefficient for the proxy group companies depending on whether Beta is calculated using weekly or monthly returns. Consequently, we have no way of knowing which (if any) of these calculations might have been correct, and we have no way of knowing what the value of Beta was during any of these time periods. Moreover, the large changes in these Betas during the past decade indicate that historical Betas are not sufficiently stable to allow one to estimate investors' future expectations for the value of Beta.

Figure 2: Rolling Average Value Line Beta for Proxy Group Companies



Q28. Is your concern with the use of the CAPM heightened in light of current market conditions?

A. Yes, it is. Another concern regarding the use of the CAPM under current market conditions is that it produces anomalous results. Although extreme pressures on capital markets have subsided somewhat from their height in 2008 and 2009, investors still require a higher cost of common equity capital. However, the CAPM results have been falling in recent years because two of its inputs, the risk-free rate and the market risk premium, are declining for reasons that have nothing to do with the cost of common equity capital for regulated utilities.

1 The risk-free rate, as indicated by the 30-year U.S. Treasury bond, has decreased in part
2 due to the "flight to quality" that has occurred as investors move money out of more
3 risky corporate bonds and common stocks to the relative safety of U.S. government
4 bonds. More important, however, is the fact that the yield on U.S. Treasury securities
5 does not reflect the requirements of actual investors in the market. Instead, the Federal
6 Reserve Board has been consciously manipulating Treasury yields through a variety of
7 programs that prevent those yields from reflecting the requirements of real investors.
8 As a result, low yields on U.S. Treasury securities are not a reasonable indicator of the
9 cost of capital for common stocks at this time. Likewise, the *historical* long-term market
10 risk premium has fallen from 7.10 percent to 6.60 percent due to dramatic declines in
11 large company stock prices that occurred during 2008 and 2009. These two factors
12 have resulted in CAPM results moving lower while investors' risk aversion and required
13 equity returns have been increasing.

14 The unreliability of the CAPM under current market conditions is evident based on the
15 results of Dr. Wilson's application of that model. As shown on Exhibit No.___(JWW-
16 5), depending on the input assumptions, Dr. Wilson's CAPM results range from 2.97
17 percent to 9.59 percent, with a midpoint of 6.28 percent. At a time when the average
18 yield on Moody's Baa-rated public utility bonds is approximately 4.64 percent, a CAPM
19 estimate of 2.97 percent is clearly implausible. Therefore, Dr. Wilson's CAPM results
20 are not consistent with either financial market conditions or comparable returns in
21 other jurisdictions. As a result, his CAPM results should be disregarded.

1 **Flotation Cost Adjustment**

2 **Q29. What arguments does Dr. Wilson provide in opposition to your use of a flotation**
3 **cost adjustment?**

4 A. Dr. Wilson states that "assuming a flotation cost of 4 percent for all of MDU's
5 common equity capital, as Dr. Gaske does, greatly overstates MDU's actual common
6 stock issuance costs."[32] As support for his position, Dr. Wilson claims that natural gas
7 distribution companies (including MDU) realize equity growth through retained
8 earnings and not through new public stock issuances. Dr. Wilson also contends that
9 retained earnings and other forms of equity capital like dividend reinvestment plans and
10 parent company equity infusions do not incur issuance costs. Regarding MDU's
11 Montana operations specifically, Dr. Wilson states that these operations have generated
12 substantial retained earnings but have grown little during the past several decades and
13 that future growth expectations are modest. For these reasons, Dr. Wilson believes that
14 there is no realistic basis for the flotation cost adjustment that I have proposed.[33]

15 **Q30. What is your response to Dr. Wilson on this issue?**

16 A. Dr. Wilson's arguments are off point because they misstate the purpose of the flotation
17 cost adjustment explained in my Prepared Direct Testimony.[34] Under the capital
18 attraction standard, an allowed rate of return must be sufficient to *enable* the regulated
19 company to attract capital in primary capital markets on reasonable terms. This
20 standard applies equally both to companies that have no need to attract capital, and to

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32 Direct Testimony of John W. Wilson, at 16.
33 Direct Testimony of John W. Wilson, at 16-17.
34 See Prepared Direct Testimony of J. Stephen Gaske, at 15-16.

1 companies that have enormous needs for new capital. In the absence of a flotation cost
2 adjustment, the allowed rate of return would reflect the rate of return required in the
3 secondary market where ownership of stock certificates is bought and sold with no
4 effect on the investment capital available to the utility. That secondary market rate of
5 return is fundamentally different from the rate of return that the utility requires in order
6 to attract capital in the primary market.

7 The essence of Dr. Wilson's argument is that the allowed rate of return should not be
8 sufficient to enable a company to attract capital unless the company can demonstrate an
9 immediate need to attract capital. At all other times, Dr. Wilson would have the
10 Commission ignore the capital attraction standard.

11 **Q31. Is there support in academic literature for your approach, which multiplies the**
12 **entire return by a specified factor to adjust for flotation costs?**

13 A. Yes. Myron Gordon, who is credited with developing the DCF model for estimating
14 rate of return, has stated that a regulatory agency should set the allowed rate of return
15 greater than the investor return requirement so as to allow the firm to issue stock at a
16 price that will yield net proceeds equal to book value. Professor Gordon advocates the
17 following adjustment:

18 *The agency need only estimate the proportion that the proceeds per share on an issue*
19 *bear to the price of the stock and adjust the allowed rate of return so that the price per*
20 *share is the indicated ratio of the book value per share. If the proceeds on an issue*
21 *are 91 percent of market price, the agency should maintain market price at about*
22 *110 percent of book value.*[35]

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[35] Myron J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State University, 1974, pages 165-166.

1 In order to meet this requirement, the flotation cost adjustment must be applied to the
2 entire rate of return. The flotation cost adjustment that I have proposed attempts to
3 meet that same standard.

4 **Q32. In response to Dr. Wilson's testimony, have you calculated the flotation costs**
5 **based on MDU's most recent equity issuances?**

6 A. Yes. As shown on Exhibit No.___(JSG-10), Schedule 1,based on the three most recent
7 common equity issuances by MDU Resources, the Company's average flotation costs
8 have been approximately 3.6 percent, and the most recent issuance incurred costs of 4.2
9 percent. This is generally consistent with the flotation costs for the proxy group
10 companies, which I calculated as 3.81 percent, as shown on Schedule 3 of Exhibit
11 No.___(JSG-2). Therefore, I continue to support 4.0 percent as a reasonable estimate
12 of the required flotation cost adjustment.

13 **Relative Risk of Montana-Dakota's Montana Operations**

14 **Q33. Please summarize your areas of disagreement with Dr. Wilson concerning the**
15 **relative business and regulatory risks associated with Montana-Dakota's**
16 **Montana natural gas distribution operations.**

17 A. There are four primary areas of disagreement regarding Dr. Wilson's risk assessment for
18 Montana-Dakota's Montana natural gas distribution operations. Specifically, Dr.
19 Wilson (1) disagrees that there should be an adjustment for the small size of Montana-
20 Dakota's Montana natural gas distribution operations vis-à-vis the proxy group, (2) fails
21 to take into consideration that the Company's natural gas distribution operations are
22 heavily dependent on an undiversified local economy, (3) fails to take into account the
23 fact that Montana-Dakota's Montana natural gas distribution operations recover a

substantial portion of its fixed costs through the volumetric component of rates and does not have a revenue decoupling mechanism, unlike the vast majority of proxy group companies[36], and (4) fails to recognize that the perceived regulatory risk faced by Montana-Dakota is above average relative to that of the proxy companies.

Q34. Please explain your disagreement with Dr. Wilson's assessment of the Company's business risk associated with small size.

A. Dr. Wilson disagrees that there is significant risk associated with the small size of the Montana-Dakota's Montana natural gas distribution operations compared to the proxy group. Specifically, Dr. Wilson contends that small size is not a relevant risk for Montana-Dakota's Montana natural gas distribution operations because "all of MDU's common equity capital is raised on a consolidated basis by the utility's parent, MDU Resources Group, Inc., which is considerably larger than most of Dr. Gaske's comparable gas distribution utility companies."[37]

I disagree with Dr. Wilson's position on this issue because the purpose of this proceeding is to establish the authorized ROE for Montana-Dakota's Montana natural gas distribution business as if that business were a stand-alone entity that is independently going to the capital markets to raise equity capital in order to serve Montana jurisdictional customers. In that regard, as explained in my Prepared Direct Testimony, Montana-Dakota's Montana natural gas distribution operations are considerably smaller than the operations of any of the proxy companies and a small

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[36] As indicated in Dr. Gaske's prepared Direct Testimony, more than 65 percent of customers served by the proxy group companies are located in jurisdictions where the operating company has an approved revenue decoupling mechanism.

[37] Direct Testimony of John W. Wilson, at 32.

fraction of the typical proxy company.[38] Dr. Wilson's analysis has not accounted for the risks associated with small size, which I have estimated might require a return that is more than 100 basis points higher than the return required for the typical proxy company.[39]

Morningstar (formerly Ibbotson Associates) has documented the significantly higher returns that are generally associated with utilities that have small market capitalizations. Specifically, a senior consultant with Ibbotson Associates noted:

> *For small utilities, investors face additional obstacles, such as smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.*[40]

Similarly, as discussed earlier, Fama and French found that firm size is one of the most significant factors affecting the returns on stocks, with higher returns strongly associated with smaller firms.[41] For these reasons, it is appropriate to select an authorized ROE above the midpoint of the range of reasonableness, as I have done, to account for the Company's small size.

Q35. How does Dr. Wilson's failure to consider relevant business and regulatory risks affect his ROE recommendation for Montana-Dakota's Montana natural gas distribution operations?

A. By failing to consider relevant business and regulatory risks, such as those discussed in my Prepared Direct Testimony, Dr. Wilson's ROE recommendation is not based on a

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38 Prepared Direct Testimony of J. Stephen Gaske, at 27.
39 Prepared Direct Testimony of J. Stephen Gaske, at 29.
40 Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.
41 Fama and French, "The Cross-Section of Expected Stock Returns," Journal of Finance, Vol. XLVII, No. 2, June 1992, 427-465.

comparison of the business and financial risks of Montana-Dakota's Montana natural gas distribution operations relative to the proxy group companies. Rather, Dr. Wilson has recommended an ROE of 9.0 percent, which is the mean result of his Constant Growth DCF analysis using earnings growth. Had Dr. Wilson taken into consideration the higher business and regulatory risks of Montana-Dakota's Montana natural gas distribution operations, his ROE recommendation would have been significantly higher than the mean DCF result for the proxy group.

Earnings Yield Estimates

Q36. At pages 26-31 of his Direct Testimony, Dr. Wilson presents an analysis that he refers to as a "Comparable Earnings" analysis. Is it correct to describe this as a Comparable Earnings analysis?

A. No, it is not. Dr. Wilson's "Comparable Earnings" analysis actually is something that is widely-referred to as an "Earnings Yield." In his analysis, Dr. Wilson takes the projected rate of return on the book value of equity for the eight proxy group companies and divides it by the projected market-to-book ratio for those companies. Algebraically, his calculation consists of:

$$\frac{\textit{Return on Equity}}{\textit{Market-to-Book Ratio}} = \frac{\dfrac{\textit{Earnings per Share}}{\textit{Book Value per Share}}}{\dfrac{\textit{Price per Share}}{\textit{Book Value per Share}}}$$

Because book value per share appears in both the numerator and the denominator, it cancels itself out, and Dr. Wilson's "Comparable Earnings" formula is really:

$$\frac{\textit{Earnings per Share}}{\cancel{\textit{Book Value per Share}}} \times \frac{\cancel{\textit{Book Value per Share}}}{\textit{Price per Share}} = \frac{\textit{Earnings per Share}}{\textit{Price per Share}}$$

1 Earnings per share divided by price per share equals the earnings yield, or the inverse of
2 the P/E ratio. This calculation is neither a Comparable Earnings analysis, nor a rate of
3 return, nor a cost of capital estimate. In short, it has no perceptible relevance for the
4 task of estimating an allowed rate of return.

5 **Q37. Please summarize your Rebuttal Testimony.**

6 A. The return on common equity recommended by Dr. Wilson is inadequate to meet the
7 tests of a reasonable rate of return because it is based on flawed analyses and is
8 substantially lower than the authorized ROEs for other natural gas distribution utilities,
9 many of which have lower business and regulatory risk than Montana-Dakota's
10 Montana natural gas distribution operations. In summary, Dr. Wilson has
11 underestimated the risks that investors perceive in regard to the Company's natural gas
12 distribution operations in Montana. By contrast, the evidence presented in my
13 Prepared Direct Testimony supports the reasonableness of my recommended ROE of
14 10.5 percent.

15 **Q38. Does this conclude your Prepared Rebuttal Testimony?**

16 A. Yes.

South Jersey Industries, Inc.
Part II

	2011	2010	2009
Operating Income (Loss):			
Gas Utility Operations	$ 102,663	$ 90,700	$ 81,439
Wholesale Energy Operations	16,225	6,154	29,601
Retail Energy Operations:			
Retail Gas and Other Operations	478	1,065	78
Retail Electric Operations	1,755	13,051	(7,459)
On-Site Energy Production	2,254	4,063	5,309
Appliance Service Operations	(1,539)	432	1,361
Subtotal Retail Energy Operations	2,948	18,611	(711)
Corporate and Services	(229)	1,027	781
Total Operating Income	$ 121,607	$ 116,492	$ 111,110

* * * * *

	2011	2010
Identifiable Assets:		
Gas Utility Operations	$ 1,615,723	$ 1,468,635
Wholesale Energy Operations	159,424	237,978
Retail Energy Operations:		
Retail Gas and Other Operations	14,659	21,532
Retail Electric Operations	31,225	37,383
On-Site Energy Production	275,053	147,064
Appliance Service Operations	11,335	18,528
Subtotal Retail Energy Operations	332,272	224,507
Discontinued Operations	224	890
Corporate and Services	156,252	168,788
Intersegment Assets	(16,385)	(24,183)
Total Identifiable Assets	$ 2,247,510	$ 2,076,615

Source: South Jersey Industries 2011 SEC Form 10-K, pages 65 and 66.

Montana-Dakota Utilities Co.

Dividend Yields

January 2012 -- June 2012

Company	Ticker	Average Low Price	Average High Price	Average Price	Average Annualized Dividend	Average Dividend Yield
AGL Resources Inc.	GAS	$ 38.26	$ 40.73	$ 39.50	$ 1.81	4.59%
Atmos Energy Corp.	ATO	$ 31.41	$ 33.47	$ 32.44	$ 1.38	4.25%
Laclede Group, Inc.	LG	$ 38.64	$ 41.10	$ 39.87	$ 1.66	4.16%
New Jersey Resources Corp.	NJR	$ 43.66	$ 46.87	$ 45.26	$ 1.52	3.36%
Northwest Natural Gas Co.	NWN	$ 45.17	$ 47.69	$ 46.43	$ 1.78	3.83%
Piedmont Natural Gas Co., Inc.	PNY	$ 30.50	$ 32.82	$ 31.66	$ 1.19	3.75%
South Jersey Industries, Inc.	SJI	$ 49.49	$ 53.16	$ 51.33	$ 1.61	3.14%
Southwest Gas Corp.	SWX	$ 40.86	$ 43.57	$ 42.21	$ 1.10	2.61%
Average						**3.71%**

			Price			Annualized
			Low	High	Average	Dividend
AGL Resources Inc.	GAS	Jan-12	$ 40.64	$ 42.88	$ 41.76	$ 1.80
		Feb-12	39.44	42.00	40.72	1.80
		Mar-12	38.42	40.14	39.28	1.80
		Apr-12	37.75	39.75	38.75	1.80
		May-12	36.59	40.29	38.44	1.84
		Jun-12	36.72	39.32	38.02	1.84
			$ 38.26	**$ 40.73**	**$ 39.50**	**$ 1.81**
Atmos Energy Corp.	ATO	Jan-12	$ 31.94	$ 33.83	$ 32.89	$ 1.38
		Feb-12	30.68	33.05	31.87	1.38
		Mar-12	30.39	31.60	31.00	1.38
		Apr-12	30.80	32.65	31.73	1.38
		May-12	32.10	33.93	33.02	1.38
		Jun-12	32.52	35.77	34.15	1.38
			$ 31.41	**$ 33.47**	**$ 32.44**	**$ 1.38**
Laclede Group, Inc.	LG	Jan-12	$ 39.91	$ 41.93	$ 40.92	$ 1.66
		Feb-12	40.67	43.00	41.84	1.66
		Mar-12	38.58	41.46	40.02	1.66
		Apr-12	38.45	39.98	39.22	1.66
		May-12	37.70	40.39	39.05	1.66
		Jun-12	36.53	39.86	38.20	1.66
			$ 38.64	**$ 41.10**	**$ 39.87**	**$ 1.66**

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Laclede Group, Inc.	LG	$ 38.64	$ 41.10	$ 39.87	$ 1.66	4.16%
New Jersey Resources Corp.	NJR	$ 43.66	$ 46.87	$ 45.26	$ 1.52	3.36%
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South Jersey Industries, Inc.	SJI	$ 49.49	$ 53.16	$ 51.33	$ 1.61	3.14%
Southwest Gas Corp.	SWX	$ 40.86	$ 43.57	$ 42.21	$ 1.10	2.61%
Average						**3.71%**

			Price			Annualized
			Low	High	Average	Dividend
New Jersey Resources Corp.	NJR	Jan-12	$ 46.82	$ 50.28	$ 48.55	$ 1.52
		Feb-12	46.63	49.66	48.15	1.52
		Mar-12	43.86	47.03	45.45	1.52
		Apr-12	42.06	45.50	43.78	1.52
		May-12	41.47	44.38	42.93	1.52
		Jun-12	41.11	44.37	42.74	1.52
			$ 43.66	**$ 46.87**	**$ 45.26**	**$ 1.52**
Northwest Natural Gas Co.	NWN	Jan-12	$ 46.60	$ 48.83	$ 47.72	$ 1.78
		Feb-12	45.74	49.49	47.62	1.78
		Mar-12	44.40	46.52	45.46	1.78
		Apr-12	43.90	46.08	44.99	1.78
		May-12	44.87	46.66	45.77	1.78
		Jun-12	45.50	48.56	47.03	1.78
			$ 45.17	**$ 47.69**	**$ 46.43**	**$ 1.78**
Piedmont Natural Gas Co., Inc.	PNY	Jan-12	$ 32.38	$ 34.63	$ 33.51	$ 1.16
		Feb-12	32.25	34.00	33.13	1.16
		Mar-12	30.70	32.96	31.83	1.20
		Apr-12	29.05	31.61	30.33	1.20
		May-12	28.90	30.71	29.81	1.20
		Jun-12	29.71	33.03	31.37	1.20
			$ 30.50	**$ 32.82**	**$ 31.66**	**$ 1.19**

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Laclede Group, Inc.	LG	$ 38.64	$ 41.10	$ 39.87	$ 1.66	4.16%
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South Jersey Industries, Inc.	SJI	$ 49.49	$ 53.16	$ 51.33	$ 1.61	3.14%
Southwest Gas Corp.	SWX	$ 40.86	$ 43.57	$ 42.21	$ 1.10	2.61%
Average						**3.71%**

			Price			Annualized
			Low	High	Average	Dividend
South Jersey Industries, Inc.	SJI	Jan-12	$ 54.09	$ 57.99	$ 56.04	$ 1.61
		Feb-12	51.91	56.15	54.03	1.61
		Mar-12	49.55	52.06	50.81	1.61
		Apr-12	47.42	51.03	49.23	1.61
		May-12	46.52	49.84	48.18	1.61
		Jun-12	47.46	51.90	49.68	1.61
			$ 49.49	**$ 53.16**	**$ 51.33**	**$ 1.61**
Southwest Gas Corp.	SWX	Jan-12	$ 40.51	$ 43.22	$ 41.87	$ 1.06
		Feb-12	41.50	42.98	42.24	1.06
		Mar-12	41.89	43.64	42.77	1.06
		Apr-12	40.76	43.52	42.14	1.06
		May-12	41.03	43.42	42.23	1.18
		Jun-12	39.46	44.64	42.05	1.18
			$ 40.86	**$ 43.57**	**$ 42.21**	**$ 1.10**

Source: Bloomberg Professional

Montana-Dakota Utilities Co.

Twenty Most Recent Dividends for Proxy Group Companies

GAS		ATO		LG		NJR		NWN		PNY		SJI		SWX	
Ex-Date	Amount	Ex-Date	Amount	Ex-Date	Amount	Ex-Date	Amount	Ex-Date	Amount	Ex-Date	Amount	Ex-Date	Amount	Ex-Date	Amount
04/30/08	0.4200	05/01/08	0.3250	04/24/08	0.3750	05/16/08	0.2800	04/04/08	0.3750	03/06/08	0.2600	05/27/08	0.2700	02/28/08	0.2250
08/01/08	0.4200	08/05/08	0.3250	08/01/08	0.3750	07/16/08	0.2800	07/01/08	0.3750	06/06/08	0.2600	08/27/08	0.2700	05/07/08	0.2250
10/30/08	0.4200	11/11/08	0.3300	11/20/08	0.3850	11/13/08	0.3100	10/01/08	0.3950	09/04/08	0.2600	11/24/08	0.2975	09/16/08	0.2250
02/05/09	0.4300	02/03/09	0.3300	01/29/09	0.3850	01/22/09	0.3100	01/07/09	0.3950	12/18/08	0.2600	02/23/09	0.2975	11/14/08	0.2250
04/29/09	0.4300	05/05/09	0.3300	04/30/09	0.3850	05/15/09	0.3100	04/03/09	0.3950	03/06/09	0.2700	05/26/09	0.2975	02/27/09	0.2375
07/30/09	0.4300	08/04/09	0.3300	07/31/09	0.3850	09/01/09	0.3100	07/24/09	0.3950	06/05/09	0.2700	08/10/09	0.2975	05/06/09	0.2375
10/28/09	0.4300	11/11/09	0.3350	11/19/09	0.3950	12/01/09	0.3400	10/01/09	0.4150	09/03/09	0.2700	11/23/09	0.3300	09/14/09	0.2375
02/04/10	0.4400	02/02/10	0.3350	01/28/10	0.3950	01/27/10	0.3400	01/19/10	0.4150	12/17/09	0.2700	01/25/10	0.3300	11/17/09	0.2375
04/28/10	0.4400	05/05/10	0.3350	04/30/10	0.3950	05/13/10	0.3400	04/05/10	0.4150	02/26/10	0.2800	04/26/10	0.3300	02/26/10	0.2500
07/28/10	0.4400	08/04/10	0.3350	07/30/10	0.3950	07/15/10	0.3400	07/06/10	0.4150	06/04/10	0.2800	06/21/10	0.3300	05/05/10	0.2500
10/28/10	0.4400	11/03/10	0.3400	11/18/10	0.4050	11/17/10	0.3600	10/04/10	0.4350	09/02/10	0.2800	11/22/10	0.3650	09/14/10	0.2500
02/08/11	0.4500	02/08/11	0.3400	01/27/11	0.4050	01/27/11	0.3600	01/13/11	0.4350	12/16/10	0.2800	01/24/11	0.3650	11/16/10	0.2500
05/04/11	0.4500	05/04/11	0.3400	04/29/11	0.4050	05/12/11	0.3600	04/06/11	0.4350	03/04/11	0.2900	05/02/11	0.3650	02/24/11	0.2650
08/02/11	0.4500	08/03/11	0.3400	07/29/11	0.4050	07/13/11	0.3600	07/01/11	0.4350	06/03/11	0.2900	07/05/11	0.3650	05/04/11	0.2650
11/01/11	0.4500	11/09/11	0.3450	11/17/11	0.4150	11/16/11	0.3800	10/04/11	0.4450	09/08/11	0.2900	11/21/11	0.4025	09/20/11	0.2650
11/15/11	0.4600	02/07/12	0.3450	01/26/12	0.4150	01/26/12	0.3800	01/10/12	0.4450	12/16/11	0.2900	01/23/12	0.4025	11/15/11	0.2650
05/02/12	0.4600	05/02/12	0.3450	04/27/12	0.4150	05/17/12	0.3800	04/10/12	0.4450	03/08/12	0.3000	04/23/12	0.4025	02/27/12	0.2950
08/01/12	0.4600	08/08/12	0.3450	07/27/12	0.4150	07/12/12	0.4000	07/05/12	0.4450	06/07/12	0.3000	07/05/12	0.4025	05/09/12	0.2950
11/01/12	0.4600	11/07/12	0.3500	11/14/12	0.4250	11/15/12	0.4000	10/08/12	0.4550	09/14/12	0.3000	11/19/12	0.4425	09/18/12	0.2950
02/05/13	0.4700	02/06/13	0.3500	01/31/13	0.4250	01/24/13	0.4000	01/08/13	0.4550	12/13/12	0.3000	01/21/13	0.4425	11/09/12	0.2950
No. of Increases	5		5		5		5		5		4		5		4

Source: Bloomberg Professional

Montana-Dakota Utilities Co.

Value Line Dividends Declared per Share

	GAS	ATO	LG	NJR	NWN	PNY	SJI	SWX
2011 (actual)	1.90	1.36	1.61	1.44	1.75	1.15	1.50	1.06
2012 (actual) [1]	1.74	1.38	1.66	1.52	1.79	1.19	1.65	1.18
2013 (forecast)	1.84	1.40	1.74	1.60	1.83	1.23	1.82	1.30
2015-17 (forecast)	1.96	1.48	1.84	1.68	1.96	1.35	2.30	1.60
Increase in 2012?	**No**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Increase in 2013?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Increase in 2015-17?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Source Value Line, dated December 7, 2012
[1] Dividends for GAS, NWN, SJI, and SWX are Value Line estimates as of December 7, 2012

DOES THE FERC DCF MODEL REFLECT THE COMMISSION'S REASONING?

by
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In its Order No. 420, issued May 20, 1985, the Federal Energy Regulatory Commission specified that the following Discounted Cash Flow (DCF) rate of return model should be used in establishing the annual generic benchmark rate of return for electric utilities[1]:

$$k = \frac{Do}{Po} [1 + .5 g] + g \qquad (1)$$

where,

k = the cost of common equity capital

Do = the current annual dividend (most recent quarterly dividend multiplied by four)

Po = the current price per share

g = the expected annual dividend growth rate.

In subsequent generic rate of return proceedings the Commission has reaffirmed the use of this model,[2] even though it fails to reflect the Commission's own assumptions regarding the payment of dividends. Whether any given cost-of-capital model is "correct" depends on how well it reflects reasonable assumptions. The purpose of this article is to demonstrate the contrast between the FERC DCF rate of return model and the Commission's stated assumptions regarding the pattern of dividends and dividend increases expected by investors on average.

The reasoning used to justify the FERC DCF model in Order

No. 420 was apparently an attempt to split the difference between the basic constant growth DCF model which assumes that dividends are received annually:

$$k = \frac{Do}{Po} [1 + g] + g \qquad (2)$$

and the constant growth DCF model which assumes that dividends are received continuously:

$$k = \frac{Do}{Po} + g \qquad (3)$$

The Commission believed, with justification, that a realistic model would yield cost of capital estimates that fall somewhere between the estimates produced by equations (2) and (3).

FERC Assumptions

In its Order No. 442, FERC described the assumptions that it thought would be reflected in its DCF model (equation (1)) when it wrote the following:

> The Commission's analytical process in deciding to reevaluate the model formulation was to start with the general form of the DCF model and make certain assumptions. The first two are the standard assumptions that dividends grow at the same rate each year, and that the required rate of return is the same in every period. The next two assumptions reflect (1) the fact that dividends are paid quarterly, and (2) that the annual dividend increase, on average, occurs halfway through the year. The latter assumption was made in the model used in Order No. 420. The Commission there noted that "from the perspective of the average company or the average investor, the next dividend increase is a half year away."3 (emphasis added)

The Commission reiterated its assumption that a dividend increase occurs at mid-year for the typical utility at several other

points in Order No. 442.[4] In addition, both the Commission and Staff, in its analyses, have consistently adopted the implicit assumption that the next quarterly dividend will be received in three months.

The DCF model adopted by FERC does not reflect the Commission's assumptions expressed in various orders, however. To see why, it is helpful to assume a hypothetical utility that pays quarterly dividends on a calendar basis on March 31, June 30, September 30, and December 31 each year. Annual dividend increases occur with the fourth quarterly dividend paid each year. If we assume that the middle of the year occurs on July 1, the next end-of-year dividend increase is six months (or a "half year") away.

Analogously, the FERC model assumes that the middle of the calendar year occurs on April 1 and that, on average, annual end-of-year dividend increases are <u>nine months</u> away. This modelling error is described in greater detail in the next section.

Alternatively, the FERC model can be derived by assuming that, on average, the next annual dividend increase is expected in six months, but that the next quarterly dividend payment is expected today. Neither FERC nor its Staff has ever expressed or implied the assumption that, on average, investors expect to receive the next dividend today, however.

<u>A Model Based On FERC Assumptions</u>

If we assume that the middle of the year occurs on July 1, the investor can expect the next dividend at the current rate in three months and the end-of-year dividend increase in six months.

Incorporating the assumptions that "the next dividend increase is a half year away" and the next dividend is one quarter away results in the following DCF model:

$$k = \frac{Do}{4Po}\left[(1+k)^{.75} + (1+g)(1+k)^{.5} + (1+g)(1+k)^{.25} + (1+g)\right] + g \qquad (4)$$

The only difference between this model and the FERC model is that this model multiplies the second term in brackets by 1+g. Equation (4) assumes that the next dividend at the current rate will be received in three months, or one-quarter year. The $(1+k)^{.75}$ term in brackets is associated with this first dividend. The second dividend is assumed to be received in six months, or one-half year. To be consistent with the Commission's assumptions, the model shown in equation (4) represents the dividend to be received "a half year away" as including the annual dividend increase, hence, the second term in brackets is $(1+g)(1+k)^{.5}$.

To see the difference in results between this model and the FERC model, assume that a utility currently pays a quarterly dividend of $0.25 per share, that its stock price is $10.00, and that investors expect an annual average rate of growth of five percent. Under these assumptions the FERC model estimates that investors require a rate of return of 15.83 percent while the equation (4) model indicates a required rate of return of 15.97 percent.

Elimination of Dividend Reinvestment Income

The investor required rate of return estimated using equation (4) overstates the required rate of return for

ratemaking since it includes the return that investors expect to earn during part of the year by reinvesting the dividends received in the first three quarters of the year.

In an appendix to the FERC Staff Report on Ratemaking Rate of Return that accompanied Order No. 442-A, Staff begins with the version of equation (4) which assumes that, on average, the next dividend increase is expected in nine months and the next dividend is to be received in three months. From this model Staff then proceeds to demonstrate that elimination of the dividend reinvestment portion of the return from the market required rate of return (Staff's version of equation (4)) leads to equation (1).

If, instead, we begin with the Commission's assumption that "the next dividend increase is a half year away," equation (4) describes investors' effective market required rate of return, k-mkt. The required rate of return estimated using this model includes the partial year return which investors have an opportunity to earn on their own by reinvesting the first three quarterly dividends. The portion of the effective market rate of return that is associated with dividend reinvestment is:

$$k\text{-div} = \frac{Do}{4Po} \left\{ [(1+k)^{.75} - 1] + (1+g)[(1+k)^{.5} - 1] + (1+g)[(1+k)^{.25} - 1] \right\} \quad (5)$$

Subtracting equation (5) from equation (4) yields the following required ratemaking rate of return, k-reg:

$$(k\text{-mkt}) - (k\text{-div}) = \frac{Do}{4Po} [1 + (1+g) + (1+g) + (1+g)] + g$$

$$= k\text{-reg} = \frac{Do}{Po} \left[1 + .75\, g \right] + g \qquad (6)$$

Equation (6) is the DCF model that correctly reflects the Commission's stated assumptions regarding the timing of dividends and dividend increases. For a utility with a current dividend of $0.25 per share, stock selling at $10.00 and an expected growth rate of five percent, this model indicates that the required return for ratemaking is 15.375 percent as opposed to the 15.25 percent indicated by the FERC model (equation (1)). Use of a DCF model in the form of equation (6) will result in an allowed benchmark rate of return equal to the cost of common equity capital for the typical utility under the assumptions that there are quarterly dividends, the next dividend increase is a half year away, and the next dividend is expected in three months. These are the assumptions that FERC has consistently expressed or implied in its various Orders.

An Alternative Model

Since the time that Order No. 420 was issued, FERC has reconsidered its use of the equation (1) model, but in Order Nos. 442-A, 461 and 489 the Commission decided to continue using this model. Apparently, FERC is unaware of the discrepancy between its model and the assumptions that it believes are reflected in its model. This discrepancy is particularly apparent in Order No. 461 where the Commission used a numerical example to demonstrate that its model "...attempts to approximate the average amount of dividends that the average investor (or, equivalently, investors in the average company) would expect to receive during the first

TABLE 1

ORDER NO. 461 EXAMPLE

Dividend Increased During Quarter	Dividend Received 3/31	6/30	9/30	12/31	Total
1	$0.25	$0.25	$0.25	$0.26	$1.01
2	$0.25	$0.25	$0.26	$0.26	$1.02
3	$0.25	$0.26	$0.26	$0.26	$1.03
4	$0.26	$0.26	$0.26	$0.26	$1.04
				Average	$1.025

.025/.05 = .5

.025/.04 = .625

TABLE 2

CORRECTED EXAMPLE

Dividend Increased During Quarter	Dividend Received 3/31	6/30	9/30	12/31	Total
1	$0.25	$0.25	$0.25	$0.2625	$1.0125
2	$0.25	$0.25	$0.2625	$0.2625	$1.0250
3	$0.25	$0.2625	$0.2625	$0.2625	$1.0375
4	$0.2625	$0.2625	$0.2625	$0.2625	$1.0500
				Average	$1.03125

.03125/.05 = .625

year."[5] The numerical example in the Order contained a significant mathematical error, however.

The Order No. 461 example was designed to show the average portion of the expected annual dividend growth rate that an investor would expect to receive during the first year if the annual dividend increase has an equal probability of occurring in any of the next four quarters. The example, reproduced in Table 1, assumes that the stock is purchased on January 1, the most recent quarterly dividend was $0.25 per share, and the dividend growth rate is five percent.

Although it started with the assumption that the dividend growth rate is <u>five</u> percent, the Order No. 461 example erroneously proceeded to show the average dividends that would be paid each quarter if the growth rate is <u>four</u> percent. This can be seen in Table 1 by observing that the increased dividend is $0.26 rather than the $0.2625 which would be required for a five percent growth rate.

The Order No. 461 example divided the average first year dividend increase associated with a four percent growth rate, 2.5 percent, by the five percent growth rate to conclude that the dividend yield multiplier should be [1 + .5g]. However, dividing the average dividend increase in the example by four percent--the increase actually employed in the Order No. 461 example--leads to the conclusion that the Commission's reasoning in Order No. 461 requires the dividend yield multiplier to be [1 + .625g]. The same conclusion is also reached in Table 2 which reflects a five percent annual dividend growth rate and divides the average first year dividend increase by five percent.

Order No. 461 did not provide a reasonable justification for the FERC DCF model. It was only by coincidence that the mathematical error in the example happened to lead, erroneously, to the conclusion that the FERC model correctly reflected the Commission's assumptions. By the reasoning in Order No. 461, if the mathematical error is corrected, the Commission should be using the following DCF model:

$$k = \frac{Do}{Po} \left[1 + .625\ g \right] + g \qquad (7)$$

Although the .625 growth rate factor in equation (7) is at the mid-point between the .75 factor in equation (6) and the .5 factor in the FERC model (equation (1)), equation (7) cannot be derived directly from any reasonable set of assumptions regarding the timing of dividends and dividend increases. It is clearly reasonable to assume that, on average, the next annual dividend increase is a half year away. Both equations (1) and (6) can be derived from this assumption.

On the other hand, since the next quarterly dividend, on average, will be received at the mid-point between today, as assumed in equation (1), and three months from today, as assumed in equation (6), equation (7) could be considered to be an <u>ad hoc</u> model representing a simple average of the dividend timing assumptions in the alternative models given by equations (1) and (6).

<u>Conclusions</u>

As this article points out, Order No. 442 contains a modelling error and Order No. 461 contains a mathematical error

in translating the Commission's stated reasoning into an appropriate model for establishing the generic rate of return. As a result, the FERC DCF model does not reflect a reasonable set of assumptions.

It is not posible to construct a quarterly dividend model that satisfies both the assumption that the next dividend increase is a half year (2 quarters) away and the assumption that the next dividend payment is a half quarter away. Equation (7) could be justified as an approximate adjustment to account for the average time until the next quarterly dividend payment. However, since FERC has consistently expressed the assumptions that the next dividend is a full quarter away[6] and the next dividend increase is a half year away, the only model that correctly reflects the Commission's assumptions is equation (6).

Although the difference between equation (6) and the FERC model is likely to lead to a rate of return difference of only 10-12 basis points, the total dollars involved on an industry-wide basis are quite substantial. This is particularly true if other commissions look to the FERC generic rate of return formula as the proper method. The Commission rejected the models given by equations (2) and (3) because these models did not properly reflect reasonable assumptions regarding the timing of dividends and dividend increases. After devoting a great deal of time and effort to establishing reasonable assumptions in its various generic rate of return proceedings, it would be a shame for FERC to continue to use a DCF model that, because of simple mathematical errors, fails to reflect those assumptions.

NOTES

1. FERC Order No. 420, 50 Fed. Reg. at 30,208 (May 29, 1985).

2. FERC Order No. 442-A, 51 Fed. Reg. 22,505 (June 20, 1986); FERC Order No. 461, 52 Fed. Reg. 11 (Jan. 2, 1987); FERC Order No. 489, 53 Fed. Reg. 3,342 (Feb. 5, 1988).

3. FERC Order No. 442, 51 Fed. Reg. 343 (Jan. 6, 1986) at page 19 of the original order.

4. For example, at page 22 of Order No. 442 the Commission quotes the language of Order No. 420 in stating that "...from the perspective of the average company or the average investor, the next dividend increase is a half year away." Similarly, page 23 of Order No. 442 contains the assertion that "(t)he Commission's model assumes a dividend increase occurs at mid-year for the typical utility."

5. FERC Order No. 461 (pages 17-18), quoting Order No. 420, 50 Fed. Reg. at 21,806.

6. For example, see equation (6) at page 19 of Order No. 442 and page 26 where the Commission describes its assumptions.

Montana-Dakota Utilities Co.

Revised Exhibit___(JWW-1) -- Earnings Growth Model Including Flotation Cost Adjustment

	Company	[1] Recent Dividend Yield	[2] Projected Growth Value Line	[3] Projected Growth Zacks	[4] Secondary Market D/P + g	[5] Flotation Cost Adjustment	[6] Primary Market D/P + g
GAS	AGL Resources Inc.	4.8%	6.0%	4.4%	10.0%	1.04	10.4%
ATO	Atmos Energy Corp.	4.1%	4.0%	6.0%	9.1%	1.04	9.5%
LG	Laclede Group, Inc.	4.3%	3.0%	3.0%	7.3%	1.04	7.6%
NJR	New Jersey Resources Corp.	4.0%	5.5%	4.0%	8.8%	1.04	9.1%
NWN	Northwest Natural Gas Co.	4.2%	3.0%	4.2%	7.8%	1.04	8.1%
PNY	Piedmont Natural Gas Co., Inc.	4.0%	2.5%	3.7%	7.1%	1.04	7.4%
SJI	South Jersey Industries, Inc.	3.6%	9.0%	6.0%	11.1%	1.04	11.5%
SWX	Southwest Gas Corp.	3.1%	9.0%	5.0%	10.1%	1.04	10.5%
	Average				**8.91%**		**9.26%**
	High				11.10%		11.54%
	3rd Quartile				10.03%		10.43%
	2nd Quartile (Median)				**8.93%**		**9.28%**
	1st Quartile				7.68%		7.98%
	Low				7.10%		7.38%

Notes:
[1], [2], [3] Source: Exhibit___(JWW-1)
[4] Equals [1] + Average([2], [3])
[5] Source: Exhibit No.___(JSG-2), Schedule 3
[6] Equals [4] x [5]

Montana-Dakota Utilities Co.

Revised Exhibit___(JWW-2) -- Dividend Growth Model
Including Flotation Cost Adjustment and Excluding ROEs ≤ Cost of Debt + 100 bp

	Company	[1] Recent Dividend Yield	[2] Projected Dividends Growth	[3] Secondary Market D/P + g	[4] Exclude?	[5] Flotation Cost Adjustment	[6] Primary Market D/P + g	[7] Exclude?
GAS	AGL Resources Inc.	4.8%	1.5%	6.3%		1.04	6.6%	
ATO	Atmos Energy Corp.	4.1%	1.5%	5.6%	Yes	1.04	5.8%	
LG	Laclede Group, Inc.	4.3%	2.5%	6.8%		1.04	7.1%	
NJR	New Jersey Resources Corp.	4.0%	4.0%	8.0%		1.04	8.3%	
NWN	Northwest Natural Gas Co.	4.2%	2.5%	6.7%		1.04	7.0%	
PNY	Piedmont Natural Gas Co., Inc.	4.0%	3.5%	7.5%		1.04	7.8%	
SJI	South Jersey Industries, Inc.	3.6%	9.0%	12.6%		1.04	13.1%	
SWX	Southwest Gas Corp.	3.1%	8.0%	11.1%		1.04	11.5%	
	Average			**8.08%**			**8.40%**	
	High			12.60%			13.10%	
	3rd Quartile			8.78%			9.13%	
	2nd Quartile (Median)			**7.15%**			**7.44%**	
	1st Quartile			6.60%			6.86%	
	Low			5.60%			5.82%	
	Average (excl. ROEs ≤ Cost of Debt + 100 bp)			**8.43%**			**8.40%**	
	High			12.60%			13.10%	
	3rd Quartile			9.55%			9.13%	
	2nd Quartile (Median) (excl. ROEs ≤ Cost of Debt + 100 bp)			**7.50%**			**7.44%**	
	1st Quartile			6.75%			6.86%	
	Low			6.30%			5.82%	

Notes:
[1], [2] Source: Exhibit___(JWW-2)
[3] Equals [1] + [2]
[4] Equals "Yes" if [3] ≤ Cost of Debt + 100 bp; Cost of Debt = 4.64%
[5] Source: Exhibit No.___(JSG-2), Schedule 3
[6] Equals [3] x [4]
[7] Equals "Yes" if [6] ≤ Cost of Debt + 100 bp; Cost of Debt = 4.64%

Montana-Dakota Utilities Co.

Revised Exhibit___(JWW-3) -- Book Value Growth Model
Including Flotation Cost Adjustment and Excluding ROEs ≤ Cost of Debt + 100 bp

	Company	[1] Recent Dividend Yield	[2] Projected Book Value Growth	[3] Secondary Market D/P + g	[4] Exclude?	[5] Flotation Cost Adjustment	[6] Primary Market D/P + g	[7] Exclude?
GAS	AGL Resources Inc.	4.8%	5.0%	9.8%		1.04	10.2%	
ATO	Atmos Energy Corp.	4.1%	6.0%	10.1%		1.04	10.5%	
LG	Laclede Group, Inc.	4.3%	4.5%	8.8%		1.04	9.2%	
NJR	New Jersey Resources Corp.	4.0%	5.5%	9.5%		1.04	9.9%	
NWN	Northwest Natural Gas Co.	4.2%	1.0%	5.2%	Yes	1.04	5.4%	Yes
PNY	Piedmont Natural Gas Co., Inc.	4.0%	1.5%	5.5%	Yes	1.04	5.7%	
SJI	South Jersey Industries, Inc.	3.6%	6.0%	9.6%		1.04	10.0%	
SWX	Southwest Gas Corp.	3.1%	6.0%	9.1%		1.04	9.5%	
	Average			**8.45%**			**8.79%**	
	High			10.10%			10.50%	
	3rd Quartile			9.65%			10.04%	
	2nd Quartile (Median)			**9.30%**			**9.67%**	
	1st Quartile			7.98%			8.29%	
	Low			5.20%			5.41%	
	Average (excl. ROEs ≤ Cost of Debt + 100 bp)			**9.48%**			**9.27%**	
	High			10.10%			10.50%	
	3rd Quartile			9.75%			10.09%	
	2nd Quartile (Median) (excl. ROEs ≤ Cost of Debt + 100 bp)			**9.55%**			**9.88%**	
	1st Quartile			9.20%			9.31%	
	Low			8.80%			5.72%	

Notes:
[1], [2] Source: Exhibit___(JWW-3)
[3] Equals [1] + [2]
[4] Equals "Yes" if [3] ≤ Cost of Debt + 100 bp; Cost of Debt = 4.64%
[5] Source: Exhibit No.___(JSG-2), Schedule 3
[6] Equals [3] x [5]
[7] Equals "Yes" if [6] ≤ Cost of Debt + 100 bp; Cost of Debt = 4.64%

Montana-Dakota Utilities Co.

Revised Exhibit___(JWW-4) -- Fundamental Growth Model Including Flotation Cost Adjustment

	Company	[1] Projected D/P	[2] Recent Dividend Yield	[3] Fundamental Growth	[4] Secondary Market D/P + g	[5] Flotation Cost Adjustment	[6] Primary Market D/P + g
GAS	AGL Resources Inc.	3.5%	4.8%	6.5%	11.3%	1.04	11.8%
ATO	Atmos Energy Corp.	4.2%	4.1%	3.5%	7.6%	1.04	7.9%
LG	Laclede Group, Inc.	3.8%	4.3%	4.5%	8.8%	1.04	9.2%
NJR	New Jersey Resources Corp.	3.5%	4.0%	7.5%	11.5%	1.04	12.0%
NWN	Northwest Natural Gas Co.	3.3%	4.2%	4.0%	8.2%	1.04	8.5%
PNY	Piedmont Natural Gas Co., Inc.	3.9%	4.0%	3.5%	7.5%	1.04	7.8%
SJI	South Jersey Industries, Inc.	3.7%	3.6%	7.5%	11.1%	1.04	11.5%
SWX	Southwest Gas Corp.	2.8%	3.1%	6.0%	9.1%	1.04	9.5%
	Average				**9.39%**		**9.76%**
	High				11.50%		11.96%
	3rd Quartile				11.15%		11.60%
	2nd Quartile (Median)				**8.95%**		**9.31%**
	1st Quartile				8.05%		8.37%
	Low				7.50%		7.80%

Notes:
[1], [3] Source: Exhibit___(JWW-4)
[2] Source: Exhibit___(JWW-1)
[4] Equals [2] + [3]
[5] Source: Exhibit No.___(JSG-2), Schedule 3
[6] Equals [4] x [5]

Montana-Dakota Utilities Co.

MDU Resources Group, Inc. Common Stock Offerings

Company	Ticker	Date	[1] Shares Issued (Including Over-Allotments)	[2] Offering Price	[3] Underwriting Discount	[4] Offering Expense	[5] Gross Equity Issue	[6] Total Flotation Cost	[7] Net Proceeds	[8] Flotation Cost as Percent of Net Proceeds
MDU Resources Group, Inc.	MDU	2/4/2004	2,300,000	$23.32	$0.793	$350,000	$53,636,000	$2,173,900	$51,462,100	4.2%
MDU Resources Group, Inc.	MDU	11/19/2002	2,400,000	$24.00	$0.72	$192,500	$57,600,000	$1,920,500	$55,679,500	3.4%
MDU Resources Group, Inc.	MDU	4/21/1998	2,400,000	$35.625	$0.98	$210,000	$85,500,000	$2,562,000	$82,938,000	3.1%
									Average:	**3.6%**

Notes:
[1], [2], [3], [4] Source: Form 424B5 dated 4/22/1998, 11/20/2002, 2/5/2004; includes over-allotments
[5] Equals [1] x [2]
[6] Equals ([1] x [3]) + [4]
[7] Equals [5] − [6]
[8] Equals [6] / [7]

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

Before the Public Service Commission of Montana

Docket No. D2012.9.100

Rebuttal Testimony
of
Rita A. Mulkern

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

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

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

5 A. I am the Director of Regulatory Affairs for Montana-Dakota Utilities
6 Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

7 **Q. Are you the same Rita A. Mulkern who filed direct testimony earlier in**
8 **this proceeding?**

9 A. Yes, I am.

10 **Q. What is the purpose of your rebuttal testimony?**

11 A. The purpose of my rebuttal testimony is to address certain
12 adjustments proposed by Mr. Albert E. Clark. I am also sponsoring Exhibit
13 No. ___(RAM-4).

14 **Q. On pages 6-7 of Mr. Clark's testimony, he proposes to shorten the**
15 **time period for the amortization of gains and/or losses on the sale of**
16 **plant. Do you agree with his adjustment?**

17 A. Montana-Dakota has used a five year average for many years
18 pursuant to past Commission practice, which Mr. Clark has agreed with in

1 past filings. While Mr. Clark references the correlation with the timing of
2 rate case amortization, given the large gain on the sale of plant received in
3 2011, his change to a three year amortization is this case seems results
4 driven. Given the long history of using a five year amortization, Montana-
5 Dakota believes that a five year amortization of such gains/losses on the
6 sale of plant, is appropriate and Mr. Clark's adjustment should be rejected.
7 **Q. On page 8 of his testimony, Mr. Clark makes an adjustment to**
8 **Montana-Dakota's labor expense to reflect an average of incentive**
9 **compensation, but excludes the amortization of the 2009 severance.**
10 **Do you agree with his adjustment?**
11 A. No, I do not agree with Mr. Clark's removal of the severance
12 amount from the calculation of the labor increase. The severance pay
13 was the result of the Company's integration efforts and a corresponding
14 reduction in labor expense. Since the labor savings are a long term
15 benefit, Montana-Dakota proposed to reflect the expense necessary to
16 realize the savings over a three year period. If Mr. Clark's proposal to
17 drop the 2009 severance costs is used, his adjustment should still include
18 two years of the amortization for 2010-2011.
19 Also on the adjustment to labor, Mr. Clark misstated the per books
20 labor expense for production expense, using $18,149 rather than $28,149,
21 which overstates his decrease to labor by $10,369 plus the effects on
22 workers compensation and payroll taxes. In his later adjustment to

1 remove the Billings Landfill expense, he removes the correct amount,
2 thereby overstating the reduction to labor expense.
3 The revised calculation of production labor and the inclusion of a
4 portion of the severance pay is shown on Exhibit No.___(RAM-4), page 1.
5 **Q. Mr. Clark adjusts Montana-Dakota's postage expense on page**
6 **10 of his testimony to reflect the budgeted gas utility expense for**
7 **2012. Do you agree with this?**
8 A. No, I do not, for two reasons. First, when Montana-Dakota reviews
9 the budget information for use in developing operation and maintenance
10 (O&M) expense, it looks at combined gas and electric expenses on a total
11 Company basis in order to eliminate any effects of allocations between
12 gas and electric. For example, the adjustments to benefits, which Mr.
13 Clark generally accepted, were calculated in this manner. For postage
14 expense, however, instead of looking at the combined change of a
15 decrease of 0.03 percent (which would be immaterial and supports why no
16 adjustment was made), Mr. Clark used the entire gas utility decrease of
17 $7,919 and applied it to Montana. His adjustment is not consistent, not
18 correct and should be rejected.
19 **Q. On pages 10-11 of his testimony, Mr. Clark makes an adjustment to**
20 **the Company's Board of Directors meeting expenses. Do you agree**
21 **with his adjustment?**
22 A. No. Mr. Clark made two errors in calculating his adjustment. While
23 the Commission has made such an adjustment in the past, Mr. Clark's

1 adjustment does not reflect the methodology used in the past by the
2 Commission. Previously, the adjustment recognized that the board
3 meeting held in Palm Springs, California is typically a three day meeting
4 while the other board meetings are typically 1.5 days. On a per day basis,
5 the Palm Springs meeting costs less than the other meetings and in
6 utilizing the average expense would result in an increase, not a decrease
7 to adjust the Palm Springs meeting to the average cost of the three other
8 meetings.

9 Mr. Clark also updated the board expenses to reflect the actual
10 2012 expenses, however, Mr. Clark made an error in that he assumed that
11 Montana-Dakota is allocated 100 percent of board of directors expense in
12 his calculation of the adjustment, neglecting to reflect the fact that
13 Montana-Dakota receives only a portion of the board of directors expense.
14 If his adjustment were accepted, the corrected adjustment would be an
15 increase in O&M expense of $504 as shown on Exhibit No.___(RAM-4),
16 page 2, Mr. Clark also failed to include the tax effect of his adjustment.

17 No adjustment should be made to the board of directors expense
18 included in the Company's revenue requirement.

19 **Q. Mr. Clark made an adjustment to the interest synchronization**
20 **calculation that includes the construction work in progress (CWIP)**
21 **that is not in service. Do you agree with that adjustment?**

22 A No, I do not. Mr. Clark added the non-rate base CWIP to the
23 calculation of interest. The rationale for the interest synchronization

1 adjustment is to match the interest expense with the rate base investment,
2 just as plant, expense and revenues are all matched to the test year. The
3 non-rate base CWIP is not included anywhere else in the revenue
4 requirement and including it solely for interest purposes is a mismatch.
5 The matching principle means that the plant, depreciation expense,
6 depreciation reserve, interest expense and all associated expenses are
7 tied together. Including the non-rate base CWIP only in the interest
8 calculation is a mismatch and should not be accepted.

9 **Q. Mr. Clark eliminated the rate base and expenses associated with the**
10 **Billings Landfill. Was his calculation correct?**

11 A. No. Mr. Morman addresses Mr. Clark's adjustment to remove the
12 Billings Landfill from the revenue requirement, but I will address the error
13 Mr. Clark made in the elimination of the Billings Landfill from the revenue
14 requirement. Mr. Clark stated on page 13 that he removed all investment
15 and operating expenses associated with the landfill using the information
16 provided in the Company's data request response. However, Mr. Clark
17 made two mistakes: 1) he deducted the interest twice and 2) he carried
18 the tax amount forward as a reduction in income taxes rather than an
19 increase in taxes. Mr. Clark used the amounts that the Company provided
20 in a data request response, which included all aspects of the adjustment,
21 including the effect of interest on income taxes. Mr. Clark used that tax
22 amount, but then calculated the interest effect again when calculating his
23 interest synchronization adjustment.

In addition, when the Billings Landfill O&M, depreciation and taxes other than income are eliminated, the result is an increase in taxable income and an increase in income taxes. Mr. Clark's adjustment shows a decrease, rather than an increase in income taxes. Exhibit No.___(RAM-4), page 3 shows the corrected calculation.

Q. Mr. Clark relied on the Company's response to a data request in making his adjustment. Have you found any errors in that response?

A. Yes. Upon review of Mr. Clark's adjustment, it was discovered that the accumulated deferred income tax amounts provided by the Company in that data request response were not correct. Montana-Dakota inadvertently allocated the accumulated deferred income taxes to Montana twice, thus understating the accumulated deferred income taxes and understating the rate base. Exhibit No. ___(RAM-4), page 4 reflects the corrected amounts.

Q. Mr. Clark eliminated the plant additions that were not completed as of October 31, 2012. Do you have comments on his adjustment?

A. Mr. Clark allowed the plant additions that were complete at the time of the discovery process. I have updated the plant additions on Exhibit No.___(RAM-4), pages 5-6 to include the projects completed and in service as of December 31, 2012. Mr. Gardner is addressing the customer billing system in his rebuttal testimony.

Mr. Clark also made a calculation error in that when he updated the plant additions, he made the corresponding adjustments to accumulated

1 reserve for depreciation and accumulated deferred income taxes but did
2 not adjust the depreciation expense, which would have reduced
3 depreciation expense.

4 **Q. Do you have any other comments on Mr. Clark's testimony?**

5 A. Yes. When Mr. Clark calculated his pro forma plant on Exhibit
6 No.___(AEC-4), page 14, he calculated year end 2012 plant by adding his
7 allowable 2012 plant additions to average 2011 plant to arrive at the year
8 end 2012 plant, when he should have added the plant additions to year
9 end 2011 plant, which resulted in an understatement of 2012 average
10 plant in service. Exhibit No.___(RAM-4), pages 7-8 show Mr. Clark's
11 exhibit with the error corrected.

12 **Q. Does this complete your rebuttal testimony?**

13 A. Yes, it does.

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Wage and Salary Expense

Line No.		Per Books Montana	Pro Forma Montana	MDU Pro Forma Montana	Proposed MCC Adjustment
	(A)	(B)	(C)	(D)	(E)
1	Other gas supply	$ 52,641	$ 54,585	$ 55,136	$ (551)
2	Production	**28,149**	29,189	29,483	(294)
3	Distribution	3,390,504	3,515,731	3,551,214	(35,483)
4	Customer accounting	1,055,275	1,094,251	1,105,295	(11,044)
5	Customer service	55,811	57,872	58,456	(584)
6	Sales	86,721	89,924	90,832	(908)
7	Admin & general	1,021,246	1,058,965	1,069,653	(10,688)
8	Total	$5,690,347	$5,900,518	$5,960,069	$ (59,551)

		2011 Total	Pro Forma	With Severance Amort.
9	5110	$ 40,601,222	$ 41,701,320	
10	5120	3,593,762	3,691,136	
11	5130	1,705,117		
12	5131	2,098,089		
13	5140	133,594	137,213	
14	5150	48,047	49,349	
15	5193	372,609	382,705	
16	Total	$ 48,552,440	$ 45,961,723	$ 45,961,723
	3 year average restated incentive compensation w/o severance		4,383,987	4,383,987
	Amortization of severance (2 years)			337,560
	Total		$ 50,345,710	$ 50,683,270
	Per cent change		3.693%	4.389%

Column (B), Lines 1-8: Rule 38.5.157, Statement G, Page 4 of 15
Column (C): Column (B) increased by 3.693% per lines 9 - 16
Column (D), Lines 1-8: Rule 38.5.157, Statement G, page 4 of 15
Column (E), Lines 1-8: Column (C) less Column (D)

Lines 9 - 16: Statement Work papers, page G-41

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Board of Directors Meetings Expense

Line No.		Total Cost	Per Day	Allocate to: Utility Group 34.9%	Montana-Dakota 44.6%	Gas 43.7%	Montana 24.761%
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Feb 2011 - Palm Springs	$ 64,902	21,634				
2	May 2011 - Bismarck	57,444	38,296				
3	Aug 2011 - Bismarck	54,827	36,552				
4	Nov 2011 - Bismarck	39,051	26,034				
5	Total	$ 216,225	$ 122,516				
5	Feb 2012 - Palm Springs	$ 58,603	**19,534**				
6	May 2012 - Bismarck	$ 37,719	25,146				
7	Aug 2012 - Bay Harbor	$ 58,313	38,875				
8	Nov 2012 - Denver	$ 36,775	24,517				
		$ 191,410					
9	Avg of May, Aug & Nov	$ 44,269	**$ 29,513**				
10	Daily Difference		9,979				
11	Adjustment - 3 day meeting		29,936	$10,448	$4,660	$2,036	$504

Sources and references:
Company response to Data Request No. PSC-022
Allocation per Statement Work Papers, page E-4, D&O Liability Insurance

MONTANA-DAKOTA UTILITIES, CO.
Summary of Income Statement Adjustments
Gas-Utility - Montana
Test Year Ended December 31, 2011

Line No.	(A)	Billings Landfill (B)	Corrected (C)
	Operating revenues		
1	Sales		
2	Transportation		
3	Other		
4	Total Revenues	$ -	
	Operating Expenses		
	Operation and Maintenance		
5	Cost of Gas		
6	Other O&M	(197,729)	(197,729)
7	Total O&M	$ (197,729)	$ (197,729)
8	Depreciation	(103,537)	(103,537)
9	Taxes other than income taxes	(68,176)	(68,176)
10	Current income taxes	(100,147)	145,514
11	Deferred income taxes		
12	Total Operating Expenses	$ (469,589)	$ (223,928)
13	Operating Income	$ 469,589	$ 223,928
14	Rate Base	$ (2,700,919)	$ (2,700,919)

Change in taxable income	$ 369,442
Income taxes @ 39.3875%	145,514

MONTANA-DAKOTA UTILITIES CO.
RATE BASE - BILLINGS LANDFILL
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA

	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Plant Additions	Balance @ 12/31/12	Average Balance @ 12/31/12
Total Company						
Plant in Service	$10,280,259	$10,778,167	$10,529,213	$9,452,827	$10,778,167	$10,115,497
Accumulated Reserve		353,594	176,797	236,321	353,594	294,958
Net Plant	$10,280,259	$10,424,573	$10,352,416	$9,216,506	$10,424,573	$9,820,539
Accumlated Deferred Inc. Taxes	2,661,431	3,055,135	2,858,283	94,528	3,055,135	1,574,831
Net Adjustment	$7,618,828	$7,369,438	$7,494,133	$9,121,978	$7,369,438	$8,245,708
Montana 1/						
Plant in Service	$2,972,781	$3,096,756	$3,034,769	$24,906	$3,121,662	$3,109,209
Accumulated Reserve		101,594	50,797	103,537	205,131	153,362
Net Plant	$2,972,781	$2,995,162	$2,983,972	($78,631)	$2,916,531	$2,955,847
Accumlated Deferred Inc. Taxes	769,616	877,794	823,705	5,443	883,237	880,516
Net Adjustment	$2,203,165	$2,117,368	$2,160,267	($84,074)	$2,033,294	$2,075,331
Net Adjustment in MCC-133	$2,750,228	$2,742,956	$237,380	$20,292	$2,763,248	$2,753,102
Change	($547,063)	($625,588)	$1,922,887	($104,366)	($729,954)	($677,771)

1/ Allocated to Montana on normalized sales volumes.

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Post Test Year Additions

Line No.	(A)	As Filed Montana (B)	As Revised Montana (C)	MCC Adjustment (D)
	Production			
1	Landfill gas field expansion	$ 24,906	$ 24,775	$ (131)
2	Distribution			
3	Repalce mains	$ 504,015	$ 390,401	$ (113,614)
4	Replace mains - Belfry	90,010	129,826	39,816
5	**Reinforce mains- Billings**		74,275	74,275
6	Phase 3 Loop - Glendive	55,917	0	(55,917)
7	Phase 2 Loop - Wibaux	39,142	0	(39,142)
8	4" main on Bench - Billings	22,506	0	(22,506)
9	Main Ave B East - Billings	129,305	130,189	884
10	Mains and services - Billings	31,853	-	- (31,853)
11	Mains Rimrock Rd - Billings	482,100	0	(482,100)
12	4" main extension - Billings	0	35,091	35,091
13	Meas & Reg Equipments	26,647	18,750	(7,897)
14	Service lines	969,829	701,989	(267,840)
15	Main Ave B-E services	180,002	196,319	16,317
16	Meters	395,073	567,474	172,401
17	Regulators	42,090	102,618	60,528
18	Cathodic protection	107,305	170561	63,256
19	Total distribution	$ 3,075,794	$ 2,517,493	$ (558,301)
	General			
20	Gas vehicles	$ 139,603	$ 142,210	$ 2,607
21	Minor work equipment	64,203	43,022	(21,181)
22	Gas work equipment	347,473	213,353	(134,120)
23	Communications - Billings	11,546	0	(11,546)
24	Total general	$ 562,825	$ 398,585	$ (164,240)
	Common			
25	Transpotation building roof	$ 4,947	$ 7,883	$ 2,936
26	Valves - thermo - annex	13,564	17,074	3,510
27	Backup generator - Glendive	19,077	-	(19,077)
28	Wolf Point office	4,059	4,748	689
29	Hydraulic gate - Dickensen SC	5,011	**4,505**	(506)
30	Roof - Dickenson Office	7,138	5,013	(2,125)
31	Workstations - Dickinson		7,138	7,138
32	5th floor - HR	-	887	887
33	Conference room chairs	-	2,514	2,514
34	Tandem storage units	4,027	5,026	999
35	Color copier	15,797	18,876	3,079
36	B/W copier	19,592	21,499	1,907
37	Bill printer	29,594	45,768	16,174
38	Microfilm reader/printer	-	461	461
39	Update GO lobby		2,952	
40	Workstation for land agent	-	895	895
41	HM panels for GO - 5th	-	622	622
42	Office equipment	14,964	5,729	(9,235)
43	Personal computers	30,326	28,367	(1,959)
44	50 replacement MDTs	16,340	21,074	4,734
45	Oracle Exadata platforms	10,846	139,660	128,814

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Post Test Year Additions

Line No.		As Filed Montana	As Revised Montana	MCC Adjustment
46	Vehicles	66,479	27,004	(39,475)
47	Minor work equipment	14,211	4,531	(9,680)
48	Comminication equipment	63,425	7,829	(55,596)
49	Replace mobile docks		13,021	
50	GO phone system	47,553	-	(47,553)
51	Call recor system - call center	10,821	-	(10,821)
52	Network equipment	2,217	2,411	194
53	Network & Comm equipment - AMR	3,278	735	(2,543)
54	Polycom ubits - Conference rooms	2,984	-	(2,984)
55	AMR Collectors		8,278	8,278
56	Mail inserter	-	29,463	29,463
57	CTP equipment - print shop	7,505	6,530	(975)
58	DC6345 Cut/CRSR	3,175	4,049	874
59	UPS battery	562	716	154
60	Ice maker - Wolf Point	978	1,685	707
61	Ice machine - Dickenson	347	332	(15)
62	Pressure washer - Dickenson	561	478	(83)
63	Total Common	$ 419,378	$ 447,753	$ 28,375
	Common - Intangible			
64	Mobile work force software	$ 95,402	$0	$ (95,402)
65	Field collector software	-	46,500	46,500
66	Customer Info System	4,937,603		(4,937,603)
67	ARCGIS Mobile	41,034	57,044	16,010
68	Automated testiing software		3,228	3,228
69	Automated Vehicle Loc. Software	19,900	-	(19,900)
70	Powerplan software	130,262	-	(130,262)
71	IVR - Web Direct	45,170	-	(45,170)
72	Total Common - Intangible	$ 5,269,371	$ 106,772	$ (5,162,599)
73	TOTAL	$ 9,352,274	$ 3,495,378	$ (5,856,896)

Sources and references:
Company response to Data Request No. MCC-055

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Post Test Year Additions

Line No.	(A)	Balance @ 12/31/2010 (B)	Balance @ 12/31/2011 (C)	As filed Average at 12/31/2011 (E)	Allowable Plant Additions (F)	Balance at 12/31/2012 (G)	Average Balance (H)
1	Production plant	$ 2,972,781	$ 3,096,756	$ 3,034,769	$ 24,775	**$ 3,121,531**	$ 3,109,144
2	Distribution plant	70,105,115	73,250,276	71,677,695	2,298,364	**75,548,640**	74,399,458
3	General plant	5,953,718	6,010,708	5,982,213	171,682	**6,182,390**	6,096,549
4	Intangible plant - general	56,115	55,404	55,759	0	**55,404**	55,404
5	Common plant	10,639,185	10,552,679	10,595,932	470,326.0	**11,023,005**	10,787,842
6	Intangible plant - common	2,697,442	2,821,499	2,759,471	101,572	**2,923,071**	2,872,285
7	Total gas plant in service	$ 92,424,356	$ 95,787,322	$ 94,105,839	$ 3,066,719	**$ 98,854,041**	$ 97,320,682
							$ 3,214,843

Sources and references:

Rule 38.5.123, Statement C, Pages 3 - 5, of 5
Work paper 1, attached

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustments Related to Post Test Year Additions

Line No.		Average Plant Additions to Rate Base	Average APFD Rate Base	Average ADIT Rate Base
	(A)	(B)	(C)	(D)
1	Per MDU	$ 6,357,622	$ 227,786	$ 1,344,365
2	Per MCC	**3,214,843**	**115,184**	**679,802**
3	Adjustment	$ (3,142,780)	$ (112,602)	$ (664,563)
4	Per cent allowed (Line 2/Line 1)	50.56674%		

Sources and references
Column (B): Rule 38.5.123, Statement C, page 2 of 5 and Page 12, herein.
Column (C): Company's updated response to Data Request No. MCC-057
Column (D): Company's response to Data Request No. MCC-162

PUBLIC SERVICE COMMISSION

OF THE STATE OF MONTANA

REBUTTAL TESTIMONY OF

EARL M. ROBINSON

MONTANA DAKOTA UTILITIES CO.

GAS PLANT

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I. WITNESS INTRODUCTION

Q1. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Earl M. Robinson. I am a Principal & Director of AUS Consultants. My office is located at 792 Old Highway 66, Suite 200, Tijeras, NM 87059.

Q2. Q. Are you the same Earl M. Robinson who filed direct testimony earlier in this proceeding?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut the depreciation testimony and exhibits set forth by the Montana Consumer Counsel (MCC) witness Jacob Pous. I also address assertions by him regarding the provision of data, and data interpretation, along with sponsoring Exhibit No.___(EMR-4) through Exhibit No.___(EMR-9).

III. BACKGROUND

Q4. HOW IS DEPRECIATION DEFINED?

A. Depreciation is defined in the 1996 NARUC "Public Utility Depreciation Practices" publication as follows: "Depreciation, as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected

by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities."

Q5. WHY IS DEPRECIATION IMPORTANT TO THE REVENUE REQUIREMENTS OF A UTILITY COMPANY?

A. Depreciation expense enables a company to recover in a timely manner the capital costs related to its plant in service. Appropriate depreciation rates will allow recovery of a company's investments in depreciable assets over a life that provides for full recovery of the investments, less net salvage. Furthermore, the inclusion of the appropriate level of depreciation recovery in revenue requirements serves to reduce overall costs (total of depreciation and return) to customers as opposed to a situation where an inadequate level of annual depreciation expense is currently being provided in rates. The higher level of costs to customers (depreciation and return) resulting from the use of inadequate (lower) depreciation expense is the product of a higher level of rate base being retained for longer periods of time.

Q6. WHAT IS THE GUIDING PRINCIPLE IN DEVELOPING THE ESTIMATED DEPRECIATION RATES AND EXPENSE FOR A COMPANY'S OPERATING PROPERTY?

A. The goal is to estimate depreciation parameters that will develop annual depreciation rates that when applied to the Company's plant in service investment will recover the Company's first (original cost) and end of life cost over the useful average service life of the property. That is, the total cost of

the property should be ratably recovered from the customers that have benefitted from the use (that have consumed the property) of the property in the receipt of their service. The process should incorporate the current best estimates of life and salvage so that there is no intended deferral or acceleration in the depreciation process. The end goal should be full recovery at the end of life-no more and no less. The end result should be reasonable and rational as it relates to the Company's specific operating property and general experience that the Company has been and is anticipated to achieve in the foreseeable future. While comparisons can be made to other operating companies, the depreciation rates and expense are to be used to recovery the operating property of the company being studied and therefore, should be based upon the requirements of the studied company.

IV. SUMMARY

Q7. ARE THE RESULTS OF THE DEPRECIATION STUDIES THAT YOU PERFORMED FOR MDU'S GAS AND COMMON PLANT REASONABLE AND RATIONAL AND DO THEY REFLECT THE CURRENT BEST ESTIMATES OF THE DEPRECIATION LEVEL (AS OF DECEMBER 31, 2008) REQUIRED TO APPROPRIATELY RECOVER THE COMPANY PROPERTY INVESTMENTS AND END OF LIFE COST OVER THE REMAINING LIFE OF THE PROPERTY?

A. Yes, the results of the MDU-Gas's 12-31-08 depreciation study is a modest increase of $572,793 (relative to the Company's 12-31-08 depreciable plant in

service) of annual depreciation expense or approximately 5.5 % notwithstanding the fact that the study incorporated an underlying longer life average service life and lower negative net salvage percent for the Company's largest plant investment, Mains, which comprise nearly 50 % of the Company's overall plant investment. The application of the proposed account level depreciation rates to the December 31, 2008 Gas depreciable plant in service is an annual depreciation expense amount of $10,224,058 or a composite depreciation rate of 4.06%.

Further attesting to the reasonableness of the level of proposed depreciation rates is the fact that in the intervening 4 years since the effective date of the depreciation study, the Company book depreciation reserve has declined from 58.4% of depreciable original cost as of 12-31-2008 to 52.6% of depreciable original cost as of 12-31-2012 after the implementation of the proposed depreciation rates.. This fact clearly shows that the company's proposed depreciation rates are not excessive, and if anything, lower than necessary to maintain the existing depreciation reserve level.

With regard to the results of the MDU-Common's 12-31-08 depreciation study is a significant decrease of $733,017 (relative to the Company's 12-31-08 depreciable plant in service) of annual depreciation expense of 30% of the then existing depreciation rates and expense. The proposed depreciation rates and expense were decreased for a large number of the property accounts comprising MDU's Common Plant investments. The application of the proposed account level depreciation rates to the December

31, 2008 Common Plant depreciable plant in service is an annual depreciation expense amount of $1,677,496 or a composite depreciation rate of 3.92%.

Similar to the Company's Gas Plant, the Common Plant book depreciation reserve as a percentage of original cost declined over the intervening 4 years since the effective date of the depreciation study. The Company's Common Plant book depreciation reserve has declined from 50.2% of depreciable original cost as of 12-31-2008 to 43.7% of depreciable original cost as of 12-31-2012 after the implementation of the proposed depreciation rates. Likewise, this fact clearly shows that the company's proposed depreciation rates are not excessive, and if anything, lower that necessary to maintain the existing depreciation reserve level.

Q8. ARE MR. POUS' ALTERNATIVE DEPRECIATION RATES AND EXPENSE REASONABLE AND RATIONAL?

A. Absolutely not. Mr. Pous is proposing that the Company's Gas Plant book depreciation rates and expense be lowered from the present composite depreciation rate from 4.06% to 3.15% or $2,279,808 (22%) below the Company's proposed depreciation expense. For MDU-Common Plant Mr. Pous is proposing that the Company's book depreciation rates and expense be lowered from the present composite depreciation rate from 3.91% to 3.49% or $179,584 (11%) below the Company's already proposed significant reduction to annual depreciation expense.

Mr. Pous' position is clearly unreasonable and irrational especially in light of the fact that it has been demonstrated that the Company's Gas Plant book depreciation reserve, as a percent of depreciable original cost, has declined by 10% [1-(52.6%/58.4%)] in just 4 years. Likewise, the Company's Gas Plant book depreciation reserve, as a percent of depreciable original cost, has declined by 13% [1-(43.7%/50.2%)) in just 4 years, as well.

V. REBUTTAL TESTIMONY TO JACOB POUS

Q9. WHAT IS YOUR OPINION OF MR. POUS' ADVOCACY IN THIS PROCEEDING?

Mr. Pous complains about generalizations that I purportedly use in discussions about the criteria used to estimate future net salvage for available historical data, notwithstanding that all the detailed historical data has been provided to and is available to Mr. Pous for review. Furthermore, when specific line item explanations are provided relative to specific property groups, Mr. Pous simply ignores them. He goes so far as to declare how a company should record its experienced plant retirement/removal related costs for the purpose of his review.

More egregious, Mr. Pous goes on at extensive length to chastise me for destroying information required for him (Mr. Pous) to assess the reasonableness of the of MDU's proposed depreciation rates. He further states at page 14 of his testimony "Unfortunately, Mr. Robinson claims that he destroyed the results of each of the claimed SPR analyses performed

when he elected not to retain the analyses either in paper copy or other format."

Mr. Pous statements and assertions are untrue and are specifically intended to mislead the Commission.

Contrary to Mr. Pous' assertions, the following comprehensive response to Data Request MCC-136 was provided to Mr. Pous relative to his original data request for company depreciation information:

> "Please see Response No. MCC-135 for a complete copy of the historic depreciation database. **The output of the SPR analysis is not maintained in paper copy or other format. The databases and study software are electronic and the analysis is run in real time during the course of completing the study and plot outputs are provided (in the depreciation study report) for the service life parameters that were estimated for each of the property groups. The provision of any such output information would require rerunning the numerous SPR analyses and capture the results in an output file.** The SPR and or other analysis is one additional tool of various items that are reviewed to identify the applicable service life for each of the applicable property groups.
>
> It is imperative to note that page 126 of the "NARUC 1996 Public Utility Depreciation Practices" manual specifically states that: "Depreciation analysis should avoid becoming ensnared in the mechanics of the historical life study and relying solely on mathematical solutions. The reason for making an historical life analysis is to develop a sufficient understanding of history in order to evaluate whether it is a reasonable predicator of the future."
>
> Within the SPR analysis, simulated calculations are prepared using the original gross additions along with the various curves and lives to test which life characteristics and lives best fit the range of year end balances. Such mathematical calculations are not intended to support the contention that the best fit curve is the appropriate service life parameter to be used for each of the applicable property groups.
>
> At least two reasons exist as to why it is often not appropriate to use

the mathematically best fit curve is that in many circumstances the best fit curve is often an "0" or "L" mode curve with an extremely long curve (e.g., 150 year average service life, etc.). The use of such a life and curve as the applicable future service life an account is routinely unwarranted both because the life is irrational with regard to the typical average service life experience of the account being studied, and secondly because the life characteristic (mode of curve) is not representative of what the property being studied would experience. Since property is placed into service with the expectation that its usefulness will continue for a longer length of time, with fewer retirements occurring early in the life of the property group, higher subscript and/or more right mode curves (with the exception of interim retirement curves, are routinely experienced and estimated for most property groups. Some limited quantities of property groups often are influenced by non age dependent factors such as vehicular accidents or highway projects and therefore demonstrate a lower subscript curve type, etc.

In the life analysis process, professional judgment is routinely used to select a life characteristic of the property class subsequent to which the analysis result for that characteristic is considered in the development of the estimated future average service life. That being said, life estimation process is not one of simple arithmetic calculation of historical data. While the historical retirement rate analysis and/or SPR analysis are valuable analytical tools, they are just that a tool to use and consider in the overall process. Professional judgment and experience, as well as consideration of current company factors and future events must be incorporated into the process."

Q10. DID YOU STATE THAT THE REPORTS REQUESTED BY MR. POUS COULD NOT BE REPRODUCED?

A. Clearly I did not. As can be seen from reading the above response, it is a comprehensive response to Mr. Pous' request in which I simply state that the depreciation analysis was run in real time and the output reports were not retained. I further stated: **"The provision of any such output information would require rerunning the numerous SPR analyses and capture the**

1 **results in an output file."** In my experience, there is no requirement that
2 companies must produce output reports for intervening parties, especially
3 when they have been provided with all the basic input data.

4 **Q11. DID YOU PROVIDE MR. POUS WITH SUFFICIENT RECORDS TO**
5 **ENABLE HIM TO COMPLETE HIS ASSESSMENT?**

6 A. Most definitely. As per the response included above it is noted that
7 Response No. MCC-135 provided a complete copy of the historic
8 depreciation database. All the required Company's information was provided
9 for Mr. Pous to complete whatever analysis he desired.

10 Mr. Pous submitted an affidavit stating in paragraph 14 **"a utility**
11 **presenting a depreciation request must support the request with,**
12 **among other things, the work papers it used to develop its**
13 **proposals".** Although Mr. Pous may not realize it, we are now in the
14 electronic age. **The electronic copy of the basic depreciation database**
15 **comprises the work papers.** The additional SPR outputs are simply that,
16 the output from tools used to analyze the basis work papers (electronic data
17 base). In old days of years past such work effort to analyze manual records
18 required weeks, if not months, of laborious calculations to complete. With the
19 current day use of computer models there is no need to maintain paper
20 records given the electronic records are readily available and usable with
21 limited manpower requirements. The value of the depreciation analysis

process is one of interpreting data to arrive at reasonable and rational estimates.

VI. NET SALVAGE ANALYSIS

Q12. WHAT IS MR. POUS' INITIAL COMPLAINT WITH REGARD TO YOUR NET SALVAGE ANALYSIS? DID YOU PROVIDE MR. POUS WITH SUFFICIENT RECORDS TO ENABLE HIM TO COMPLETE HIS ASSESSMENT?

A. Mr. Pous states "Mr. Robinson incorporates his estimate of future inflation into his determination of net salvage ratios to be utilized for current ratemaking purposes. Mr. Robinson employs a methodology not utilized by others in the industry in order to provide his estimated quantification of future inflation."

Mr. Pous' statement is incorrect and misleading. While a net salvage forecast is included in the salvage analysis schedules to identify the level of net salvage anticipated to occur through the end of the property group's life, that is as far as it goes. There is no automatic clerical calculation and recommendation of the forecasted net salvage amount with the proposed depreciation rate. The calculated information is included to inform and alert readers of the report about the probable future levels of net salvage. As discussed in my original direct testimony, limiting net salvage purely to history experience routinely understates the level of net salvage that will occur throughout life.

That discussion is as follows:

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

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

Assume an analysis of the experienced net salvage at year three (3). Based upon the Car #1 retirement, which was retired at a young age (2 yrs.) as compared to the average six (6) year life of the property group, the analysis indicates that the property group would generate 75% salvage. This indication is incorrect, however, because it is the result of basing the estimate on incomplete data. That is, the estimate is based upon the salvage generated from a retirement that occurred at an age which is far less than the average service life of the property group. The actual total net salvage that occurred over the average life of the assets (which experienced a six (6) year average life for the property group) is 40%, as opposed to the initial incorrect estimate of 75%.

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

Q13. DID YOU PROVIDE ANY SPECIFIC EXPLANATION TO MR. POUS REGARDING THE CRITERIA FOR SALVAGE ESTIMATION AND THE USE OF THE FORECAST NET SALVAGE AMOUNTS?

A. First, is should have be very obvious to Mr. Pous that the forecast analysis result was not the basis of the estimated future net salvage within the depreciation rates given the fact that in various cases the forecast net salvage is substantially higher than the net salvage proposal level.

Counter to Mr. Pous continual criticism about the lack of explanation my response to MCC-143 stated:

> "The net salvage forecast analysis is an additional tool used to provide information about the level of net salvage anticipated to occur relative to property over its life. The historical component of net salvage is what has transpired for only the smaller portion of the Company's property that has been retired to date. Such retirements have routinely occurred at ages far younger than the average service of the various property groups. Accordingly, the experienced historical net salvage likely significantly understates the overall net salvage that will be experienced as the property groups continue to age"
>
> "**The net salvage estimate gives consideration to the overall average, recent experience, and forecast analysis.** The estimation process is one of gradualism towards more future looking calculations which is more representative of the future net salvage that can be anticipated at end of life of the property group."

A similar response was provided in response to the PSC data request PSC-099, of which Mr. Pous would also have received a copy:

> "While historical gross salvage and cost of removal are components used in estimating future net salvage, the resulting overall historical average is often not the primary driver for the estimate."
>
> "The net salvage forecast analysis is an additional tool used to provide information about the level of net salvage anticipated to occur relative to property over its life. The historical component of net salvage is what has transpired for only the smaller portion of the Company's property that has been retired to date. Such retirements have routinely occurred at ages far younger than the average service of the various property groups. Accordingly, the experienced historical net salvage likely significantly understates the overall net salvage that will be experienced as the property groups continue to age."
>
> "**The estimated future net salvage percent for each property group gives consideration to the overall average, recent experience,** and forecast analysis. The estimation process is one of gradualism towards more future looking calculations which is more representative of the future net salvage that can be anticipated at end of life of the property group."

<u>GAS PLANT</u>

Q14. MR. POUS CONTESTED THE PROPOSED AVERAGE SERVICE LIFE FOR ONE PROPERTY ACCOUNT (NAMELY MAINS) WITHIN THE COMPANY's GAS DEPRECIAITON STUDY. WHAT ARE YOUR COMMENTS?

A. Mr. Pous' proposals and position are not unexpected. In reviewing various cases in which Mr. Pous has been engaged as an intervenor consultant, it is obvious that his general task and goal is to reduce a Company's revenue requirements, via a reduction in depreciation expense, to the greatest level

possible. Unfortunately it does not appear to be about finding the appropriate recovery level, but instead about deferring recovery as long as possible.

The issue becomes apparent when reviewing the schedule Mr. Pous' provided as an attachment to data request MDU-003, and provided as Exhibit No. ___ (EMR-4). In responding to data request MDU-003 related to Company filed versus Pous alternative depreciation and salvage parameters, in each and every case, Mr. Pous' proposal (with one rare exception) was a significant lengthening of life or lowering of negative net salvage. It is also telling that in most of the listed cases, that the adopted levels of average service life and net salvage were at the original requested level or closer to the request level as opposed to Mr. Pous' recommendations.

ACCOUNT 376 MAINS

Q15. WHAT IS MR. POUS' POSITION WITH REGARD TO MAINS

A. In lieu of the Company proposed 47-R4 year average service life and curve plus negative (-50) percent net salvage, Mr. Pous proposes a 60-R2.5 year average service life and curve plus negative (-30) percent net salvage.

Q16. WHAT WAS THE BASIS OF YOUR SERVICE LIFE ESTIMATE THE COMPANY'S MAINS ACCOUNT?

A. As noted in my data responses and Mr. Pous testimony the primary basis of life selection for the MDU Gas property and specifically Account 376 Main was the use of the Simulated Plant Record Method as well as consideration

of the current underlying average service life and results of other studies that had been performed. Initially, it is noted that the then existing depreciation rate for Account 376 Mains was based upon an underlying average service life of 45 years.

Q17. MR. POUS NOTES THAT ACTUARIAL DATA WAS AVAILABLE SO WHY DID YOU USE SPR ANALYSIS AS A PRIMARY BASIS OF YOU LIFE ESTIMATE?

A. As noted in response to Data Request MCC-177, "the Simulated Plant Record Method was the primary input for estimating the average service life parameters for Accounts 376 and 380. Through work efforts of the Company and its consultant, vintage level survivors were developed for individual sub account categories of Accounts 376 and 380 during the 2001 depreciation study. In subsequent periods, efforts have been completed to continue to develop longer range actuarial files. The Company has been and is currently in the process of implementing systems to enhance is assets record keeping capability. At the time of the completion of the 2008 study it was concluded that the use of the SPR data would be the more complete file to complete the life analysis. Since the 12-31-08 vintage sub- account files existed, they were used to calculate the December 31, 2008 average remaining lives. The estimated average service life parameters and future net salvage percent for each property group gives consideration to the overall range of data recent experience. In the completion of future depreciation studies, with the additional passage of time and additional details having been developed,

it is anticipated that the actuarial data will be used for life analysis. Inasmuch as the limited actuarial files were contained within the consultant's database, they were forwarded to the Advocate along with the SPR database files.

With regard to the service life parameters, given the nature of the utility property contained in each property group, in which quality property is placed in service with the expectation that large quantities of retirements are not anticipated shortly after being place in service, the estimated mode of survivor curve tends to be focused on more right mode (R3 or R4) or higher sub-script curves.

Q18. ON PAGE 19 OF HIS TESTIMONY MR. POUS STATES THE PRESENTATION IN YOUR DEPRECIATION STUDIES ARE INCONSISTENT BETWEEN WHAT YOU PROVIDE FOR ACTUARIAL AND SIMULATED ANALYSIS RESULTS. PLEASE PROVIDE YOUR COMMENTS.

A Mr. Pous, appears to be knowingly advancing misleading information. The presentation of curve fits in the Company's depreciation reports, between actuarial and simulated data, is not inconsistent. In each case the plot of the raw data versus the selected average service life curve is plotted. What is not presented for the SPR analysis is the Observed Life Table that is included with the actuarial study data because no such/similar report exists in the SPR process. Accordingly, the same type of reports/charts are being presented for both actuarial and simulated plant record study reports.

Q19. MR. POUS ARGUES THAT BASED UPON HIS ACTUARIAL ANALYSIS OF THE LIMITED COMPANY DATA, ALONG WITH HIS GENERALIZED STATEMENT THAT INDUSTRY LIVES THAT THE AVERAGE SERVICE LIFE SHOULD BE NO LESS THAN 60 YEARS. PLEASE PROVIDE YOUR RESPONSE.

A. On page 20 of his testimony, Mr. Pous argues that "many utilities across the country, ...have implemented bare steel replacement programs where bare steel is being removed at ages earlier than they would have obtained absent such programs." This statement is misleading, at best, as it relates to the average service life of Mains. While the programs are shortening the property categories average remaining lives, the programs "are not" driving shorter overall average service lives. Bare Steel Mains, in companies where they exist, were installed during the early part of the 20th century and, and such were contributors to longer average service life indications.

While various observations can be made to other operating company's experience, such consideration is routinely limited in scope. Conversely, Mr. Pous relies heavily on selected industry data to support his generalized statements. In his testimony, Mr. Pous referenced one of the larger entities (PSE&G), for which I recently performed a depreciation study. It is interesting to note that the PSE&G Mains average service life, including Cast Iron Mains, of which MDU has no such property, was only 44 years Exhibit No. ___(EMR-5) as compared to the 47 year average service life proposed for Account 376-Mains in the MDU Gas depreciation study report.

On page 27 of his prepared testimony, Mr. Pous states "As noted, whether viewed from the limited SPR results Mr. Robinson was prepared to provide, to limited actuarial analysis, to Mr. Robinson's own industry comparative data, or to other industry comparative data as well as recognition of the change in material and installation practices during the past several decades, an ASL no shorter than 60 years for Distribution mains should be adopted for any subaccount that Mr. Robinson proposed a 47-year ASL."

In response to Mr. Pous statement that the ASL for Mains should be no shorter than 60 year's, of 89 gas companies reporting in an earlier service life survey nearly one third of the companies reported lives in the range of 45 to 52 years with various companies reporting shorter average service life period and the remaining companies reporting longer periods. Certainly the estimated average service life of 47 for MDU Account 376 Mains is within the range of reasonableness

Even for Plastic Pipe, the evolution of materials has not and will not stop. In response to Data Request MCC-179, company management provided Mr. Pous with an explanation of the changing types of Plastic property that it has used. Mr. Pous simply chose to ignore that information.

Q20. DO YOU HAVE AN EXHIBIT CONTAINING ACCOUNT SPR ANALYSIS FIT REPORTS?

A. Yes, however as highlighted in previous testimony, one cannot simply rely on the statistical best fit of data points a listed on the analysis output. A critical factor to consider in any life analysis, and specifically with regard to SPR due

1 to the more limited amount of information considered by the method, is the
2 survival characteristic of the property group being studied. A property
3 category such as Mains is a quality high cost property that is placed into
4 service with the expectation that significant levels of retirements will not occur
5 until later in the property's life. Hence the life characteristic tends to be more
6 right mode (increase retirements occurring later in life and/or high subscript
7 curves. Accordingly, the life estimation would tend to gravitate towards R3,
8 R4 or in some circumstance to a high subscript curves such as L4, L5, S5, or
9 S6.

10 Conversely if one where to propose an O curve, or low subscript L, S, or
11 R curves it would imply a much higher level of young aged retirement and a
12 corresponding very long maximum life for the property group.

13 Exhibit No. ___(EMR-6) is various pages containing many experience
14 bands over the life of the Company's property group. Reviewing the overall
15 experience study band, the best R4 Iowa survivor curve shows an average
16 service life of 47 years. Even the best fit of the R2.5 Iowa curve proposed by
17 Mr. Pous shows an average service life of 53 years as opposed to the not
18 less than 60 year statement made by Mr. Pous.

19 **Q21. WHAT HAS OCCURRED DURING YEARS SUBSEQUENT TO 2008 (THE**
20 **EFFECTIVE DATE OF THE DEPRECIATION STUDY) WITH REGARD TO**
21 **MAINS RETIRMENTS?**

22 A. The ongoing level of retirements does have an impact on the life achieved by
23 the property group. The level of retirements has continued at higher levels

than during earlier periods. This occurrence along with increasing negative net salvage and the growth in plant has contributed to the overall decline in the depreciation reserve percent of original cost level discussed earlier in my testimony.

Q22. IS MR. POUS' RECOMMENDED NEGATIVE (-30) NET SALVGE FOR ACCOUNT 376-MAINS REASONABLE OR CORRECT?

A. No, Mr. Pous' recommended negative (-30) net salvage is not appropriate.

Initially, Mr. Pous states "My recommendation is based on an analysis of historical data recognizing patterns or trends in the data and taking into account the likely type of activity that is occurring."

He (Mr. Pous) follows up with an additional statement/argument to bolster his position by saying. " Another consideration is the fact that on systems such as the Company's, without identified main replacement programs, mains are frequently replaced due to emergency situations. The level of negative net salvage that is incurred during emergency replacement activity is normally more negative than would normally be expected in the future, as a greater quantity of mains are retired on a more planned basis."

Mr. Pous' position is preposterous. First, under emergency conditions, Mains are typically repaired and not replaced with the cost being charged to maintenance expense. Any required replacement would typically occur at a later period during normal scheduled work hours. Even on a minimal occasion, if a capital Main component was removed and replaced, any such occurrences would be de minimis.

As per my response to Data Request PSC-099, of which Mr. Pous would have received a copy, for the Company's largest account, namely, 376-Mains, the three year rolling band experience has varied but generally trended up over time. However, during the most recent four or five years through 2008, some of the yearly negative net salvage averages have been lower. Based upon the current experienced negative net salvage percent reductions, plus giving consideration that over the longer term, the negative net salvage percent will likely increase, a modest reduction was temporarily proposed for the estimated future net salvage percent.

To further validate that the expectation from the study data analysis period was appropriate, net salvage information relative to Account 376-Mains was gathered for the period 2009 through 2012 and is being provided as Exhibit No.___(EMR-7). The additional year's historical information shows that negative net salvage was in the lower range of 30 plus percent during 2009 and 2010 and then again increased to in excess of negative 50 percent during the most recent years. This additional information demonstrates that the negative net salvage is growing and that the net salvage percent of negative (-50) percent proposed by the depreciation study is reasonable and appropriate.

Mr. Pous could have chosen to request the addition year's information but simply chose not to do so.

1 **ACCOUNT 380-SERVICES**

2

3 **Q23. IS MR. POUS' RECOMMENDED NEGATIVE (-175) PERCENT NET**

4 **SALVGE FOR ACCOUNT 380-SERVICES REASONABLE OR CORRECT?**

5 A. No. As again stated in response to data request PSC-099, which Mr. Pous

6 apparent ignored, for the Company's second largest property group, Account

7 380-Services, historical net salvage through 2008 has been routinely climbing

8 above negative 200 percent net salvage.

9 To further validate that the expectation from the study data analysis

10 period was appropriate, net salvage information relative to Account 380-

11 Services was gathered for the period 2009 through 2012 and is being

12 provided as Exhibit No. ___(EMR-7). The additional year's historical

13 information shows that negative net salvage was nearly equal to or greater

14 than negative (-200) percent during all 4 subsequent years and averaged

15 approximately negative (-240) percent. This additional information

16 demonstrates that the negative net salvage continues at a high level and

17 that the net salvage percent of negative (-200) percent proposed by the

18 depreciation study is reasonable and appropriate.

19 In a discovery request (MCC-147), Mr. Pous inquired about the

20 methodology that the Company uses to allocate cost between retirement

21 and new work for projects when a service is being replaced as opposed to

22 being retired and abandoned. The Company responded by stating that it

23 creates separate work orders, one for installation and another for

24 retirement and directly charges such cost to the applicable work order.

1 Furthermore, Company management has indicated that during a
2 replacement project (either Mains or Services) almost always the facility
3 being replaced is still in service until the new replacement facility is cut
4 over into service. As such, this means that very seldom work associated
5 with the installation part of the project has any relation to or benefit to the
6 final retirement resources required to either remove or properly abandon
7 the replaced facility.

8 Mr. Pous' testimony position relative to the Company's operating
9 policy and practice is that the Company is improperly accounting for cost.
10 Based upon his position he stated: "I also recommend the Commission
11 order the Company to make a full and complete analysis of why its recorded
12 levels of negative net salvage are not only becoming more negative, but are
13 at high negative levels compared to the rest of the industry. Such analysis
14 should include a detailed review and justification of those costs directly
15 assigned to cost of removal when replacement activity occurs. It may very
16 well be a situation where activities that should be assigned to the new
17 replacement investment are being booked as cost of removal. However, in
18 no instance should the Commission adopt a more negative value than
19 currently exists."

20 To support his position to reject the proposed higher level of negative
21 net salvage for Account 380-Services, Mr. Pous, in his typical misleading
22 way, quotes the negative net salvage percent for a Gas Company which I
23 produced a study during the past five years, to argue that the MDU's net

salvage proposal is 8 times the salvage rate for other companies. The referenced negative (-25) percent net salvage that Mr. Pous quotes for RG&E is the lowest negative net salvage percent of any of the gas depreciation studies that I prepared during the past five years. There can be specific reasons for such low levels of negative net salvage such as for some companies under its jurisdiction, the NY PSC artificially caps the level of cost of removal to be recorded in the depreciation reserve.

Net salvage of the gas company studies that I performed in the past five years (other than MDU) ranged from negative (-25) to (-160) percent. It should be noted that the negative (-160) percent net salvage is not significantly less than MDU's current Account 380 net salvage percent and illustrates how wide of a range of net salvage occurs across various operating companies. Accordingly, it is irrational to believe that one can propose a net salvage rate for a company by simply selecting a net salvage percent from another study produced at the same time period. Furthermore, the quoted negative net salvage of (-25) which Mr. Pous quoted was for an operating company from back east in upstate New York with likely far different operating characteristic from MDU which is located in the western mountain states. Mr. Pous' comparison and suggested limitation is not only incorrect but also irrational.

The MDU net salvage data for Account 380 Services is clear and empirical—Mr. Pous simply choses to ignore or oppose the data when it does not serve his purpose.

1 **ACCOUNT 381-METERS**

2

3 **Q24. MR. POUS REJECTED THE COMPANY'S PROPOSED NET SALVAGE**

4 **FOR ACCOUNT 381 OF NEGATIVE (-15) PERCENT. WHY?**

5 A. Mr. Pous states in his testimony (page 41) "based on a review of the

6 Company's historical analysis of data, it would appear that the -15% proposal

7 is based on Mr. Robinson's reliance on his forecast of future inflation, which

8 results in a -19%. This future inflation escalated value of -19% and Mr.

9 Robinson's statement that he gradually tends to move to the future inflated

10 value, appears to support his -15% proposal."

11 **Q25. IS MR. POUS CORRECT?**

12 **A.** Again, absolutely not. Apparently, Mr. Pous only sees what he wants to see

13 when reviewing the complete historical net salvage data analysis schedules

14 that are contained in the depreciation study report (pages 7-29 to 7-33).

15 While page 7-33 of the depreciation study report does show the results of the

16 net salvage forecast analysis, page 7-32 in plain sight, contains the

17 calculation of the more recent year's three year rolling bands (page 7-31

18 contains earlier years three year rolling bands). For the three year rolling

19 bands for the period 1999 to 2008, the Company's historical experience with

20 regard to this property group (Account 381) has generally become more

21 negative and averaged more than negative (16) percent.

22 Likewise, as for the net salvage for the prior discussed property

23 groups, the specific basis of the net salvage estimate for this property group

24 was discussed in the response to PSC-099. As for all the other property

groups, Mr. Pous complained incessantly and stated that only generalization were provided. The specific data request response concerning net salvage for Account was: "Relative to Account 381-Meters, in recent years through 2008, the Company has routinely experienced in excess of negative 15 percent net salvage and anticipates continuing to do so."

To further validate that the expectation from the study data analysis period was appropriate, net salvage information relative to Account 381-Meters was gathered for the period 2009 through 2012 and is being provided as Exhibit No. ___(EMR-7). The additional year's historical information shows that negative net salvage averaged nearly negative (-24) percent during the period 2009 and 2012. This additional information demonstrates that the negative net salvage is growing and that the net salvage percent of negative (-15) percent proposed by the depreciation study is reasonable, appropriate, and if anything less negative that which will likely occur in the future. Again, Mr. Pous could have chosen to request the addition year's information but simply chose not to do so.

Several factors can contribute to the negative salvage for Account 381-Meters. First, the Company's customers are often spread of some distance from the Company's operating base and, as such, given that activity relative to various customer meters are spread out some potential distance, the Company experiences travel cost with the retirement/removal of property. Secondly, the Company uses Account 381-Meters to capture the cost for both Meters and Meter Installations.

The work effort relative to the retirement/removal of a meter set/installations is typically more work intensive than simply disconnecting and removing the meter from its setting.

COMMON PLANT

Q26. MR. POUS PROPOSES AN ALTERNATIVE AVERAGE SERVICE LIFE AND NET SALVAGE FOR COMMON PLANT ACCOUNT 390. WHAT GENERAL RESPONSE DO YOU HAVE?

A. Mr. Pous submitted a data request relative to the Company historical information of this account and then simply ignored the specific responses that were provided.

ACCOUNT 390 STRUCTURES & IMPROVEMENT

Q27. WITH REGARD TO AN AVERAGE SERVICE LIFE WHAT DOES MR. POUS PROPOSE?

A. Mr. Pous states in his testimony "I recommend nothing shorter than a 55-R1 life-curve combination." He further states: "These investments are steel buildings with either brick or pre-cast concrete exteriors and are owned, not leased, by the Company. Therefore, the retirement activity reflected in the actuarial results (e.g., roofs, A/C systems, etc.) relied upon by Mr. Robinson will significantly understate the life expectancy of the majority of the investment in the account (e.g., steel structures). Moreover, Mr. Robinson's actuarial analyses are inappropriately skewed to an artificially short ASL due to the inclusion of major retirements associated with transfer of the

1 corporate office building to MDU Resources Corporation 6 years after
2 completion. Office buildings, warehouses, and service centers can and do
3 last for 60 or 70 years or even longer periods."
4 While Mr. Pous got 1 or 2 items correct he is incorrect in many areas.
5 The one item that Mr. Pous did get correct was the fact that the retirement
6 amount for the Company's general office building after being in service for
7 only a few years was inadvertently included with the retirement rate analysis.
8 **Q28. IS MR. POUS' STATEMENTS AND ASSESSMENTS WITH REGARD TO**
9 **THE LIFE FOR THE COMPANY'S COMMON PLANT ACCOUNT 390**
10 **STRUCTURES AND IMPROVEMENT CORRECT?**
11 **A.** No, for a number of reasons.
12 **Q29. ARE YOU PROVIDING A CORRECTED VERISON OF THE ORIGINAL**
13 **ACCOUNT 390 LIFE ANALYSIS WHICH INCLUDED THE GENERAL**
14 **OFFICE EARLY RETIRMENT?**
15 **A.** Yes. The original inclusion of the General Office Building retirement within the
16 Account 390 retirement rate analysis has been removed and classified as an
17 outlier retirement, and then a new retirement rate analysis was run without the
18 inclusion of the general office retirement. The corrected copy of the Account
19 390 life analysis schedule and chart is identified as Exhibit No. ___(EMR-8).
20 While the general office continues to exist, there were several inter-
21 company sales due to financial considerations related to affiliate Companies,
22 etc. All of the applicable transactions for the life component and salvage
23 analysis should have excluded due to the abnormal nature of the activity.

1 The gross salvage data is currently included in Section 7 of the depreciation
2 study analysis.
3 In response to a data request from Mr. Pous, detailed explanations
4 were provide to Mr. Pous but he chose to ignore the information in his net
5 salvage recommendations (this will be further discussed with the salvage
6 information a little later in my rebuttal).
7 **Q30. WANT IS THE NEW RESULTING AVERAGE SERVICE LIFE**
8 **RECOMMENTATION AS A RESULT OF THIS ANALYSIS UPDATE?**
9 A. While the original life analysis produced an average service life indication of
10 an Iowa 35-R1 life and curve, the elimination of the General Office retirement
11 at a very young age changed the service life pattern from an R1 dispersion to
12 an R3 dispersion and also lengthened the life indication to a 37 year average
13 service life from 35 years. The R3 dispersion far more consistent of a typical
14 life pattern of a group of structures which routinely experience smaller levels
15 of component retirements earlier in life followed by more material retirements
16 of the overall structure later in life. The revised average service life, while
17 longer than the original proposal actually produces a shorter average
18 remaining life and higher proposed depreciation rate from that included in the
19 original depreciation study report. The original average remaining life listed
20 for Account 390 in the depreciation report was 25.2 years; the revised
21 average remaining life for the account is now 24.1 years. Implicitly, while the
22 change would increase the proposed depreciation expense no adjustment is
23 being proposed at this time. The cause for the shorter average remaining life

1 and higher depreciation rate is the change in the survivor characteristic from
2 the prior Iowa R1 curve to the revised R3 curve (as discussed above the
3 removal of the young aged retirements relative to the General Office building
4 caused the shift in the survival characteristic).

5 **Q31. MR POUS STATES "THE RETIREMENT ACTIVITY REFLECTED IN THE**
6 **ACTUARIAL RESULTS (E.G., ROOFS, A/C SYSTEMS, ETC.) RELIED**
7 **UPON BY MR. ROBINSON WILL SIGNIFICANLY UNDERSTATE THE LIFE**
8 **EXPECTANCY OF THE MAJORITY OF THE INVESTMENT IN THE**
9 **ACCOUNT (E.G., STEEL STRUCTURES). IS HE CORRECT?**

10 A. No. Either Mr. Pous is intentionally misstating the facts or he does not
11 understand how levels of retirements impact retirement rate analysis results.
12 A simple discussion will illustrate the impact of retirements on an observed life
13 table and resulting plotted survivor curve (the observed life table/survivor
14 curve is plotted against the Iowa curves to identify an average service life).
15 First, to the extent that only small quantities of component retirements, related
16 to roofs, A/C systems, etc. occur the indication would be that the property
17 (from a retirement perspective) would remain in service far longer than
18 otherwise. That is, for example if one had a $1,000 property with annual
19 retirements of $100, the indication is that the property would live 10 years
20 (1,000/100). Conversely, if one had a $1,000 property with annual retirements
21 of $50, the indication is that the property would live 20 years (1,000/50).
22 Therefore, with few and smaller retirements from the structure account, the
23 retirement rate analysis will generate a longer life indication, nor shorter as

1 stated by Mr. Pous. Mr. Pous' argument with regard to the historical analysis
2 of the Company's overall structure account is totally flawed.

3 **Q32. MR. POUS STATED "I RECOMMEND NOTHING SHORT THAN A 55-R1**
4 **LIFE AND CURVE COMBINATION." WHAT ARE YOUR COMMENTS?**

5 **A.** Again, Mr. Pous either has an error in his judgment and analysis or is
6 providing misleading information. His misinformed statement contains critical
7 estimation errors. In his testimony, Mr. Pous even acknowledges that a
8 portion of the portion of the buildings will not live the full life that he suggests
9 for the overall structures. In his generalized statement his estimate of
10 component cost for the build out, fit and finish of a structure at 30 percent is
11 extremely low. Finishing a building with all the mechanical, electrical,
12 interiors, HVAC, etc. is more like 50 percent or higher. These are all items
13 that are subject to far short lives. The interiors of office type structures get
14 changed out even more frequently. A reasonable range for the
15 superstructure portion of an office building would be 60 years (for 50 percent
16 of the cost) and 20 years for the finish component at 50 percent of the cost.
17 The cost of the replacement components at 20 and 40 year periods would be
18 at higher cost due to the passage of time and overall increased cost.
19 Furthermore, increased care is routinely required of construction crews when
20 reworking an occupied facility resulting in higher cost. The attached Exhibit
21 No.___(EMR-9) summarizes the resulting composite life giving consideration
22 to the applicable inputs. The result is an implicit average service life of about
23 34 plus years. The 34 year average service life result is comparable to both

the life indications from the original and revised life indications for Account 390 plus the general range of lives from industry survey results.

Mr. Pous' proposed life of 55 years for Account 390 is incorrect and irrational.

Q33. WHAT NET SALVAGE PERCENT DOES MR. POUS PROPOSE FOR ACCOUNT 390 AND WHY IS HE INCORRECT?

A. In response to Mr. Pous' data request MCC-184 the Company provided the following response explaining the basis of the gross salvage contained within Common Plant Account 390 Structures and Improvements:

> "The overwhelming majority (99 plus percent) of the $502,496 is related to the investment in the MDU Resources Group, Inc. Corporate office building that was bought and sold within a relatively short time period (6 years- bought in 1994 and sold to MDU Resources in 2001). At the time, it was decided to create a separate company under MDU Resources to hold the assets of the building and its contents. Montana-Dakota originally had on its books100 percent of the MDU Resources Corporate office building and its contents. When the new company, Future Source, was formed, Montana-Dakota sold the MDU Resources Corporate office building and its contents to Future Source at net book value."

Furthermore in response to data request PSC-099 of which Mr. Pous would have received a copy, the following response was provided:

> "While the Company has historically, on a couple of occasions, experienced positive net salvage amounts for Account 390-Structures and Improvements, the quantity of any such owned structures have been significantly reduced. Furthermore, it is anticipated that over the life of the facilities, the Company will make improvements and/or upgrades resulting in rework to the current existing facilities. Such rehabilitation, from time to time routinely results in a significant increase in the cost of removal due to the care required to remove piecemeal components as opposed to wholesale demolition and/or disposal. Even if existing properties were disposed of at the end of their useful life, any such buyer would likely be purchasing the underlying land as opposed to the outdated structure.

Hence any future gross salvage is anticipated to be exceeded by the corresponding cost of removal."

Mr. Pous simply choose to ignore both detailed responses, continued to complain about only receiving generalization, and claimed that the Company received extensive level of gross salvage. Mr. Pous' testimony is totally misleading and false. The salvage that the Company received was simply the product of internal transactions related to young aged property that in no way reflect the level of net salvage that will be received at the end of the property's life. The Company's proposal of zero net salvage for Common Plant Account 390 is the most reasonable and rational recommendation.

VII. RECOMMENDATION

Q34. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

I recommend that the proposed depreciation rates set forth in the Company's depreciation study report be uniformly and prospectively adopted by the Commission for regulatory purposes.

Q35. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Pous - D2012-9-100
ATTACHMENT MDU-003

AVERAGE SERVICE LIFE - IOWA CURVE

			376 Steel			376 Plastic			380 Steel			380 Plastic			381 Meters			390 Struct. & Imprvt.		
Company	Jurisdiction	Case No.	Utility	DUCI	Adopted	Utility	DUCI	Adopted	Utility	DUCI	Adopted	Utility	DUCI	Adopted	Utility	DUCI	Adopted	Utility	DUCI	Adopted
Southwest Gas	North Nevada	12-04005	47L2	60L1	50R2.5	47L2	60L1	50R2.5	39L3	DNA	43L2.5	39L3	DNA	43L2.5	34L1.5	DNA	34L1.5	40R3	55R3	45R3
Southwest Gas	South Nevada	12-04005	47R2.5	55R2	50R2.5	47R2.5	55R2	50R2.5	45R3	DNA	50L2	45R3	DNA	50L2	33S1	DNA	33S1	40R3	55R3	45R3
Sierra Pacific Power Co.	Nevada	10-06001	70R4	DNA	70R4	70R4	DNA	70R4	65R3	DNA	65R3	65R3	DNA	65R3	40R2	DNA	40R2	57R4	DNA	57R4
Atmos Energy	Mid-Tex	10170	70R0.5	75R0.5	70R0.5	65R2.5	70R2.5	70R2.5	37S0.5	41L1	37S0.5	37S0.5	41L1	37S0.5	37R1	35R1	37R1	45R2.5	55R2.5	45R2.5
Atmos Energy	West Texas	10041	70R1.5	78R1.5	70R1.5	70R1.5	78R1.5	70R1.5	60R3	68R2.5	60R3	60R3	68R2.5	60R3	30L1	DNA	30L1	40R2	DNA	40R2
CenterPoint	South Texas	10038	55R4	DNA	55R4	60R2.5	DNA	60R2.5	44R3	DNA	44R3	44S3	DNA	44S3	34R0.5	DNA	34R0.5	40R4	DNA	40R4
CenterPoint	East Texas	10182	64R4	DNA	64R4	60R3	DNA	60R3	49S6	DNA	49S6	40R2	DNA	40R2	33S4	DNA	33S4	55S1.5	DNA	55S1.5
CenterPoint	Houston	9902	48R3	DNA	48R3	53R3	DNA	53R3	40R2.5	DNA	40R2.5	44R2.5	DNA	44R2.5	33R0.5	DNA	33R0.5	50R3	DNA	50R3
Texas Gas Service	El Paso	9988	65R1.5	DNA	65R1.5	65R1.5	DNA	65R1.5	55R2	DNA	55R2	55R2	DNA	55R2	28R4	DNA	28R4	40R1.5	DNA	40R1.5
Southern California Gas	California	1012005	55R4	66R2.5	NA	55R4	66R2.5	NA	51L2	56S0.5	NA	51L2	56S0.5	NA	32S1	DNA	NA	20SQ	30SQ	NA
San Deago Gas & Electric	California	1012006	60S1	69R2.5	NA	60S1	69R2.5	NA	48R2.5	DNA	NA	48R2.5	DNA	NA	44L1.5	DNA	NA	26SQ	DNA	NA
ALTAGAS Utilities	Alberta	1606694	55R2	70R1.5	62.5R2	55R2	70R1.5	62.5R2	48R4	52S4	50R4	48R4	52S4	50R4	30R2.5	DNA	30R2.5	75R2	DNA	75R2
ATCO Gas	Alberta	1606822	60R3	69R2.5	66R2.5	60R3	69R2.5	66R2.5	55R3	59R2.5	57R2.5	55R3	59R2.5	57R2.5	20R0.5	DNA	20R0.5	40R2	DNA	40R2

NET SALVAGE

			376 Mains			380 Services			381 Meters			390 Struct. & Imprvt.		
Company	Jurisdiction	Case No.	Utility	DUCI	Adopted	Utility	DUCI	Adopted	Utility	DUCI	Adopted	Utility	DUCI	Adopted
Southwest Gas	North Nevada	12-04005	-10%	DNA	-10%	-35%	DNA	-35%	0%	DNA	0%	0%	DNA	0%
Southwest Gas	South Nevada	12-04005	-10%	DNA	-10%	-25%	DNA	-25%	0%	DNA	0%	0%	DNA	0%
Sierra Pacific Power Co.	Nevada	10-06001	-70%	-45%	-70%	-100%	-60%	-100%	-100%	-25%	-100%	-5%	DNA	-5%
Atmos Energy	Mid-Tex	10170	-40%	-30%	-40%	-20%	DNA	-20%	-10%	DNA	-10%	-5%	15%	-5%
Atmos Energy	West Texas	10041	-40%	DNA	-40%	-80%	-50%	-80%	-40%	DNA	-40%	0%	DNA	0%
CenterPoint	South Texas	10038	-25%	-20%		-70%	-50%		-15%	DNA	-15%	-10%	DNA	-10%
CenterPoint	East Texas	10182	-25%	DNA	-25%	-50%	DNA	-50%	0%	DNA	0%	0%	DNA	0%
CenterPoint	Houston	9902	-43%	-30%	-43%	-39%	-25%	-39%	-2%	DNA	-2%	-10%	DNA	-10%
Texas Gas Service	El Paso	9988	-20%	-5%	-20%	-30%	-15%	-30%	0%	DNA	0%	-5%	DNA	-5%
Southern California Gas	California	1012005	-55%	-40%	NA	-95%	DNA	NA	0%	DNA	NA	-25%	DNA	NA
San Deago Gas & Electric	California	1012006	-45%	DNA	NA	-75%	DNA	NA	-45%	DNA	NA	-25%	DNA	NA
ALTAGAS Utilities	Alberta	1606694	-10%	DNA	-10%	-75%	-30%	-30%	0%	DNA	0%	0%	DNA	0%
ATCO Gas	Alberta	1606822	-75%	-60%	-60%	-100%	DNA	-100%	0%	DNA	0%	0%	DNA	0%

DNA	Did not address
NA	Not available

Rebutal Exhibit EMR-2

Public Service Electric & Gas Company
Gas Division

Summary of Original Cost of Utility Plant in Service as of December 31, 2008 and Present and Proposed Parameters

			Present Parameters					Proposed Parameters						
		Original	Net Salvage				Current	Net Salvage			A.S.L./	Average		
Account		Cost	W/ COR	Gross Salv	Gross COR	Survivor	Depr	W/ COR	Gross Salv	Gross COR	Survivor	Remaining		
No.	Description	12/31/08	%	%	%	Curve	Rate	%	%	%	Curve	Life		
(a)	(b)	(c)	(d)	(e)	(f)	(g)		(i)	(j)	(k)	(in	(o)		
	Mains												**ASL**	Weight
376.11	Cast Iron	99,146,537.04	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	55-R2	25.9	**55**	5,453,059,537
376.12	Cast Iron - Bridges, Tunnels	133,153.40	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	55-R2	13.6	**55**	7,323,437
376.13	Cast Iron - Special Crossings	1,462,503.18	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	55-R2	16.7	**55**	80,437,675
376.14	Cast Iron - Special	144,878,455.28	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	55-R2	49.8	**55**	7,968,315,040
376.21	Steel	662,039,007.24	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	36-L4	22.0	**36**	23,833,404,261
376.22	Steel - Bridges, Tunnels	1,654,637.20	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	36-L4	21.5	**36**	59,566,939
376.23	Steel - Special Crossings	874,180.67	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	36-L4	5.9	**36**	31,470,504
376.24	Steel - Special	209,915.07	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	36-L4	21.5	**36**	7,556,943
376.30	Copper Inserts	4,981.14	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	30-L3	6.0	**30**	149,434
376.40	Plastic Inserts	305,045,572.40	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	39-S6	29.4	**39**	11,896,777,324
376.50	Other Inserts	1,345,853.39	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	40-L4	25.5	**40**	53,834,136
376.60	Plastic - Direct Burial	725,403,421.97	0%	0%	0%	N/A	1.61%	-75%	0%	-75%	50-R4	34.8	**50**	36,270,171,099
	TOTAL Account 376-Mains	1,942,198,217.98										28.7	**44**	85,662,066,328

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	93
Interval Between Test Points -	1
First Test Point -	1916
Last Test Point -	2008

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O3	160.63 Yrs.	7.8182E+13	28.38	35.23	43.37
O1	99.16 Yrs.	8.0322E+13	28.00	35.71	46.64
SC	99.16 Yrs.	8.0322E+13	28.00	35.71	46.64
O2	111.41 Yrs.	8.0362E+13	28.00	35.72	46.66
R0.5	83.00 Yrs.	8.7591E+13	26.82	37.29	55.77
O4	201.00 Yrs.	9.7114E+13	.00	.00	45.52
S.5	79.81 Yrs.	9.8733E+13	25.26	39.59	59.47
R1	70.16 Yrs.	1.0260E+14	24.78	40.36	71.68
L0	88.46 Yrs.	1.0546E+14	24.44	40.92	57.66
L0.5	76.94 Yrs.	1.2098E+14	22.82	43.83	66.33
R1.5	62.34 Yrs.	1.2278E+14	22.65	44.15	87.59
S0	66.78 Yrs.	1.3071E+14	21.95	45.55	75.77
L1	67.88 Yrs.	1.4533E+14	20.82	48.03	75.61
S0.5	60.97 Yrs.	1.5086E+14	20.43	48.94	86.66
R2	56.41 Yrs.	1.5126E+14	20.41	49.00	98.01
L1.5	61.91 Yrs.	1.6504E+14	19.54	51.19	83.76
R2.5	52.81 Yrs.	1.7394E+14	19.03	52.55	99.86
S1	56.28 Yrs.	1.7830E+14	18.80	53.21	95.23
L2	57.03 Yrs.	1.9458E+14	17.99	55.58	90.43
S1.5	53.41 Yrs.	1.9673E+14	17.89	55.89	98.64
R3	49.91 Yrs.	2.0308E+14	17.61	56.78	100.00
S2	50.94 Yrs.	2.2016E+14	16.91	59.12	99.91
L3	51.25 Yrs.	2.3663E+14	16.32	61.29	98.13
R4	47.16 Yrs.	2.4919E+14	15.90	62.90	100.00
S3	48.13 Yrs.	2.5250E+14	15.79	63.31	100.00
L4	47.69 Yrs.	2.7038E+14	15.26	65.52	99.99
S4	46.28 Yrs.	2.8824E+14	14.78	67.65	100.00
L5	46.06 Yrs.	3.0255E+14	14.43	69.31	100.00
R5	45.69 Yrs.	3.0452E+14	14.38	69.53	100.00
S5	45.44 Yrs.	3.1907E+14	14.05	71.17	100.00
S6	44.97 Yrs.	3.4185E+14	13.57	73.67	100.00
SQ	45.00 Yrs.	3.6682E+14	13.10	76.31	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	2004
Last Test Point -	2008

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O3	191.50 Yrs.	4.6431E+11	313.94	3.19	37.33
SC	117.66 Yrs.	4.7667E+11	309.84	3.23	39.31
O1	117.66 Yrs.	4.7667E+11	309.84	3.23	39.31
O2	132.22 Yrs.	4.7688E+11	309.77	3.23	39.32
R0.5	97.28 Yrs.	5.2014E+11	296.61	3.37	45.53
S.5	92.81 Yrs.	5.8666E+11	279.29	3.58	49.80
L0	102.88 Yrs.	6.1534E+11	272.70	3.67	49.51
R1	80.78 Yrs.	6.1744E+11	272.24	3.67	58.20
L0.5	88.44 Yrs.	7.2526E+11	251.19	3.98	57.53
R1.5	70.75 Yrs.	7.6285E+11	244.92	4.08	74.61
S0	76.28 Yrs.	7.8373E+11	241.64	4.14	64.61
L1	77.25 Yrs.	8.9644E+11	225.94	4.43	66.71
S0.5	69.00 Yrs.	9.3829E+11	220.84	4.53	75.89
R2	63.31 Yrs.	9.8262E+11	215.80	4.63	90.44
L1.5	69.81 Yrs.	1.0646E+12	207.33	4.82	75.90
S1	63.19 Yrs.	1.1568E+12	198.89	5.03	86.90
R2.5	58.84 Yrs.	1.1857E+12	196.46	5.09	97.79
L2	63.88 Yrs.	1.3172E+12	186.39	5.37	84.01
S1.5	59.63 Yrs.	1.3338E+12	185.23	5.40	93.95
R3	55.22 Yrs.	1.4920E+12	175.13	5.71	100.00
S2	56.59 Yrs.	1.5633E+12	171.09	5.84	98.40
L3	56.75 Yrs.	1.8199E+12	158.57	6.31	94.90
S3	53.00 Yrs.	2.0277E+12	150.23	6.66	99.98
R4	51.50 Yrs.	2.2926E+12	141.28	7.08	100.00
L4	52.34 Yrs.	2.4176E+12	137.58	7.27	99.83
S4	50.53 Yrs.	2.8318E+12	127.12	7.87	100.00
L5	50.25 Yrs.	3.1333E+12	120.85	8.27	100.00
SQ	49.00 Yrs.	3.1771E+12	120.02	8.33	100.00
R5	49.59 Yrs.	3.5328E+12	113.81	8.79	100.00
S5	49.34 Yrs.	3.6599E+12	111.82	8.94	100.00
S6	48.88 Yrs.	4.0700E+12	106.04	9.43	100.00
O4	201.00 Yrs.	4.9913E+13	.00	.00	45.52

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1999
Last Test Point -	2003

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O3	172.88 Yrs.	5.9937E+11	227.46	4.40	40.78
SC	106.38 Yrs.	6.1502E+11	224.55	4.45	43.48
O1	106.38 Yrs.	6.1502E+11	224.55	4.45	43.48
O2	119.53 Yrs.	6.1537E+11	224.48	4.45	43.49
R0.5	88.31 Yrs.	6.6981E+11	215.17	4.65	51.51
S.5	84.50 Yrs.	7.5964E+11	202.05	4.95	55.65
R1	73.78 Yrs.	7.8759E+11	198.43	5.04	66.69
L0	93.73 Yrs.	8.2139E+11	194.30	5.15	54.46
L0.5	80.94 Yrs.	9.3769E+11	181.85	5.50	63.10
R1.5	65.00 Yrs.	9.4951E+11	180.72	5.53	83.63
S0	69.97 Yrs.	1.0171E+12	174.61	5.73	71.80
L1	70.97 Yrs.	1.1120E+12	166.99	5.99	72.58
S0.5	63.50 Yrs.	1.1727E+12	162.62	6.15	83.27
R2	58.44 Yrs.	1.1807E+12	162.06	6.17	96.31
L1.5	64.31 Yrs.	1.2892E+12	155.09	6.45	81.37
R2.5	54.44 Yrs.	1.3750E+12	150.18	6.66	99.58
S1	58.34 Yrs.	1.3830E+12	149.74	6.68	93.02
S1.5	55.16 Yrs.	1.5523E+12	141.34	7.08	97.67
L2	58.97 Yrs.	1.5525E+12	141.33	7.08	88.68
R3	51.13 Yrs.	1.6722E+12	136.18	7.34	100.00
S2	52.41 Yrs.	1.7696E+12	132.38	7.55	99.75
L3	52.50 Yrs.	2.0435E+12	123.19	8.12	97.54
S3	49.09 Yrs.	2.2323E+12	117.86	8.48	100.00
R4	47.69 Yrs.	2.4669E+12	112.12	8.92	100.00
L4	48.47 Yrs.	2.6484E+12	108.21	9.24	99.98
S4	46.75 Yrs.	3.0380E+12	101.03	9.90	100.00
L5	46.50 Yrs.	3.3918E+12	95.62	10.46	100.00
R5	45.84 Yrs.	3.7751E+12	90.63	11.03	100.00
S5	45.66 Yrs.	3.9169E+12	88.98	11.24	100.00
S6	45.19 Yrs.	4.4369E+12	83.60	11.96	100.00
SQ	45.00 Yrs.	5.6349E+12	74.18	13.48	100.00
O4	201.00 Yrs.	1.4655E+13	.00	.00	45.52

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1994
Last Test Point -	1998

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O3	150.94 Yrs.	4.6521E+11	229.35	4.36	45.62
O1	93.13 Yrs.	4.7728E+11	226.43	4.42	49.66
SC	93.13 Yrs.	4.7728E+11	226.43	4.42	49.66
O2	104.63 Yrs.	4.7738E+11	226.40	4.42	49.67
R0.5	77.88 Yrs.	5.1494E+11	217.99	4.59	60.47
S.5	74.97 Yrs.	5.5651E+11	209.69	4.77	63.86
L0	83.27 Yrs.	5.6685E+11	207.77	4.81	61.10
R1	65.78 Yrs.	5.9169E+11	203.36	4.92	78.13
L0.5	72.41 Yrs.	6.4723E+11	194.44	5.14	70.21
S0	62.84 Yrs.	6.8269E+11	189.32	5.28	80.95
R1.5	58.50 Yrs.	6.9465E+11	187.69	5.33	92.73
L1	63.97 Yrs.	7.5847E+11	179.62	5.57	79.52
S0.5	57.38 Yrs.	7.8914E+11	176.09	5.68	91.27
R2	53.00 Yrs.	8.2836E+11	171.87	5.82	99.69
L1.5	58.25 Yrs.	8.8037E+11	166.72	6.00	87.31
S1	53.00 Yrs.	9.2767E+11	162.41	6.16	98.01
R2.5	49.56 Yrs.	9.4093E+11	161.26	6.20	100.00
O4	201.00 Yrs.	9.4770E+11	.00	.00	45.52
S1.5	50.25 Yrs.	1.0533E+12	152.42	6.56	99.69
L2	53.59 Yrs.	1.0677E+12	151.39	6.61	93.31
R3	46.66 Yrs.	1.1321E+12	147.02	6.80	100.00
S2	47.84 Yrs.	1.2198E+12	141.64	7.06	100.00
L3	47.91 Yrs.	1.4475E+12	130.02	7.69	99.30
S3	44.88 Yrs.	1.5769E+12	124.57	8.03	100.00
R4	43.56 Yrs.	1.7512E+12	118.21	8.46	100.00
L4	44.28 Yrs.	1.9331E+12	112.51	8.89	100.00
S4	42.72 Yrs.	2.2266E+12	104.83	9.54	100.00
L5	42.50 Yrs.	2.5451E+12	98.05	10.20	100.00
R5	41.88 Yrs.	2.8682E+12	92.37	10.83	100.00
S5	41.69 Yrs.	3.0098E+12	90.17	11.09	100.00
S6	41.28 Yrs.	3.5400E+12	83.14	12.03	100.00
SQ	41.00 Yrs.	4.7974E+12	71.42	14.00	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1989
Last Test Point -	1993

Curve Type	Average Service Life	Sum Of Squares Difference	Conformance Index	Index Of Variation	Ret Exp Index
O4	185.28 Yrs.	3.0449E+11	216.79	4.61	48.26
O3	133.97 Yrs.	3.0943E+11	215.05	4.65	50.09
O1	82.88 Yrs.	3.2156E+11	210.96	4.74	55.81
SC	82.88 Yrs.	3.2156E+11	210.96	4.74	55.81
O2	93.13 Yrs.	3.2171E+11	210.91	4.74	55.72
R0.5	69.75 Yrs.	3.5996E+11	199.39	5.02	69.28
S.5	67.50 Yrs.	4.1088E+11	186.63	5.36	71.69
R1	59.47 Yrs.	4.3547E+11	181.28	5.52	87.78
L0	75.18 Yrs.	4.3593E+11	181.18	5.52	67.02
L0.5	65.69 Yrs.	5.1531E+11	166.65	6.00	76.34
R1.5	53.28 Yrs.	5.2879E+11	164.51	6.08	97.78
S0	57.22 Yrs.	5.6088E+11	159.73	6.26	88.67
L1	58.28 Yrs.	6.3475E+11	150.15	6.66	85.24
R2	48.53 Yrs.	6.4945E+11	148.44	6.74	100.00
S0.5	52.44 Yrs.	6.6001E+11	147.25	6.79	96.66
R2.5	45.47 Yrs.	7.3666E+11	139.38	7.17	100.00
L1.5	53.22 Yrs.	7.4188E+11	138.89	7.20	91.86
S1	48.59 Yrs.	7.9281E+11	134.35	7.44	99.86
S1.5	46.09 Yrs.	8.8683E+11	127.03	7.87	100.00
R3	42.84 Yrs.	8.9258E+11	126.62	7.90	100.00
L2	49.06 Yrs.	9.1302E+11	125.20	7.99	96.48
S2	43.91 Yrs.	1.0165E+12	118.65	8.43	100.00
L3	43.91 Yrs.	1.2177E+12	108.41	9.22	99.91
S3	41.16 Yrs.	1.2921E+12	105.24	9.50	100.00
R4	39.94 Yrs.	1.3849E+12	101.65	9.84	100.00
L4	40.53 Yrs.	1.6240E+12	93.87	10.65	100.00
S4	39.09 Yrs.	1.8345E+12	88.32	11.32	100.00
L5	38.84 Yrs.	2.1747E+12	81.12	12.33	100.00
R5	38.28 Yrs.	2.4058E+12	77.13	12.97	100.00
S5	38.09 Yrs.	2.6011E+12	74.17	13.48	100.00
S6	37.66 Yrs.	3.2829E+12	66.02	15.15	100.00
SQ	38.00 Yrs.	3.5959E+12	63.08	15.85	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1984
Last Test Point -	1988

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
S.5	61.22 Yrs.	2.5969E+11	197.69	5.06	79.35
L0	68.07 Yrs.	2.5991E+11	197.61	5.06	72.82
R0.5	63.19 Yrs.	2.6009E+11	197.54	5.06	77.65
R1	54.16 Yrs.	2.6059E+11	197.35	5.07	94.98
O2	83.97 Yrs.	2.6171E+11	196.93	5.08	61.57
O1	74.72 Yrs.	2.6172E+11	196.92	5.08	61.90
SC	74.72 Yrs.	2.6172E+11	196.92	5.08	61.90
O3	120.63 Yrs.	2.6260E+11	196.59	5.09	54.11
O4	166.69 Yrs.	2.6300E+11	196.44	5.09	51.82
L0.5	59.66 Yrs.	2.6381E+11	196.14	5.10	82.08
R1.5	48.75 Yrs.	2.6553E+11	195.51	5.11	99.68
S0	52.13 Yrs.	2.6742E+11	194.81	5.13	95.33
L1	53.06 Yrs.	2.7528E+11	192.01	5.21	90.26
R2	44.53 Yrs.	2.7625E+11	191.68	5.22	100.00
S0.5	47.91 Yrs.	2.7841E+11	190.93	5.24	99.66
R2.5	41.78 Yrs.	2.8616E+11	188.33	5.31	100.00
L1.5	48.53 Yrs.	2.9115E+11	186.71	5.36	95.46
S1	44.47 Yrs.	2.9776E+11	184.62	5.42	100.00
R3	39.28 Yrs.	3.1099E+11	180.65	5.54	100.00
S1.5	42.22 Yrs.	3.1495E+11	179.51	5.57	100.00
L2	44.78 Yrs.	3.2336E+11	177.16	5.64	98.57
S2	40.19 Yrs.	3.4318E+11	171.97	5.81	100.00
L3	40.09 Yrs.	4.0496E+11	158.31	6.32	100.00
S3	37.59 Yrs.	4.1594E+11	156.21	6.40	100.00
R4	36.44 Yrs.	4.3463E+11	152.81	6.54	100.00
L4	36.94 Yrs.	5.3897E+11	137.22	7.29	100.00
S4	35.59 Yrs.	6.1241E+11	128.73	7.77	100.00
L5	35.31 Yrs.	7.8918E+11	113.40	8.82	100.00
R5	34.75 Yrs.	8.6417E+11	108.37	9.23	100.00
S5	34.56 Yrs.	9.9227E+11	101.13	9.89	100.00
SQ	34.00 Yrs.	1.3678E+12	86.14	11.61	100.00
S6	34.13 Yrs.	1.4705E+12	83.08	12.04	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1979
Last Test Point -	1983

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	166.59 Yrs.	1.9171E+11	185.15	5.40	51.84
O3	120.41 Yrs.	1.9399E+11	184.06	5.43	54.17
SC	74.44 Yrs.	1.9969E+11	181.41	5.51	62.13
O1	74.44 Yrs.	1.9969E+11	181.41	5.51	62.13
O2	83.66 Yrs.	1.9976E+11	181.38	5.51	61.79
R0.5	62.59 Yrs.	2.1760E+11	173.79	5.75	78.45
S.5	60.31 Yrs.	2.4137E+11	165.01	6.06	80.54
R1	53.28 Yrs.	2.5080E+11	161.88	6.18	95.95
L0	66.94 Yrs.	2.5278E+11	161.24	6.20	73.80
R1.5	47.72 Yrs.	2.8801E+11	151.06	6.62	99.87
L0.5	58.28 Yrs.	2.9075E+11	150.35	6.65	83.40
S0	50.81 Yrs.	3.0983E+11	145.64	6.87	96.83
R2	43.38 Yrs.	3.2699E+11	141.77	7.05	100.00
R2.5	40.66 Yrs.	3.2924E+11	141.28	7.08	100.00
R3	38.13 Yrs.	3.3689E+11	139.67	7.16	100.00
S0.5	46.50 Yrs.	3.5170E+11	136.70	7.32	99.99
L1	51.47 Yrs.	3.5379E+11	136.29	7.34	91.69
R4	35.03 Yrs.	3.6061E+11	135.00	7.41	100.00
L1.5	46.91 Yrs.	3.8776E+11	130.19	7.68	96.49
S1	42.94 Yrs.	4.0746E+11	127.00	7.87	100.00
S1.5	40.72 Yrs.	4.2503E+11	124.35	8.04	100.00
L2	43.06 Yrs.	4.5447E+11	120.25	8.32	99.13
S2	38.66 Yrs.	4.5480E+11	120.21	8.32	100.00
S3	35.97 Yrs.	4.8635E+11	116.24	8.60	100.00
L3	38.28 Yrs.	5.3510E+11	110.82	9.02	100.00
L4	35.09 Yrs.	5.8326E+11	106.15	9.42	100.00
S4	33.75 Yrs.	6.1788E+11	103.13	9.70	100.00
R5	32.75 Yrs.	7.1756E+11	95.70	10.45	100.00
L5	33.25 Yrs.	8.0653E+11	90.27	11.08	100.00
S5	32.41 Yrs.	9.7266E+11	82.20	12.17	100.00
S6	31.69 Yrs.	1.5937E+12	64.22	15.57	100.00
SQ	32.00 Yrs.	4.2048E+12	39.53	25.29	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1974
Last Test Point -	1978

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	140.63 Yrs.	1.5262E+11	163.06	6.13	57.46
O3	101.84 Yrs.	1.5462E+11	162.00	6.17	60.60
SC	63.25 Yrs.	1.5985E+11	159.33	6.28	73.12
O1	63.25 Yrs.	1.5985E+11	159.33	6.28	73.12
O2	71.09 Yrs.	1.5992E+11	159.29	6.28	71.40
R0.5	53.78 Yrs.	1.7525E+11	152.17	6.57	90.70
R4	31.38 Yrs.	1.7826E+11	150.88	6.63	100.00
S.5	52.03 Yrs.	1.9719E+11	143.45	6.97	92.17
R1	46.41 Yrs.	2.0061E+11	142.22	7.03	99.99
R3	34.13 Yrs.	2.0669E+11	140.12	7.14	100.00
L0	57.60 Yrs.	2.1589E+11	137.10	7.29	82.19
R2.5	36.31 Yrs.	2.2126E+11	135.43	7.38	100.00
R1.5	42.06 Yrs.	2.2176E+11	135.27	7.39	100.00
R2	38.56 Yrs.	2.3718E+11	130.80	7.65	100.00
L0.5	50.59 Yrs.	2.3947E+11	130.17	7.68	90.51
S0	44.38 Yrs.	2.5785E+11	125.45	7.97	100.00
S0.5	40.91 Yrs.	2.7752E+11	120.92	8.27	100.00
L1	44.97 Yrs.	2.7894E+11	120.61	8.29	96.60
S3	32.06 Yrs.	2.8413E+11	119.51	8.37	100.00
L1.5	41.25 Yrs.	2.9262E+11	117.76	8.49	99.02
S1.5	36.16 Yrs.	2.9536E+11	117.21	8.53	100.00
S2	34.41 Yrs.	2.9575E+11	117.14	8.54	100.00
S1	38.00 Yrs.	3.0121E+11	116.07	8.62	100.00
L4	31.22 Yrs.	3.1075E+11	114.27	8.75	100.00
S4	30.00 Yrs.	3.1929E+11	112.74	8.87	100.00
R5	29.06 Yrs.	3.2615E+11	111.54	8.97	100.00
L2	38.00 Yrs.	3.2825E+11	111.19	8.99	99.92
L3	33.97 Yrs.	3.4155E+11	109.00	9.17	100.00
L5	29.47 Yrs.	4.0160E+11	100.52	9.95	100.00
S5	28.66 Yrs.	4.9164E+11	90.85	11.01	100.00
S6	27.94 Yrs.	8.1216E+11	70.69	14.15	100.00
SQ	28.00 Yrs.	1.5826E+12	50.64	19.75	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1969
Last Test Point -	1973

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
R4	28.75 Yrs.	1.3310E+10	446.72	2.24	100.00
S4	27.13 Yrs.	2.2779E+10	341.47	2.93	100.00
L4	28.22 Yrs.	2.4949E+10	326.29	3.06	100.00
R5	26.28 Yrs.	2.4987E+10	326.04	3.07	100.00
L5	26.50 Yrs.	2.6575E+10	316.14	3.16	100.00
R3	31.03 Yrs.	2.9245E+10	301.37	3.32	100.00
S3	29.00 Yrs.	3.3639E+10	281.00	3.56	100.00
S5	25.59 Yrs.	3.6009E+10	271.59	3.68	100.00
R2.5	32.78 Yrs.	4.2904E+10	248.81	4.02	100.00
SQ	24.00 Yrs.	4.8201E+10	234.74	4.26	100.00
O4	118.31 Yrs.	5.4107E+10	221.56	4.51	62.89
S2	30.97 Yrs.	5.4136E+10	221.50	4.51	100.00
O3	85.91 Yrs.	5.4651E+10	220.46	4.54	66.91
O2	60.38 Yrs.	5.6448E+10	216.92	4.61	80.15
O1	53.72 Yrs.	5.6482E+10	216.85	4.61	86.10
SC	53.72 Yrs.	5.6482E+10	216.85	4.61	86.10
L3	30.44 Yrs.	5.6487E+10	216.84	4.61	100.00
R2	34.56 Yrs.	5.7544E+10	214.84	4.65	100.00
S6	24.63 Yrs.	5.8183E+10	213.66	4.68	100.00
R0.5	46.31 Yrs.	6.0333E+10	209.82	4.77	100.00
S1.5	32.44 Yrs.	6.2167E+10	206.70	4.84	100.00
S.5	45.00 Yrs.	6.2592E+10	206.00	4.85	100.00
L0	49.71 Yrs.	6.3212E+10	204.99	4.88	89.35
R1.5	37.31 Yrs.	6.3987E+10	203.74	4.91	100.00
R1	40.66 Yrs.	6.4439E+10	203.02	4.93	100.00
L0.5	44.06 Yrs.	6.8330E+10	197.16	5.07	95.54
S0	38.97 Yrs.	7.0303E+10	194.37	5.14	100.00
S0.5	36.25 Yrs.	7.1660E+10	192.52	5.19	100.00
S1	33.91 Yrs.	7.2099E+10	191.94	5.21	100.00
L1.5	36.50 Yrs.	7.3747E+10	189.78	5.27	99.85
L2	33.81 Yrs.	7.5822E+10	187.16	5.34	100.00
L1	39.50 Yrs.	7.7990E+10	184.55	5.42	99.09

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1964
Last Test Point -	1968

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
O4	114.47 Yrs.	2.2421E+09	784.21	1.28	63.88
O3	83.13 Yrs.	2.2595E+09	781.18	1.28	68.08
O2	58.38 Yrs.	2.3214E+09	770.69	1.30	81.70
SC	51.94 Yrs.	2.3222E+09	770.55	1.30	89.05
O1	51.94 Yrs.	2.3222E+09	770.55	1.30	89.05
R2.5	32.38 Yrs.	2.5391E+09	736.91	1.36	100.00
R0.5	44.75 Yrs.	2.5567E+09	734.36	1.36	100.00
R2	33.75 Yrs.	2.7315E+09	710.48	1.41	100.00
S.5	43.44 Yrs.	2.8569E+09	694.72	1.44	100.00
R1	39.34 Yrs.	2.9731E+09	681.01	1.47	100.00
L1.5	35.41 Yrs.	3.0353E+09	673.99	1.48	99.92
S1.5	31.78 Yrs.	3.0768E+09	669.43	1.49	100.00
R1.5	36.22 Yrs.	3.0778E+09	669.32	1.49	100.00
S1	32.94 Yrs.	3.2240E+09	653.96	1.53	100.00
L0	47.84 Yrs.	3.3595E+09	640.65	1.56	90.96
L0.5	42.47 Yrs.	3.3624E+09	640.37	1.56	96.52
S0.5	35.06 Yrs.	3.6441E+09	615.12	1.63	100.00
L1	38.03 Yrs.	3.6725E+09	612.74	1.63	99.47
L2	32.97 Yrs.	3.8691E+09	596.96	1.68	100.00
S0	37.56 Yrs.	4.0334E+09	584.68	1.71	100.00
R3	31.06 Yrs.	4.6688E+09	543.44	1.84	100.00
S2	30.63 Yrs.	5.3202E+09	509.08	1.96	100.00
L3	30.50 Yrs.	1.4343E+10	310.05	3.23	100.00
R4	29.78 Yrs.	1.7227E+10	282.91	3.53	100.00
S3	29.59 Yrs.	2.0151E+10	261.58	3.82	100.00
S6	29.78 Yrs.	2.2988E+10	244.91	4.08	100.00
L4	29.53 Yrs.	2.8616E+10	219.51	4.56	100.00
R5	29.47 Yrs.	3.6228E+10	195.09	5.13	100.00
S5	29.59 Yrs.	3.8496E+10	189.26	5.28	100.00
L5	29.44 Yrs.	4.3215E+10	178.62	5.60	100.00
S4	29.31 Yrs.	4.3949E+10	177.13	5.65	100.00
SQ	23.00 Yrs.	1.9498E+12	26.59	37.60	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1959
Last Test Point -	1963

Curve Type	*Average Service Life*	*Sum Of Squares Difference*	*Conformance Index*	*Index Of Variation*	*Ret Exp Index*
R2.5	34.94 Yrs.	1.6551E+10	215.23	4.65	100.00
S6	32.56 Yrs.	1.6602E+10	214.90	4.65	100.00
S5	32.66 Yrs.	1.6800E+10	213.63	4.68	100.00
R2	36.47 Yrs.	1.7064E+10	211.98	4.72	100.00
R1.5	39.50 Yrs.	1.7186E+10	211.22	4.73	100.00
R3	33.72 Yrs.	1.7744E+10	207.87	4.81	100.00
R5	32.69 Yrs.	1.8044E+10	206.13	4.85	100.00
R1	43.63 Yrs.	1.8111E+10	205.75	4.86	100.00
R0.5	50.88 Yrs.	1.9034E+10	200.70	4.98	94.52
L5	32.84 Yrs.	1.9319E+10	199.22	5.02	100.00
O2	67.75 Yrs.	1.9606E+10	197.76	5.06	74.15
O1	60.31 Yrs.	1.9606E+10	197.75	5.06	76.68
SC	60.31 Yrs.	1.9606E+10	197.75	5.06	76.68
R4	32.91 Yrs.	1.9631E+10	197.63	5.06	100.00
S4	32.84 Yrs.	1.9661E+10	197.48	5.06	100.00
O3	97.41 Yrs.	1.9835E+10	196.61	5.09	62.28
O4	134.63 Yrs.	1.9894E+10	196.32	5.09	58.87
S.5	49.00 Yrs.	1.9999E+10	195.80	5.11	96.49
L0	53.89 Yrs.	2.0645E+10	192.71	5.19	85.60
S0	41.38 Yrs.	2.1080E+10	190.72	5.24	100.00
S0.5	38.41 Yrs.	2.2450E+10	184.81	5.41	100.00
L0.5	47.50 Yrs.	2.2703E+10	183.77	5.44	93.07
S1	36.00 Yrs.	2.5249E+10	174.26	5.74	100.00
S1.5	34.84 Yrs.	2.6450E+10	170.26	5.87	100.00
L4	33.22 Yrs.	2.6515E+10	170.05	5.88	100.00
L1	42.31 Yrs.	2.6700E+10	169.46	5.90	98.03
S3	33.16 Yrs.	2.6865E+10	168.94	5.92	100.00
L1.5	39.44 Yrs.	2.8110E+10	165.16	6.05	99.46
S2	33.88 Yrs.	2.9137E+10	162.22	6.16	100.00
L3	34.59 Yrs.	3.2388E+10	153.86	6.50	100.00
L2	37.06 Yrs.	3.3097E+10	152.21	6.57	99.96
SQ	18.00 Yrs.	1.2772E+13	7.75	129.06	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1954
Last Test Point -	1958

Curve Type	Average Service Life	Sum Of Squares Difference	Conformance Index	Index Of Variation	Ret Exp Index
R2.5	36.34 Yrs.	7.1717E+08	699.50	1.43	100.00
R2	38.53 Yrs.	7.2687E+08	694.82	1.44	100.00
S2	35.81 Yrs.	8.4078E+08	646.04	1.55	100.00
R1.5	42.41 Yrs.	8.4320E+08	645.11	1.55	100.00
L3	36.47 Yrs.	8.7862E+08	631.97	1.58	100.00
R1	47.84 Yrs.	9.9074E+08	595.14	1.68	99.70
R0.5	57.09 Yrs.	1.0591E+09	575.61	1.74	86.11
O1	68.69 Yrs.	1.0771E+09	570.77	1.75	67.33
SC	68.69 Yrs.	1.0771E+09	570.77	1.75	67.33
O2	77.19 Yrs.	1.0780E+09	570.53	1.75	66.55
S1.5	37.19 Yrs.	1.0797E+09	570.08	1.75	100.00
O3	111.59 Yrs.	1.0916E+09	566.98	1.76	57.10
O4	154.63 Yrs.	1.0957E+09	565.91	1.77	54.34
R3	34.75 Yrs.	1.1174E+09	560.39	1.78	100.00
S.5	54.75 Yrs.	1.2745E+09	524.72	1.91	88.24
L2	40.06 Yrs.	1.3085E+09	517.85	1.93	99.74
S1	38.84 Yrs.	1.6612E+09	459.60	2.18	100.00
L0	60.41 Yrs.	1.6713E+09	458.22	2.18	79.61
S0.5	41.75 Yrs.	1.6738E+09	457.87	2.18	100.00
L1.5	43.03 Yrs.	1.6808E+09	456.93	2.19	98.41
L0.5	52.84 Yrs.	1.7545E+09	447.23	2.24	88.51
S3	34.28 Yrs.	1.7935E+09	442.33	2.26	100.00
S0	45.47 Yrs.	1.8105E+09	440.25	2.27	100.00
L1	46.97 Yrs.	2.2186E+09	397.71	2.51	95.28
L4	34.19 Yrs.	2.8138E+09	353.14	2.83	100.00
R4	33.47 Yrs.	4.1107E+09	292.17	3.42	100.00
S4	33.25 Yrs.	5.8387E+09	245.15	4.08	100.00
L5	33.25 Yrs.	6.4771E+09	232.76	4.30	100.00
R5	32.88 Yrs.	9.5257E+09	191.93	5.21	100.00
S5	32.84 Yrs.	9.7306E+09	189.90	5.27	100.00
S6	32.69 Yrs.	1.1182E+10	177.15	5.65	100.00
SQ	33.00 Yrs.	2.0199E+10	131.81	7.59	100.00

Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Simulated Plant Record Analysis Calculated As Of 12/31/2008

Simulated Balances Method

No. Of Test Points -	5
Interval Between Test Points -	1
First Test Point -	1949
Last Test Point -	1953

Curve Type	Average Service Life	Sum Of Squares Difference	Conformance Index	Index Of Variation	Ret Exp Index
S6	31.84 Yrs.	1.3226E+08	954.90	1.05	100.00
S5	32.22 Yrs.	1.3477E+09	299.14	3.34	100.00
R5	32.34 Yrs.	2.3339E+09	227.32	4.40	100.00
L5	32.97 Yrs.	3.2562E+09	192.45	5.20	100.00
S4	33.19 Yrs.	5.6641E+09	145.92	6.85	100.00
SQ	32.00 Yrs.	5.8955E+09	143.03	6.99	100.00
L4	34.63 Yrs.	8.6831E+09	117.85	8.49	100.00
R4	33.81 Yrs.	1.0738E+10	105.98	9.44	100.00
S3	35.28 Yrs.	1.3049E+10	96.14	10.40	100.00
L3	38.38 Yrs.	1.6541E+10	85.39	11.71	100.00
S2	38.44 Yrs.	2.0745E+10	76.25	13.12	100.00
R3	36.75 Yrs.	2.1262E+10	75.31	13.28	100.00
L2	44.47 Yrs.	2.5340E+10	68.99	14.50	98.69
S1.5	41.09 Yrs.	2.5676E+10	68.53	14.59	100.00
R2.5	39.81 Yrs.	2.6855E+10	67.01	14.92	100.00
S1	44.44 Yrs.	2.9635E+10	63.79	15.68	100.00
L1.5	49.59 Yrs.	3.0005E+10	63.40	15.77	94.71
R2	44.06 Yrs.	3.0971E+10	62.40	16.03	100.00
L1	56.28 Yrs.	3.2781E+10	60.65	16.49	87.21
S0.5	49.56 Yrs.	3.3693E+10	59.83	16.71	98.87
R1.5	51.25 Yrs.	3.4301E+10	59.30	16.86	98.90
L0.5	65.91 Yrs.	3.6136E+10	57.77	17.31	76.13
R1	61.13 Yrs.	3.6185E+10	57.73	17.32	85.27
S0	56.25 Yrs.	3.6659E+10	57.36	17.43	89.99
S.5	71.41 Yrs.	3.6957E+10	57.12	17.51	67.43
R0.5	76.53 Yrs.	3.6990E+10	57.10	17.51	61.80
O1	94.53 Yrs.	3.7302E+10	56.86	17.59	48.93
SC	94.53 Yrs.	3.7302E+10	56.86	17.59	48.93
O2	106.19 Yrs.	3.7307E+10	56.86	17.59	48.94
O3	154.88 Yrs.	3.7411E+10	56.78	17.61	44.68
L0	78.81 Yrs.	3.8415E+10	56.03	17.85	64.27
O4	201.00 Yrs.	4.0812E+10	.00	.00	45.52

Montana-Dakota Utilities-Gas
Summary of Net Salvage for Selected Accounts
For Years 2009-2012

Gas Plant

Account 376-Mains

Year	Orig Cost Retirement	Gross Salvage	% of Retirement	Cost of Removal	% of Retirement	Net Salvage	% of Retirement
2009	230,893	2,250	0.97%	74,552	32.29%	-72,302	-31.31%
2010	303,711	0	0.00%	101,644	33.47%	-101,644	-33.47%
2011	339,446	287	0.08%	201,494	59.36%	-201,207	-59.28%
2012	219,226	0	0.00%	120,281	54.87%	-120,281	-54.87%
Total	**1,093,276**	**2,537**	**0.23%**	**497,971**	**45.55%**	**-495,434**	**-45.32%**

Account 380-Services

Year	Orig Cost Retirement	Gross Salvage	% of Retirement	Cost of Removal	% of Retirement	Net Salvage	% of Retirement
2009	110,511	336	0.30%	345,197	312.36%	-344,861	-312.06%
2010	166,404	134	0.08%	422,812	254.09%	-422,678	-254.01%
2011	187,230	0	0.00%	358,576	191.52%	-358,576	-191.52%
2012	173,017	0	0.00%	398,268	230.19%	-398,268	-230.19%
Total	**637,162**	**470**	**0.07%**	**1,524,853**	**239.32%**	**-1,524,383**	**-239.25%**

Account 381-Meters

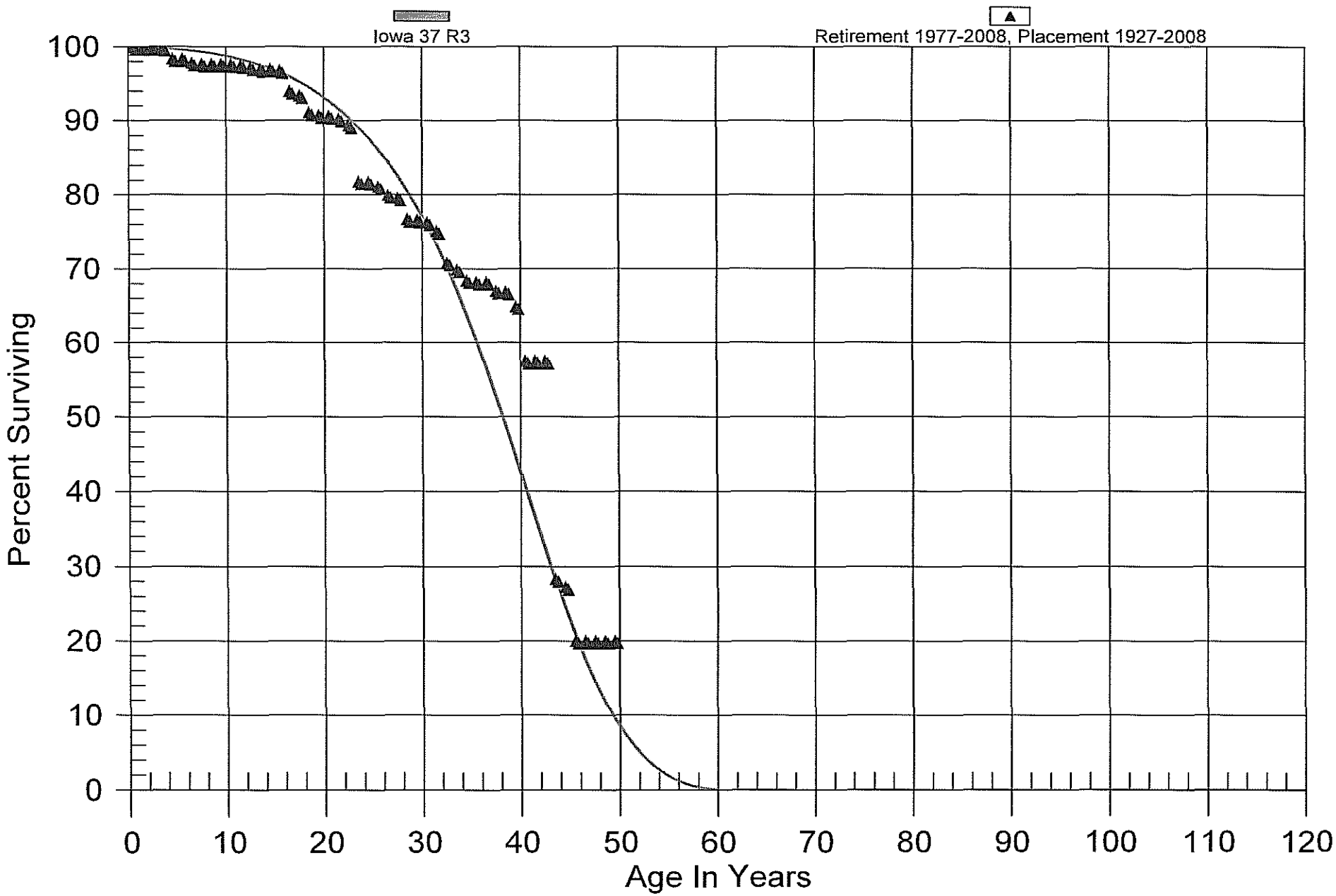
Year	Orig Cost Retirement	Gross Salvage	% of Retirement	Cost of Removal	% of Retirement	Net Salvage	% of Retirement
2009	2,454,871	10,242	0.42%	651,948	26.56%	-641,706	-26.14%
2010	218,164	8,228	3.77%	34,716	15.91%	-26,488	-12.14%
2011	439,009	25,672	5.85%	167,032	38.05%	-141,360	-32.20%
2012	482,546	15,026	3.11%	60,816	12.60%	-45,790	-9.49%
Total	**3,594,590**	**59,168**	**1.65%**	**914,512**	**25.44%**	**-855,344**	**-23.80%**

Montana-Dakota Utilities Company

Common Plant

390.00 STRUCTURES & IMPROVEMENTS

Original And Smooth Survivor Curves



Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS

Observed Life Table

Retirement Expr. 1977 TO 2008
Placement Years 1927 TO 2008

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$27,620,863.66	$25,673.53	0.00093	100.00
0.5 - 1.5	$27,344,478.47	$0.00	0.00000	99.91
1.5 - 2.5	$22,640,997.26	$11,189.66	0.00049	99.91
2.5 - 3.5	$22,245,650.64	$21,067.24	0.00095	99.86
3.5 - 4.5	$18,775,231.84	$266,416.20	0.01419	99.76
4.5 - 5.5	$17,682,758.95	$3,328.20	0.00019	98.35
5.5 - 6.5	$17,437,927.67	$101,523.45	0.00582	98.33
6.5 - 7.5	$16,912,525.05	$18,173.85	0.00107	97.76
7.5 - 8.5	$16,707,188.43	$1,185.30	0.00007	97.65
8.5 - 9.5	$17,175,374.34	$201.39	0.00001	97.64
9.5 - 10.5	$17,190,014.78	$6,909.72	0.00040	97.64
10.5 - 11.5	$17,087,646.97	$22,460.50	0.00131	97.60
11.5 - 12.5	$16,449,372.68	$54,345.65	0.00330	97.48
12.5 - 13.5	$16,094,049.40	$35,258.34	0.00219	97.15
13.5 - 14.5	$14,825,001.39	$5,991.04	0.00040	96.94
14.5 - 15.5	$12,535,830.93	$23,427.31	0.00187	96.90
15.5 - 16.5	$12,213,329.10	$347,724.14	0.02847	96.72
16.5 - 17.5	$11,709,677.50	$76,946.11	0.00657	93.97
17.5 - 18.5	$11,563,442.33	$280,138.65	0.02423	93.35
18.5 - 19.5	$11,284,647.27	$49,274.84	0.00437	91.09
19.5 - 20.5	$11,221,468.22	$13,310.98	0.00119	90.69
20.5 - 21.5	$11,316,923.39	$45,061.83	0.00398	90.58
21.5 - 22.5	$11,648,884.15	$107,434.88	0.00922	90.22
22.5 - 23.5	$11,083,154.10	$941,681.64	0.08497	89.39
23.5 - 24.5	$9,634,763.28	$6,423.19	0.00067	81.79
24.5 - 25.5	$6,635,781.46	$51,633.39	0.00778	81.74
25.5 - 26.5	$6,090,655.43	$87,706.60	0.01440	81.10
26.5 - 27.5	$4,270,597.43	$20,932.77	0.00490	79.94
27.5 - 28.5	$4,063,964.67	$146,903.96	0.03615	79.54
28.5 - 29.5	$3,674,970.31	$3,871.72	0.00105	76.67
29.5 - 30.5	$3,152,344.74	$15,451.43	0.00490	76.59
30.5 - 31.5	$3,151,652.41	$48,328.18	0.01533	76.21
31.5 - 32.5	$2,803,070.86	$158,564.05	0.05657	75.04
32.5 - 33.5	$2,602,897.43	$33,240.37	0.01277	70.80
33.5 - 34.5	$2,604,500.26	$55,135.57	0.02117	69.90
34.5 - 35.5	$2,532,951.30	$7,220.80	0.00285	68.42
35.5 - 36.5	$2,438,990.71	$0.00	0.00000	68.22

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS

Observed Life Table

Retirement Expr. 1977 TO 2008
Placement Years 1927 TO 2008

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
36.5 - 37.5	$2,015,672.80	$35,668.14	0.01770	68.22
37.5 - 38.5	$1,961,785.03	$4,062.20	0.00207	67.01
38.5 - 39.5	$1,951,978.24	$58,309.83	0.02987	66.87
39.5 - 40.5	$1,852,190.63	$209,702.82	0.11322	64.88
40.5 - 41.5	$633,016.01	$0.00	0.00000	57.53
41.5 - 42.5	$471,963.84	$0.00	0.00000	57.53
42.5 - 43.5	$319,624.00	$162,495.28	0.50840	57.53
43.5 - 44.5	$153,278.41	$5,769.46	0.03764	28.28
44.5 - 45.5	$128,525.01	$33,976.68	0.26436	27.22
45.5 - 46.5	$89,090.20	$0.00	0.00000	20.02
46.5 - 47.5	$79,478.26	$0.00	0.00000	20.02
47.5 - 48.5	$78,245.67	$0.00	0.00000	20.02
48.5 - 49.5	$76,167.37	$0.00	0.00000	20.02
49.5 - 50.5	$377,333.98	$0.00	0.00000	20.02
50.5 - 51.5	$375,995.96	$3,171.15	0.00843	20.02
51.5 - 52.5	$361,606.23	$0.00	0.00000	19.85
52.5 - 53.5	$337,003.55	$400.00	0.00119	19.85
53.5 - 54.5	$318,189.48	$0.00	0.00000	19.83
54.5 - 55.5	$317,325.59	$0.00	0.00000	19.83
55.5 - 56.5	$313,830.63	$0.00	0.00000	19.83
56.5 - 57.5	$301,579.65	$0.00	0.00000	19.83
57.5 - 58.5	$301,579.65	$0.00	0.00000	19.83

MDU-Common Plant

Account 390-Structures & Improvements

Calculation of Implicit Average Service Life

Investment	$1,000,000	Cost	Life (Yrs)	Component Inflation	
Superstructure	50%	$500,000	60		
Components -- (HVAC,Roof, Interior-Upgrades/Repl, Carpet, Windows, Etc).	50%	$500,000	20	2%	

Year	Superstructure Cost	Recovery Period	Total Weight	Component Cost	Recovery Period	Total Weight	Component Inflation Factor	Weighted ASL (Yrs)	Sum Weights
1	500,000	60	30,000,000	500,000	20	10,000,000	1.00		40,000,000
2	500,000	60	30,000,000	500,000	20	10,000,000	1.02		
3	500,000	60	30,000,000	500,000	20	10,000,000	1.04		
4	500,000	60	30,000,000	500,000	20	10,000,000	1.06		
5	500,000	60	30,000,000	500,000	20	10,000,000	1.08		
6	500,000	60	30,000,000	500,000	20	10,000,000	1.10		
7	500,000	60	30,000,000	500,000	20	10,000,000	1.13		
8	500,000	60	30,000,000	500,000	20	10,000,000	1.15		
9	500,000	60	30,000,000	500,000	20	10,000,000	1.17		
10	500,000	60	30,000,000	500,000	20	10,000,000	1.20		
11	500,000	60	30,000,000	500,000	20	10,000,000	1.22		
12	500,000	60	30,000,000	500,000	20	10,000,000	1.24		
13	500,000	60	30,000,000	500,000	20	10,000,000	1.27		
14	500,000	60	30,000,000	500,000	20	10,000,000	1.29		
15	500,000	60	30,000,000	500,000	20	10,000,000	1.32		
16	500,000	60	30,000,000	500,000	20	10,000,000	1.35		
17	500,000	60	30,000,000	500,000	20	10,000,000	1.37		
18	500,000	60	30,000,000	500,000	20	10,000,000	1.40		
19	500,000	60	30,000,000	500,000	20	10,000,000	1.43		
20	500,000	60	30,000,000	500,000	20	10,000,000	1.46		
21	500,000	60	30,000,000	728,406	20	14,568,112			14,568,112
22	500,000	60	30,000,000	728,406	20	14,568,112			
23	500,000	60	30,000,000	728,406	20	14,568,112			
24	500,000	60	30,000,000	728,406	20	14,568,112			
25	500,000	60	30,000,000	728,406	20	14,568,112			
26	500,000	60	30,000,000	728,406	20	14,568,112			
27	500,000	60	30,000,000	728,406	20	14,568,112			
28	500,000	60	30,000,000	728,406	20	14,568,112			
29	500,000	60	30,000,000	728,406	20	14,568,112			
30	500,000	60	30,000,000	728,406	20	14,568,112			
31	500,000	60	30,000,000	728,406	20	14,568,112			
32	500,000	60	30,000,000	728,406	20	14,568,112			
33	500,000	60	30,000,000	728,406	20	14,568,112			
34	500,000	60	30,000,000	728,406	20	14,568,112			
35	500,000	60	30,000,000	728,406	20	14,568,112			
36	500,000	60	30,000,000	728,406	20	14,568,112			
37	500,000	60	30,000,000	728,406	20	14,568,112			
38	500,000	60	30,000,000	728,406	20	14,568,112			
39	500,000	60	30,000,000	728,406	20	14,568,112			
40	500,000	60	30,000,000	870,512	20	17,410,242			17,410,242
41	500,000	60	30,000,000	870,512	20	17,410,242			
42	500,000	60	30,000,000	870,512	20	17,410,242			
43	500,000	60	30,000,000	870,512	20	17,410,242			
44	500,000	60	30,000,000	870,512	20	17,410,242			
45	500,000	60	30,000,000	870,512	20	17,410,242			
46	500,000	60	30,000,000	870,512	20	17,410,242			
47	500,000	60	30,000,000	870,512	20	17,410,242			
48	500,000	60	30,000,000	870,512	20	17,410,242			
49	500,000	60	30,000,000	870,512	20	17,410,242			
50	500,000	60	30,000,000	870,512	20	17,410,242			
51	500,000	60	30,000,000	870,512	20	17,410,242			
52	500,000	60	30,000,000	870,512	20	17,410,242			
53	500,000	60	30,000,000	870,512	20	17,410,242			
54	500,000	60	30,000,000	870,512	20	17,410,242			
55	500,000	60	30,000,000	870,512	20	17,410,242			
56	500,000	60	30,000,000	870,512	20	17,410,242			
57	500,000	60	30,000,000	870,512	20	17,410,242			
58	500,000	60	30,000,000	870,512	20	17,410,242			
59	500,000	60	30,000,000	870,512	20	17,410,242			
60	500,000	60	30,000,000	870,512	20	17,410,242			
	Superstructure		Componet-1st Replacements	Componet-2nd Replacement		Sum of Investments			
Investments	500,000		728,406	870,512		2,098,918		34.29	71,978,354

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

Before the Public Service Commission of Montana

Docket No. D2012.9.100

Rebuttal Testimony
of
Tamie A. Aberle

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

2 A. Yes. My name is Tamie A. Aberle, and my business address is 400
3 North Fourth Street, Bismarck, North Dakota 58501.

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

5 A. I am the Director of Regulatory Affairs for Montana-Dakota Utilities
6 Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

7 **Q. Are you the same Tamie A. Aberle who filed direct testimony in this**
8 **proceeding?**

9 A. Yes, I am.

10 **Q. What is the purpose of your rebuttal testimony?**

11 A. The purpose of this rebuttal testimony is to address
12 recommendations made by Mr. George L. Donkin, testifying on behalf of
13 the Montana Consumer Counsel, regarding the marginal cost of service
14 study, embedded cost of service study, rate design and the Company's
15 proposed Distribution Delivery Stabilization Mechanism.

16 **Q. Do you have any corrections to make to the embedded class cost of**
17 **service study filed as Statement L in the Company's Application**

submitted on September 26, 2012?

A. Yes I do. Through the discovery process, Montana-Dakota discovered that the peak day deliveries utilized in the demand allocator for the embedded class cost of service study inadvertently excluded peak day volumes delivered through the Northwestern Energy interconnection at Billings, Montana. The correction of this error resulted in changes to Allocation Factor No. 2 – Peak Day deliveries and Factor No. 5 – Peak Day Deliveries at Distribution. The correction resulted in the following changes in the two allocation factors by rate class:

Factor 2 – 1 Day Peak	As Filed	Corrected
Residential Service	52.262320	53.169355
Small Firm General Service	10.829535	11.018293
Large Firm General Service	21.915384	22.295703
Small Interruptible Sales & Transportation	2.658588	2.396836
Large Interruptible Sales & Transportation	12.334173	11.119813

Factor 5 – Peak Day @ Distribution	As Filed	Corrected
Residential Service	56.400869	56.940858
Small Firm General Service	11.774888	11.878312
Large Firm General Service	23.729884	23.947872
Small Interruptible Sales & Transportation	2.347259	2.097464
Large Interruptible Sales & Transportation	5.747100	5.135494

Q. Have you prepared an updated embedded cost of service study reflecting the revised demand allocation factors?

A. Yes. I have prepared an updated embedded cost of service study and I have provided the updated study as Exhibit No.___(TAA-7). The revised allocation factors noted above are the only change reflected in Exhibit No.___(TAA-7) and the updated study does not reflect changes in

the revenue requirement or costs to be allocated as identified by Ms. Mulkern in her rebuttal testimony in order to isolate the affect of the revised allocation factors. The revised allocation factors changed the allocation of demand related costs among the customer classes and resulted in the following rate of return produced by each rate class.

Return on Rate Base	As Filed	Corrected
Residential Service	0.278%	0.231%
Small Firm General Service	11.364%	11.268%
Large Firm General Service	7.444%	7.365%
Small Interruptible Sales & Transportation	40.315%	43.166%
Large Interruptible Sales & Transportation	13.934%	17.617%

Q. Mr. Donkin at page 14 of his testimony states that variable costs, which are largely the costs of purchased gas and other related gas supply expenses, are almost always allocated among customers on the basis of their respective annual usage. Do you agree with this assessment?

A. Yes I do. Montana-Dakota's embedded class cost of service study reflects this theory and the only costs allocated on annual energy deliveries are those costs associated with gas supply.

Q. Mr. Donkin also at page 14 of his testimony states that peak period or peak day usage levels; seasonal usage levels and annual usage levels are often observed as factors for allocating fixed capacity-related gas utility costs and that a combination of these factors should be used to allocate fixed capacity-related costs among customers or customer classes. Do you agree with this premise?

1 A. I do not. This argument does not appropriately reflect the cause of
2 the fixed capacity related costs. While the notion may be supported by the
3 methodology foundation for the Federal Power Commission's (FPC) 1952
4 Atlantic-Seaboard Decision, used by Mr. Donkin to support his
5 recommended allocation, that decision has been superseded over time
6 and I fail to see the relevance of this 1952 decision in ratemaking today.
7 The FPC's successor, the Federal Energy Regulatory Commission
8 methodology currently used, adopted with the issuance of the landmark
9 Order 636, functionalizes pipeline capacity costs using the Straight Fixed-
10 Variable (SFV) Method. Under the SFV Method all fixed costs are
11 classified to the demand component and all variable costs are classified to
12 the commodity component. The SFV method does not support Mr.
13 Donkin's proposal to allocate fixed capacity related costs on a
14 demand/energy allocator.
15 **Q. Mr. Donkin disagrees with the allocation of distribution mains based**
16 **on peak day demands and at page 17 of his testimony concludes it is**
17 **incorrect to do so because distribution mains never would have been**
18 **built if their sole purpose was to serve customer demands on a**
19 **single peak day. Do you agree with Mr. Donkin?**
20 A. I do not agree. Distribution mains must be designed to be capable
21 of delivering peak day requirements and therefore it is appropriate to
22 allocate the investment in distribution mains to customer classes based on
23 their contribution to the peak day requirements. Mr. Donkin's opinion that

1 the main purpose of distribution mains is to meet annual Dk throughput
2 requirements and therefore it is appropriate to classify and allocate a
3 significant portion of the costs of distribution mains on annual Dk volumes,
4 incorrectly assigns more costs to higher load factor customers that more
5 efficiently make use of the investment needed to meet peak day
6 requirements.

7 **Q. Is Mr. Donkin's example regarding peak day and average volumes at**
8 **page 19 of his testimony relevant to natural gas service provided in**
9 **Montana-Dakota's Montana service territory?**

10 A. No. Mr. Donkin suggests that if there were no variation over the
11 course of the year in annual throughput, Montana-Dakota's distribution
12 pipeline system would require a peak day delivery capacity of at least
13 33,613 Dk. The fact is there is significant variation over the course of the
14 year on a system used primarily for space heating with firm customer
15 requirements of only 178,000 dk in August as compared to 1.8 MMDk in
16 January. The allocation of distribution mains necessary to meet the
17 January requirements on the basis of annual energy use is inconsistent
18 with the objective of allocating costs based on the cause of the cost.

19 **Q. Is the 50% peak demand and 50% annual demand allocation factor**
20 **Mr. Donkin uses to allocate the investment in Distribution Mains**
21 **calculated correctly?**

22 A. No. Mr. Donkin's allocation factor, in addition to being misapplied,
23 is also calculated based on total energy delivered, including volumes

delivered to transmission level customers (in all rate classes) that are not utilizing the distribution mains. Mr. Donkin's peak demand factor correctly excludes the transmission level deliveries on peak but the energy factor used in his weighted factor incorrectly includes the transmission level deliveries. Following is a comparison of the energy component of Mr. Donkin's weighted Factor 45 reflecting this correction and the factor used by Mr. Donkin. As shown, this error results in a cost shift to the Large Interruptible Sales and Transportation classes.

Factor 45 (Energy)	Donkin	Corrected
Residential Service	40.381598	48.663314
Small Firm General Service	7.412135	8.879499
Large Firm General Service	17.845655	21.317574
Small Interruptible Sales & Transportation	5.992734	5.929368
Large Interruptible Sales & Transportation	27.801612	14.518137

Q. Do you agree with Mr. Donkin's proposal to allocate Services, Service Regulators and Meters on the basis of 50% peak day Dk volumes and 50% number of customers?

A. No. Mr. Donkin provides no basis for the allocation of costs that are clearly customer related, based on peak day requirements. Service lines are clearly customer related costs as the investment in service lines varies directly with the number of customers served rather than the amount of utility service provided. The June 1989 version of the Gas Distribution Rate Design Manual prepared by the NARUC Staff Subcommittee on Gas supports Montana-Dakota's basis for allocating services solely on the basis of customers. Mr. Donkin's proposal should

be rejected. Further, Mr. Donkin erroneously used the Company's weighted customer factor in his cost study. The weighted customer factor already addresses the nature of the customer class requirements by applying a weighting factor to the meter costs for each class to reflect the fact that the metering and service line costs to serve firm general service and the interruptible sales customers are higher than the cost to serve residential customers. Coupling this weighted customer factor with the peak day allocator overstates the allocation of costs to the firm general service and interruptible classes. The meter, service regulators and service line costs should be classified as customer related costs and allocated on the basis of weighted customers. As noted in the past, this allocation methodology is widely accepted and appropriate for use in this case. Mr. Donkin's allocation of meters and services again shifts costs from the Residential and Firm General Service classes to the interruptible service classes and inappropriately classifies a portion of these customer related costs as demand related costs.

Q. Would you please address Mr. Donkin's allocation of Administration and General expenses?

A. Yes. Mr. Donkin proposes to allocate Administration and General expenses on the basis of 50% peak day demand and 50% annual Dk demands as noted at page 23 of his testimony. The reason provided by Mr. Donkin was because much of Montana-Dakota's business activities and related A&G expenses are incurred in connection with the Company's

1 daily, monthly, seasonal, and annual gas supply and demand activities
2 and not with the O&M expenses that are incurred to provide for the
3 physical delivery of gas to customers. For this reason Mr. Donkin
4 arbitrarily uses an allocation factor that results in a higher percentage of
5 costs being allocated to the larger customers. If, in fact, A&G expenses
6 were only gas supply related as he suggests, an allocation factor including
7 transportation service volumes as he has done would not be correct.
8 Montana-Dakota's allocation of A&G expenses based on O&M expenses,
9 excluding the cost of gas, appropriately classifies A&G expenses as
10 demand, energy and customer related while Mr. Donkin's allocation does
11 not classify any A&G expenses as customer related expenses.
12 **Q. Do you agree with Mr. Donkin's proposed allocation of customer**
13 **class revenues as provided in Exhibit ___(GLD-3)?**
14 A. I do not agree with the proposed allocation of revenues for the
15 same reasons I do not agree with Mr. Donkin's embedded cost of service
16 study. Mr. Donkin's change in allocation factors results in shifting costs
17 away from the residential class and moving those costs to the interruptible
18 service classes. This results in an overstatement of a revenue
19 responsibility assigned to the interruptible classes. The allocation of
20 revenues supported by Montana-Dakota's embedded class cost of service
21 study should be adopted.
22 **Q. Mr. Donkin has proposed that the Residential Basic Service Charge**
23 **or Fixed Monthly Charge be held at the current level. Do you agree**

with this proposal and the rationale for doing so provided by Mr. Donkin at pages 31-34 of his testimony?

A. I do not. First, Mr. Donkin's comparison of bills under present and proposed rates does not reflect the total bill to the customer and therefore paints a more dramatic effect of the Company's proposed Basic Service Charge than will be experienced by customers. The comparison distorts the affect of the increase as it excludes the variable component of a customer's bill, the gas commodity cost, which represents approximately 70 percent of a typical residential customer's winter bill, thus the "price signal" afforded to a customer is not realistic. The increase in the Basic Service Charge will serve to stabilize customers' bills. The customer using more energy continues to have a sufficient price signal to conserve the use of natural gas to avoid paying the gas commodity charge that represents more than half of the total bill. Maintaining the current Basic Service Charge does nothing to address the subsidy provided by the customer utilizing at least the average energy use of 86 dk annually to the customer utilizing 35 dk on annual basis. Less than average annual energy use does not necessarily equate to less of a contribution toward peak requirements. Even Mr. Donkin recognizes that at least 50% of the investment in distribution mains is associated with peak deliveries. Continuing to recover fixed distribution costs on a volumetric basis unduly discriminates in favor of the low use customers and continues the current intra-class subsidies.

The customer cost component identified in Mr. Donkin's own embedded class study supports a monthly customer-related charge of approximately $7.50 for the residential class. Montana-Dakota's proposed Basic Service Charge moves the charge closer to the cost identified in Montana-Dakota's embedded class cost of service study and therefore, the Company's proposed Basic Service Charges are supported by its cost studies and should be adopted in this proceeding.

Q. Do you have any comments concerning Mr. Donkin's discussion of the Company's DDSM alternative?

A. Yes, I do. The DDSM only applies to the variance between actual and normal weather as it relates to the distribution component of a customer's bill, which is a minor portion of the total bill (distribution costs represent approximately 34% of a residential customer's total annual bill). DDSM is not a revenue "decoupling" proposal similar to Northwestern Energy's proposal. I will address each of the reasons Mr. Donkin provides, starting on page 36 of his testimony, in support of his recommendation that the proposed DDSM not be approved:

- *"DDSM is a single-issue ratemaking device that can produce periodic rate increases without taking into account other factors that would support no rate change or, even a rate reduction."* This is not true, the DDSM simply adjusts the amount billed for the distribution delivery charge upwards or DOWNWARDS to reflect normal weather. The DDSM adjustment is applied on each

customer's bill based on weather experienced in the current service period. As rates are established based on normal weather the adjustment is not a single ratemaking device, rather a mechanism to represent volume levels utilized to establish rates in the rate case process. Customer growth is not intended to offset the effects of warmer than normal weather. In the event weather is colder than normal, customers will receive a credit on their bill regardless of customer growth.

- *"If approved, MDU's proposed DDSM would distort price signals to the Company's Residential and General Service ratepayers."* As noted on frequent occasions in this docket and prior dockets, the DDSM adjustment is applied in the current billing period and will not cause a distortion in price signals as suggested by Mr. Donkin. Further, the adjustment is based only on the Distribution Delivery Charge. For example, in a colder than normal billing period, the customer will see a credit based on the distribution delivery charge and the cost of gas (majority of the bill) will be based on actual use which presumably would be higher than normal because of the cold weather. I do not believe a DDSM credit will incent a customer to use more natural gas than they otherwise would. The cost of gas component of the bill will provide the incentive to reduce usage.
- *"The proposed DDSM also would reduce MDU's business risk, relative to the business risk that likely was used by the Commission*

1 *in arriving at the cost of capital associated with the Company's*
2 *investments in gas utility operations."* First, this is conjecture by Mr.
3 Donkin and secondly, as noted by Dr. Gaske at page 33 of his
4 direct testimony, the higher than average business risk is
5 associated with a number of factors, such as the exposure to a
6 relatively undiversified local economy and throughput risks
7 associated with declining average use per customer while
8 significant fixed costs are at risk in the usage charge. DDSM will
9 not alleviate any of these business risks because DDSM is not full
10 decoupling.
11 **Q. Ms. Aberle do you agree with Mr. Donkin's comments regarding the**
12 **use of embedded cost of service studies versus a marginal cost of**
13 **service study for the purpose of examining distribution costs as set**
14 **forth on pages 4 through 11 of his testimony?**
15 A. Yes, I do. I also request the Commission determine that the
16 embedded class cost of service study is the appropriate process to use for
17 cost allocation supporting rate design in future cases.
18 **Q. Does this conclude your rebuttal testimony?**
19 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
Embedded Class Cost of Service Study
Cost of Service by Component
Pro Forma 2012

	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
Rate Base	43,247,508	8,629,668	4,871,709	14,395,677	27,897,054
Adjustments to Rate Base	512,331	(499,548)	(644,345)	2,132,722	988,829
Pro Forma Rate Base	43,759,839	8,130,120	4,227,364	16,528,399	28,885,883
Operating Income for Proposed Return	3,714,772	690,166	358,861	1,403,095	2,452,122
Current Operating Income	3,628,296	(1,258,036)	4,202,218	(1,501,802)	1,442,380
Adjustment to Operating Income	(2,001,274)	(177,707)	(544,588)	(653,490)	(1,375,785)
Required Increase in Operating Income	2,087,750	2,125,909	(3,298,769)	3,558,387	2,385,527
Related Taxes for Increase					
Federal Income	1,356,675	1,381,470	(2,143,625)	2,312,333	1,550,178
Revenue Tax	11,057	11,260	(17,472)	18,847	12,635
Total Increase in Revenue	3,455,482	3,518,639	(5,459,866)	5,889,567	3,948,340
Retail Revenue Before Increase					
Per Books	73,742,148	7,326,501	32,214,298	5,221,303	44,762,102
Pro Forma Adjustments	(14,819,134)	159,399	(9,316,550)	124,965	(9,032,186)
Total Retail Revenue Before Increase	58,923,014	7,485,900	22,897,748	5,346,268	35,729,916
Total Cost of Service Required from Rates	62,378,496	11,004,539	17,437,882	11,235,835	39,678,256
Less Cost of Gas	38,854,572	7,482,150	16,034,347	0	23,516,497
Net Distribution Cost of Service	23,523,924	3,522,389	1,403,535	11,235,835	16,161,759
Pro Forma Rate of Return	3.720%	-17.660%	86.523%	-13.040%	0.231%
Pro Forma Billing Units					
Dk	15,014,099	6,097,461	6,097,461	6,097,461	
Bills	946,920			841,932	
Unit Cost of Service					
Energy cost per Dk			$0.230		
Demand cost per DK		$0.578			
Customer Cost Per Month				$13.350	

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
Embedded Class Cost of Service Study
Cost of Service by Component
Pro Forma 2012

	Total Montana	Small Firm General			Total Small Firm General	Large Firm General			Total Large Firm General
		Demand	Energy	Customer		Demand	Energy	Customer	
Rate Base	43,247,508	1,798,587	856,463	1,533,212	4,188,262	3,627,438	2,188,974	3,948,874	9,765,286
Adjustments to Rate Base	512,331	(104,000)	(111,443)	199,056	(16,387)	(209,738)	(291,271)	96,575	(404,434)
Pro Forma Rate Base	43,759,839	1,694,587	745,020	1,732,268	4,171,875	3,417,700	1,897,703	4,045,449	9,360,852
Operating Income for Proposed Return	3,714,772	143,853	63,245	147,052	354,150	290,129	161,096	343,418	794,643
Current Operating Income	3,628,296	(262,425)	816,861	10,073	564,509	(528,965)	2,144,246	(531,394)	1,083,887
Adjustment to Operating Income	(2,001,274)	(37,268)	5,483	(62,642)	(94,427)	(74,875)	(174,789)	(144,835)	(394,499)
Required Increase in Operating Income	2,087,750	443,546	(759,099)	199,621	(115,932)	893,969	(1,808,361)	1,019,647	105,255
Related Taxes for Increase									
Federal Income	1,356,675	288,228	(493,283)	129,719	(75,336)	580,924	(1,175,119)	662,593	68,398
Revenue Tax	11,057	2,349	(4,020)	1,057	(614)	4,735	(9,578)	5,400	557
Total Increase in Revenue	3,455,482	734,123	(1,256,402)	330,397	(191,882)	1,479,628	(2,993,058)	1,687,640	174,210
Retail Revenue Before Increase									
Per Books	73,742,148	1,518,161	6,011,434	799,917	8,329,512	3,072,253	14,311,823	551,733	17,935,809
Pro Forma Adjustments	(14,819,134)	33,030	(1,731,577)	17,149	(1,681,398)	66,842	(3,411,933)	17,951	(3,327,140)
Total Retail Revenue Before Increase	58,923,014	1,551,191	4,279,857	817,066	6,648,114	3,139,095	10,899,890	569,684	14,608,669
Total Cost of Service Required from Rates	62,378,496	2,285,314	3,023,455	1,147,463	6,456,232	4,618,723	7,906,832	2,257,324	14,782,879
Less Cost of Gas	38,854,572	1,550,414	2,766,094	0	4,316,508	3,137,522	7,255,016	0	10,392,538
Net Distribution Cost of Service	23,523,924	734,900	257,361	1,147,463	2,139,724	1,481,201	651,816	2,257,324	4,390,341
Pro Forma Rate of Return	3.720%	-17.685%	110.379%	-3.035%	11.268%	-17.668%	103.781%	-16.716%	7.365%
Pro Forma Billing Units									
Dk	15,014,099	1,119,203	1,119,203	1,119,203		2,694,623	2,694,623	2,694,623	
Bills	946,920			78,564				25,836	
Unit Cost of Service									
Energy cost per Dk			$0.230				$0.242		
Demand cost per DK		$0.657				$0.550			
Customer Cost Per Month				$14.610				$87.370	

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Cost of Service by Component
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	Total Montana	Small Interruptible			Total Small Interruptible	Large Interruptible			Total Large Interruptible
		Demand	Energy	Customer		Demand	Energy	Customer	
Rate Base	43,247,508	302,536	166,595	209,788	678,919	660,436	0	57,551	717,987
Adjustments to Rate Base	512,331	(16,400)	(21,646)	3,652	(34,394)	(21,880)	0	597	(21,283)
Pro Forma Rate Base	43,759,839	286,136	144,949	213,440	644,525	638,556	0	58,148	696,704
Operating Income for Proposed Return	3,714,772	24,290	12,305	18,119	54,714	54,207	0	4,936	59,143
Current Operating Income	3,628,296	(52,863)	395,071	(18,609)	323,599	(112,909)	313,691	13,139	213,921
Adjustment to Operating Income	(2,001,274)	(10,783)	(23,107)	(11,491)	(45,381)	(27,002)	(55,548)	(8,632)	(91,182)
Required Increase in Operating Income	2,087,750	87,936	(359,659)	48,219	(223,504)	194,118	(258,143)	429	(63,596)
Related Taxes for Increase									
Federal Income	1,356,675	57,143	(233,716)	31,334	(145,239)	126,143	(167,748)	279	(41,326)
Revenue Tax	11,057	466	(1,905)	255	(1,184)	1,028	(1,367)	2	(337)
Total Increase in Revenue	3,455,482	145,545	(595,280)	79,808	(369,927)	321,289	(427,258)	710	(105,259)
Retail Revenue Before Increase									
Per Books	73,742,148	84,042	1,802,553	85,147	1,971,742	0	700,340	42,643	742,983
Pro Forma Adjustments	(14,819,134)	1,828	(587,912)	1,853	(584,231)	0	(183,336)	(10,843)	(194,179)
Total Retail Revenue Before Increase	58,923,014	85,870	1,214,641	87,000	1,387,511	0	517,004	31,800	548,804
Total Cost of Service Required from Rates	62,378,496	231,415	619,361	166,808	1,017,584	321,289	89,746	32,510	443,545
Less Cost of Gas	38,854,572	91,968	537,061	0	629,029	0	0	0	0
Net Distribution Cost of Service	23,523,924	139,447	82,300	166,808	388,555	321,289	89,746	32,510	443,545
Pro Forma Rate of Return	3.720%	-22.243%	256.617%	-14.102%	43.166%	-21.911%	0.000%	7.751%	17.617%
Pro Forma Billing Units									
Dk	15,014,099	904,879	904,879	904,879		4,197,933	4,197,933	4,197,933	
Bills	946,920			528				60	
Unit Cost of Service									
Energy cost per Dk			$0.091				$0.021		
Demand cost per DK		$0.154				$0.077			
Customer Cost Per Month				$315.920				$541.830	

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Operating Income and Rate of Return	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential	Small Firm General Demand	Small Firm General Energy	Small Firm General Customer	Total Small Firm General
Sales Revenues	73,742,148	7,326,501	32,214,298	5,221,303	44,762,102	1,518,161	6,011,434	799,917	8,329,512
Adjustments to Sales Revenues	(14,819,134)	159,399	(9,316,550)	124,965	(9,032,186)	33,030	(1,731,577)	17,149	(1,681,398)
Total Sales Revenues	58,923,014	7,485,900	22,897,748	5,346,268	35,729,916	1,551,191	4,279,857	817,066	6,648,114
Other Revenues	368,826	63,266	13,753	173,543	250,562	13,202	2,525	17,609	33,336
Adjustments to Other Revenues	47,286	11,516	0	19,113	30,629	2,405	0	1,979	4,384
Total Other Revenues	416,112	74,782	13,753	192,656	281,191	15,607	2,525	19,588	37,720
Total Operating Revenues	59,339,126	7,560,682	22,911,501	5,538,924	36,011,107	1,566,798	4,282,382	836,654	6,685,834
Operating Expense									
Cost of Gas	52,735,031	7,482,150	24,428,140	0	31,910,290	1,550,414	4,502,040	0	6,052,454
Adj. Cost of Gas	(13,880,459)	0	(8,393,793)	0	(8,393,793)	0	(1,735,946)	0	(1,735,946)
Total Cost of Gas	38,854,572	7,482,150	16,034,347	0	23,516,497	1,550,414	2,766,094	0	4,316,508
Other O&M Expense	10,869,312	1,318,019	335,728	6,173,101	7,826,848	274,952	61,626	609,718	946,296
Adjustments to Other O&M	247,763	39,555	5,012	124,530	169,097	8,252	919	12,575	21,746
Total Other O&M Expense	11,117,075	1,357,574	340,740	6,297,631	7,995,945	283,204	62,545	622,293	968,042
Total Operation & Maint. Exp.	49,971,647	8,839,724	16,375,087	6,297,631	31,512,442	1,833,618	2,828,639	622,293	5,284,550
Depreciation Expense	3,011,299	504,388	61,152	1,431,846	1,997,386	105,360	11,225	147,599	264,184
Adjustment to Depreciation Exp.	1,412,303	262,697	1,092	731,026	994,815	54,857	201	72,676	127,734
Total Depreciation Expense	4,423,602	767,085	62,244	2,162,872	2,992,201	160,217	11,426	220,275	391,918

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Operating Income and Rate of Return	Total Montana	Residential			Total Residential	Small Firm General			Total Small Firm General
		Demand	Energy	Customer		Demand	Energy	Customer	
Taxes Other Than Income Taxes	3,308,020	698,561	190,897	1,266,600	2,156,058	145,797	35,504	131,571	312,872
Adj. to Taxes Other Than Income	(32,521)	8,546	(63,200)	41,952	(12,702)	1,818	(11,820)	3,539	(6,463)
Total Taxes Other Than Income	3,275,499	707,107	127,697	1,308,552	2,143,356	147,615	23,684	135,110	306,409
Current Inc. Taxes - Fed. & State	(2,930,185)	(2,038,692)	2,871,301	(3,430,807)	(2,598,198)	(425,352)	561,166	(232,470)	(96,656)
Adj. to Current Income Taxes	(362,884)	29,762	(288,740)	(22,730)	(281,708)	6,058	15,521	1,320	22,899
Total Current Income Taxes	(3,293,069)	(2,008,930)	2,582,561	(3,453,537)	(2,879,906)	(419,294)	576,687	(231,150)	(73,757)
Deferred Income Taxes	3,489,201	683,377	138,615	1,455,908	2,277,900	142,617	25,537	151,035	319,189
Adj. to Deferred Income Tax	(154,777)	8,062	(32,333)	(77,209)	(101,480)	1,718	(5,935)	(8,340)	(12,557)
Total Deferred Income Taxes	3,334,424	691,439	106,282	1,378,699	2,176,420	144,335	19,602	142,695	306,632
Total Operating Expenses	57,712,103	8,996,425	19,253,871	7,694,217	35,944,513	1,866,491	3,460,038	889,223	6,215,752
Pro Forma Operating Income	1,627,023	(1,435,743)	3,657,630	(2,155,293)	66,594	(299,693)	822,344	(52,569)	470,082
Rate Base	43,247,508	8,629,668	4,871,709	14,395,677	27,897,054	1,798,587	856,463	1,533,212	4,188,262
Adjustment to Rate Base	512,331	(499,548)	(644,345)	2,132,722	988,829	(104,000)	(111,443)	199,056	(16,387)
Total Pro Forma Rate Base	43,759,839	8,130,120	4,227,364	16,528,399	28,885,883	1,694,587	745,020	1,732,268	4,171,875
Pro Forma Rate of Return	3.72%	-17.660%	86.523%	-13.040%	0.231%	-17.685%	110.379%	-3.035%	11.268%

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Operating Income and Rate of Return	Total Montana	Large Firm General			Total Large Firm General	Small Interruptible			Total Small Interruptible
		Demand	Energy	Customer		Demand	Energy	Customer	
Sales Revenues	73,742,148	3,072,253	14,311,823	551,733	17,935,809	84,042	1,802,553	85,147	1,971,742
Adjustments to Sales Revenues	(14,819,134)	66,842	(3,411,933)	17,951	(3,327,140)	1,828	(587,912)	1,853	(584,231)
Total Sales Revenues	58,923,014	3,139,095	10,899,890	569,684	14,608,669	85,870	1,214,641	87,000	1,387,511
Other Revenues	368,826	26,608	6,077	39,241	71,926	2,541	529	3,210	6,280
Adjustments to Other Revenues	47,286	4,843	0	5,337	10,180	498	0	448	946
Total Other Revenues	416,112	31,451	6,077	44,578	82,106	3,039	529	3,658	7,226
Total Operating Revenues	59,339,126	3,170,546	10,905,967	614,262	14,690,775	88,909	1,215,170	90,658	1,394,737
Operating Expense									
Cost of Gas	52,735,031	3,137,522	10,365,633	0	13,503,155	91,968	1,085,155	0	1,177,123
Adj. Cost of Gas	(13,880,459)	0	(3,110,617)	0	(3,110,617)	0	(548,094)	0	(548,094)
Total Cost of Gas	38,854,572	3,137,522	7,255,016	0	10,392,538	91,968	537,061	0	629,029
Other O&M Expense	10,869,312	554,324	148,367	1,037,535	1,740,226	52,127	21,186	80,913	154,226
Adjustments to Other O&M	247,763	16,636	2,215	27,761	46,612	1,564	454	2,265	4,283
Total Other O&M Expense	11,117,075	570,960	150,582	1,065,296	1,786,838	53,691	21,640	83,178	158,509
Total Operation & Maint. Exp.	49,971,647	3,708,482	7,405,598	1,065,296	12,179,376	145,659	558,701	83,178	787,538
Depreciation Expense	3,011,299	212,133	27,025	399,855	639,013	22,450	2,192	33,225	57,867
Adjustment to Depreciation Exp.	1,412,303	110,484	483	130,807	241,774	11,353	39	10,395	21,787
Total Depreciation Expense	4,423,602	322,617	27,508	530,662	880,787	33,803	2,231	43,620	79,654

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Operating Income and Rate of Return	Total Montana	Large Firm General			Total Large Firm General	Small Interruptible			Total Small Interruptible
		Demand	Energy	Customer		Demand	Energy	Customer	
Taxes Other Than Income Taxes	3,308,020	293,741	89,079	319,839	702,659	28,690	9,599	26,828	65,117
Adj. to Taxes Other Than Income	(32,521)	3,620	(30,146)	12,992	(13,534)	1,034	(3,365)	965	(1,366)
Total Taxes Other Than Income	3,275,499	297,361	58,933	332,831	689,125	29,724	6,234	27,793	63,751
Current Inc. Taxes - Fed. & State	(2,930,185)	(857,310)	1,482,383	(1,041,434)	(416,361)	(83,377)	284,890	(68,226)	133,287
Adj. to Current Income Taxes	(362,884)	12,430	(84,791)	24,149	(48,213)	(1,948)	(12,680)	2,573	(12,055)
Total Current Income Taxes	(3,293,069)	(844,880)	1,397,592	(1,017,285)	(464,574)	(85,325)	272,210	(65,653)	121,232
Deferred Income Taxes	3,489,201	287,416	61,167	406,573	755,156	27,588	4,989	34,226	66,803
Adj. to Deferred Income Tax	(154,777)	3,390	(14,288)	(27,586)	(38,484)	1,106	(1,159)	(2,406)	(2,459)
Total Deferred Income Taxes	3,334,424	290,806	46,879	378,987	716,672	28,694	3,830	31,820	64,344
Total Operating Expenses	57,712,103	3,774,386	8,936,510	1,290,491	14,001,386	152,555	843,206	120,758	1,116,519
Pro Forma Operating Income	1,627,023	(603,840)	1,969,457	(676,229)	689,389	(63,646)	371,964	(30,100)	278,218
Rate Base	43,247,508	3,627,438	2,188,974	3,948,874	9,765,286	302,536	166,595	209,788	678,919
Adjustment to Rate Base	512,331	(209,738)	(291,271)	96,575	(404,434)	(16,400)	(21,646)	3,652	(34,394)
Total Pro Forma Rate Base	43,759,839	3,417,700	1,897,703	4,045,449	9,360,852	286,136	144,949	213,440	644,525
Pro Forma Rate of Return	3.72%	-17.668%	103.781%	-16.716%	7.365%	-22.243%	256.617%	-14.102%	43.166%

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Operating Income and Rate of Return	Total Montana	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Sales Revenues	73,742,148	0	700,340	42,643	742,983
Adjustments to Sales Revenues	(14,819,134)	0	(183,336)	(10,843)	(194,179)
Total Sales Revenues	58,923,014	0	517,004	31,800	548,804
Other Revenues	368,826	5,970	220	532	6,722
Adjustments to Other Revenues	47,286	1,073	0	74	1,147
Total Other Revenues	416,112	7,043	220	606	7,869
Total Operating Revenues	59,339,126	7,043	517,224	32,406	556,673
Operating Expense					
Cost of Gas	52,735,031	0	92,009	0	92,009
Adj. Cost of Gas	(13,880,459)	0	(92,009)	0	(92,009)
Total Cost of Gas	38,854,572	0	0	0	0
Other O&M Expense	10,869,312	132,277	55,980	13,459	201,716
Adjustments to Other O&M	247,763	3,968	1,679	378	6,025
Total Other O&M Expense	11,117,075	136,245	57,659	13,837	207,741
Total Operation & Maint. Exp.	49,971,647	136,245	57,659	13,837	207,741
Depreciation Expense	3,011,299	47,277	0	5,572	52,849
Adjustment to Depreciation Exp.	1,412,303	24,475	0	1,718	26,193
Total Depreciation Expense	4,423,602	71,752	0	7,290	79,042

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Operating Income and Rate of Return	Total Montana	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Taxes Other Than Income Taxes	3,308,020	61,324	5,430	4,560	71,314
Adj. to Taxes Other Than Income	(32,521)	2,794	(1,362)	112	1,544
Total Taxes Other Than Income	3,275,499	64,118	4,068	4,672	72,858
Current Inc. Taxes - Fed. & State	(2,930,185)	(186,487)	233,450	780	47,743
Adj. to Current Income Taxes	(362,884)	(3,758)	(36,096)	(3,952)	(43,807)
Total Current Income Taxes	(3,293,069)	(190,245)	197,354	(3,172)	3,936
Deferred Income Taxes	3,489,201	64,488	0	5,665	70,153
Adj. to Deferred Income Tax	(154,777)	596	0	(393)	203
Total Deferred Income Taxes	3,334,424	65,084	0	5,272	70,356
Total Operating Expenses	57,712,103	146,954	259,081	27,899	433,933
Pro Forma Operating Income	1,627,023	(139,911)	258,143	4,507	122,740
Rate Base	43,247,508	660,436	0	57,551	717,987
Adjustment to Rate Base	512,331	(21,880)	0	597	(21,283)
Total Pro Forma Rate Base	43,759,839	638,556	0	58,148	696,704
Pro Forma Rate of Return	3.72%	-21.911%	0.000%	7.751%	17.617%